Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Testimony of Amparo Nieto
May 28, 2019

**STATE OF NEW HAMPSHIRE**

**BEFORE THE**

**NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION**

**DOCKET NO. DE 19-057**

**REQUEST FOR PERMANENT RATES**

# DIRECT TESTIMONY OF AMPARO NIETO

***Allocated Cost of Service Study***

**On behalf of the Public Service Company of New Hampshire**

**d/b/a Eversource Energy**

**May 28, 2019**

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## Attachments

Attachment ACOSS-1 - Resume Vitae of Amparo Nieto

Attachment ACOSS-2 – Proforma Cost of Service Study

Attachment ACOSS-3 – Per Books Cost of Service Study

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## I. INTRODUCTION

**Q. Please state your name and current position.**

A. My name is Amparo Nieto, and I am a Senior Vice President at Economists Incorporated ("EI").

**Q. Please summarize your qualifications and experience.**

A. I have over 20 years of experience providing advisory services and analyses on behalf of utilities, independent firms and energy regulatory commissions, in the context of energy regulatory policy design and wholesale electricity markets. I have advised extensively on the development of electricity marginal cost studies for use in the design of efficient rates and programs for utilities in California, Arizona, Maine, Minnesota, Oregon, New York, North Dakota, South Dakota and other states, as well as in provinces of Canada, such as in British Columbia, Manitoba and Newfoundland. I have reviewed and developed efficient utility electricity rate structures, recommended changes to utility demand response and interruptible rates, reviewed the impact of net metering rates on cost shifting among customers and designed improved compensation schemes for Distributed Energy Resources ("DER"). In New York, I was involved in the initial phase of the Reforming the Energy Vision (REV) docket, with regard to marginal distribution cost analysis for potential use in the Value of DER. I have also advised energy regulators and companies in Australia, Ireland, Spain, Africa and the Caribbean on electricity cost studies, regulatory policy, competitive markets, transmission cost allocation, distribution regulation and design of financial transmission rights. I contributed to the design and implementation of energy auction designs in Pennsylvania and Spain and advised the ISO-NE in various aspects of its wholesale capacity market rules. I am currently the director of the "Utility of the Future Rates Group," a working group sponsored by EI and open to energy utilities across North America. Additionally, I have conducted seminars on electricity marginal costing and rate design for rate managers and regulatory commission staff for over a decade. I have published energy papers and participated frequently as a panelist on industry and academic forums in the U.S. I hold a Master's degree in Economic Analysis and Public Finance from the Madrid Institute for Fiscal Studies in Madrid, Spain and a B.A. in Economics from the University of Carlos III of Madrid. My curriculum vitae is set forth in Attachment ACOSS-1.

**Q. Have you testified previously before other regulatory bodies?**

A. Yes. I have provided testimony before the Public Utilities Commission of Nevada, the New York Public Service Commission, the North Carolina Utilities Commission, the

Minnesota Public Utilities Commission, and the North Dakota Public Utilities Commission in the context of electricity marginal cost studies, electricity rate design and design of contracts with independent power producers. I have also provided expert testimony as part of the Salt River Project's price review process before its Board of Directors, with regard to SRP's proposal to reform their net metering rates. Overseas, I supported regulatory proceedings involving rate reforms in Ireland, Brazil, Kenya and Barbados.

**Q. On whose behalf are you testifying in this docket?**

A. I am testifying on behalf of Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH" or the "Company").

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to present the allocated cost of service study ("ACOSS") that I developed for PSNH for this rate case. In separate testimony, I also present the marginal cost of service study ("MCOSS") I prepared for PSNH, which represents an update to the MCOS study I developed in the context of the New Hampshire Net Metering proceeding (Docket No. DE 16-576). These studies provide information useful for class revenue requirements and rate design and I advised PSNH on the best manner to apply these results. The ACOSS is provided as Attachment ACOSS-2 (Pro Forma Cost of Service Study) and Attachment ACOSS-3 (Per Books Cost of Service Study).

**Q. How is your testimony organized?**

A. My testimony is organized as follows.

- In Section II, I summarize my testimony.
- In Section III, I discuss the methods to estimate the various components of the allocated cost of service study.
- In Section IV, I describe the resulting revenue targets by rate class and how they compare with revenues for the test year.
- In Section V, I discuss the main conclusions.

## II. SUMMARY OF TESTIMONY

**Q. Please summarize your direct testimony on the allocated cost of service study.**

A. PSNH's ACOSS is intended to identify the relative responsibility of each rate classification for the recovery of the overall costs of distribution service in the test year, 2018. The ACOSS determines the overall rate of return overall and by rate class and the degree of over/under recovery of allocated costs under existing tariffs. Thus, it indicates the changes to present rates that would be necessary to result in equal rates of return on rate base for each class. Any rate class paying less than this cost allocation is assumed to be cross-subsidized by other classes based pm the ACOSS approach. In practice, the Company is expected to use the ACOSS results as a guide, but in a manner that recognizes customer impact considerations.

The 2019 study begins with the review of the Company's proposed distribution revenue requirement (operating expenses, net plant, taxes, depreciation, etc.) for the test year ending December 31, 2018. Two versions were computed, an adjusted "per books" test year, and a proforma test year.

The ACOSS develops cost allocation factors for the different components of plant and expenses using each rate class' share of various measures of demand, from load research provided by the Company, and test-year customer numbers, as well as from weighting factors as applicable to meter costs, and customer-related expenses. Under the ACOSS method, customers are assumed to be responsible for a share of the sunk, historical demand-related costs in proportion to kW of coincident and non-coincident demand by class, customer numbers, weighted expenses by class and other cost drivers. A discussion of these results is provided in Section IV of my testimony.

## III. METHODS USED IN PSNH'S ACOSS

**Q. How are the various distribution plant costs classified in the ACOSS?**

A. The study distinguishes between demand-related and customer-related costs. Distribution station plant (account 362) is considered in its entirety as demand-related. Transformers, including step transformers and service transformers (Account 368), as well as the underground and overhead circuits (Accounts 365, 366, and 367), are considered to have both a demand and a customer-related component. The split of these accounts is based on the results of the Company's Minimum System ("MS") Study. Meters, service drops and installations on customer premises, are considered to be entirely customer-related, and allocated on the basis of both relative differences in installed costs and customer numbers.

**Q. Would you please describe the minimum system study and the resulting classification factors?**

A. The MS study involves the following steps (also described on pages 90-92 of the NARUC manual):

- Step 1: Determine the minimum sized conductor, transformer and service is installed on the distribution system.
- Step 2: Determine the installed cost per unit for the minimum sized plant. Installed costs include material costs, labor costs and equipment costs.
- Step 3: Multiply the cost per unit of the minimum sized plant by the total inventory of each plant type.
- Step 4: The total cost of the minimum sized plant is divided by the total cost of the actual sized distribution plant in the field. This ratio is deemed to be the customer-related portion of distribution plant investment, with the balance being the capacity-related portion.

Table 1 below indicates the percent of distribution plant classified as customer and demand-related as per the results of the MS method.

**Table 1. Minimum System Study Classification Factors**

| Account | Demand | Customer |
|---|---|---|
| 364 POLES - PRIMARY | 23.5% | 76.5% |
| 364 POLES - SECONDARY | 16.9% | 83.1% |
| | | |
| 365 PRIMARY OH LINES | 59.2% | 40.8% |
| 365 SECONDARY OH LINES | 66.1% | 33.9% |
| | | |
| 366 PRIMARY UG LINES 1-PH | 82.3% | 17.7% |
| 366 PRIMARY UG LINES 3-PH | 92.8% | 7.2% |
| 366 SECONDARY UG LINES | 58.4% | 41.6% |
| 367 PRIMARY UG LINES 1-PH | 82.3% | 17.7% |
| 367 PRIMARY UG LINES 3-PH | 92.8% | 7.2% |
| 366 SECONDARY UG LINES | 58.4% | 41.6% |
| | | |
| 368 OH TRANSFORMERS | 17.6% | 82.4% |
| 368 UG TRANSFORMERS | 78.9% | 21.1% |

**Q. How do you allocate the demand-related costs of transformers and conductors?**

A. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads, and so customer-class non-coincident peak demands ("NCP"), or even individual customer maximum demands are suitable to allocate the demand component of distribution facilities. PSNH's ACOSS uses class NCP to reflect the ratio of the class's maximum demand in the year compared to the sum of all the classes' highest annual demands, irrespective of when those demands occur. Class NCP allocators take into account the diversification of loads at the rate class level.

Q. **Have you made any changes with regard to the allocation method for other demand-related costs as compared to the Company's allocated cost study filed in the 2009 rate case?**

A. Yes. I have made several changes with regard to station accounts 360-362. The 2019 ACOSS distinguishes between the elements of distribution plant that are installed to meet loads during the highest system peak hours in the year, such as the case of bulk distribution substations, and investments that are driven by less diversified demands, such as conductors and transformers. The 2019 study employs a combined or hybrid allocator for the allocation of distribution substation plant account that takes into account both the class contribution to the top 20 distribution system coincident peak hours in the test year, and class NCP demands. This is a departure from the method employed by PSNH in previous studies, which relied entirely on class NCP for all demand-related distribution plant. NCP-based allocators are less likely to reflect cost causation with regard to distribution substations, which must have sufficient capacity to meet the distribution station coincident peak demands, not the sum of non-coincident demands by rate class. Thus, a hybrid allocator for this element of plant does a better job at reflecting cost causation than just relying on class NCP.

**Q. How did you determine the hybrid class allocator for station plant?**

A. The first step was to determine what portion of the substation plant account represents bulk stations versus lower voltage distribution substations. Although both types of distribution substations may peak at the time of (or close to) the system coincident peak, the bulk stations are more likely to do so, according to my review of hourly loads at individual bulk stations. Hourly load data at the lower voltage substation was not available to be able to determine their coincidence factors. A pure 20CP allocator would have not assigned any cost responsibility to classes that only contribute to the winter peak. A very small percentage of PSNH's stations peak in the winter. A class NCP allocation approach is useful to recognize that not all elements of the distribution system experience their peak load at a time coincident with the system peak and give a greater cost responsibility to rate classes that peak outside that peak. I determined that 53 percent of account 362 (and associated operation and maintenance expenses) should be allocated to customer classes on the basis of their contribution to the average of the 20 hours of maximum system demand (20CP) and 47 percent on the basis of class NCP. This split was based on the relative total replacement costs of bulk stations vs. non-bulk substations.

**Q. Why did the study rely on 20 peak hours as opposed to single peak?**

A. In order to recognize that there is more than one coincident peak hour that the utility would consider for planning purposes, the allocator uses the highest 20 coincident station peak hours as opposed to a single coincident peak hour. This is also consistent with assuming five days of critical peak demands in the summer, with four critical hours on average in each day. A review of the system distribution retail and wholesale hourly loads the test year (excluding the loads of transmission customers) revealed that 2018 had high peak loads within 95 percent of the highest summer peak load for four days in August and one day in July, and at least three sequential hours of sustained peaks in those days. These hours were used to identify the top 20 hours.

**Q. Does the new method to allocate station plant have a major impact on the allocated costs as compared to class NCP?**

A. I compared the new system-coincident method for station plant with the older NCP approach. There are differences of less than 1 percent for the Residential and General Service rates. The classes that are less coincident with system peak, such as water heater rates for both residential and general service customers, general service space heating rate, and street lighting rates OL and EOL receive a lower allocation of station plant as compared to a pure NCP method. The new result is, however, more aligned with cost causation for these rates than the method employed in the past. For example, in the case of street lighting, their usage does not impact the high voltage distribution system, because they are only turned after the peak hours in the summer season. This means that the distribution planners do not need to take streetlight usage into account when deciding how much capacity is needed at a given substation. The only exceptions are those streetlights located in areas served by substations that peak in the winter months. At the moment, those substations only represent approximately 10 percent of the entire system load in PSNH's system.

**Q. What changes have you introduced in the context of allocating costs of distribution plant, other than station?**

A. The prior study adopted the results of the MS Study combining single-phase and multi-phase equipment. Customers who do not receive service off the single-phase primary distribution system should not pay the costs of this part of the distribution system. Thus, the 2019 ACOSS uses separate classification factors for single phase versus three-phase wherever separate accounting cost information is available, to avoid allocating costs to three-phase customers of equipment that they do not use. I relied on the split on miles of single-phase and multi-phase distribution plant and their associated replacement cost (in dollars per mile) to establish a separation of accounts within primary lines (accounts 366 and 367). I also created distribution line cost allocators to account for the differing usage of the single-phase portions of the system by different customer classes, based on the information provided by the Company regarding the number of 3-phase customers within the General Service Rate. All GV and LG customers are three-phase customers. This separation was only possible for accounts 366 and 367, since the inventory in other accounts was not detailed enough to identify the phase of the conductor.

**Q. How did the ACOSS account for the fact that large commercial customers own their own transformers?**

A. The allocation of demand-related costs in Account 368 uses an adjusted class NCP allocation factor to exclude the share of NCP associated with customers in GV and LG rates who are served from customer-owned transformers. All other customers in classes GV and LG rent a transformer from the company. This adjustment relied on a review of transformer ratings owned by these customers, compared to the rating of the total transformers dedicated to the class (customer-owned plus rented transformer). The share of customer-owned transformer ratings was assumed to represent the share of the class NCP associated with the customer-owned transformers. The revenue from rental of transformers (account 454) is applied to the classes GV and LG as corresponds based on the test-year rental payments by these classes.

**Q. Do you see any limitations in the allocation factors for distribution plant and expenses?**

A. There are limitations in the precision of the ACOSS allocators, but these are inherent to any allocated cost study that relies on limited granularity in accounting cost records. For example, the transformer plant, in account 368, does not distinguish between the primary step transformers, which convert power voltage down to a lower level but do not directly connect customers' premises to the grid, and the service line or secondary transformers, which directly connect customer premises to the grid. The former are built based on more diversified demands and could arguably be allocated on the basis of the hybrid approach, just like the lower voltage distribution costs. The service transformers need to attend to the more local demands of the customers connected to them. Likewise, given the limitations of accounting data, there was not enough detail to isolate the costs of trunk-line, upstream primary feeders from the rest of plant in accounts 365-367. Upstream feeders are driven by coincident peak demands at the substation. The study allocates all demand-related costs of accounts 365-367 and all demand-related costs of account 368 on the basis of class NCP. Lastly, another limitation has to do with the customers served at the 34.5 kV voltage level. These customers should not need to pay for the cost of lower voltage systems, but the accounting records do not distinguish by voltage level other than primary and secondary. Again, this is a common limitation in ACOSS allocation methods when only aggregated plant account records are available.

**Q. How does the ACOSS allocate customer-related plant and expenses to customer classes?**

A. Customer-related costs vary with the number and type of customers. When customers are added, the Company faces higher costs for customer service expenses such as meter reading, collection and inspection, billing, and bad debts. New meter and service drops are also installed. Relative weights were estimated to reflect differences in the effort required and the cost incurred to provide customer services to individual customers in each rate class. Examples of customer allocators are as follows:

- Meter reading allocation factors were based on number of meter reads and average cost per read, by class, as provided by the Company;
- Allocation factors for the meter plant were based on the relative ratios of the average installed meter cost within a class; with the relative weight of a residential customer set equal to one, each of the other classes is assigned weighting factors. The ratios of the weighted customer counts for each class to the total weighted number of customers provides the customer allocation factor.
- Collection expenses were allocated to residential and general service based on the number of customers in these categories and average per-customer cost by class.
- Bad debts and other customer accounts expenses were allocated on the basis of the review of accounts by the Company on the relative amount of these expenses by class.

- Customer service and informational expenses (accounts 908 and 910) were assigned to rates GV and LG only.

The specific costs associated with streetlights (such as luminaires, ballasts, light bulbs and other equipment necessary for street lighting, including an allocated share of general plant) were allocated directly to the streetlight class OL. These are accounts 371 and 373.

**Q. How does the ACOSS treat load control service customers?**

A. These customers do not have separate treatment in the ACOSS because the Company does not have the curtailment rights for distribution reliability reasons. Therefore, the peak demand of these customers is considered in full when determining the demand-related cost allocations.

**Q. How does the ACOSS treat the customers of standby Rate B?**

A. Standby rate customers should not be treated differently in the ACOSS because in theory they should pay the same as full requirements customers in the otherwise applicable rate, as long as they impose the same costs on the system. The ACOSS uses the same allocator type as the rest of the classes, i.e., the 20CP/NCP allocator station plant and class NCP for other demand-related costs. This are based on records of actual non-coincident back-up demands of the customers GV-B and LG-B.

**Q. How does the ACOSS treat streetlighting rates?**

A. The study assigns costs to streetlighting using an equivalent customer-method that assumes that street light fixtures will require a share of the transformer in proportion to its monthly usage, i.e., a fixture would require a specific kW of transformer capacity equal to 10 percent of the capacity required by a residential customer assuming that the fixture monthly usage is 10 percent of the average residential customer. While this is imprecise, it is a second-best solution given the lack of information as to how many fixtures are connected to the same transformer on an average, system-wide basis in the service territory.

## IV. RESULTS OF REVENUE TARGETS BY CLASS

**Q. What does the ACOSS determine in terms of the adequacy of current distribution rate levels?**

A. The results of the 2019 ACOSS demonstrate that PSNH's existing distribution rates are inadequate to allow the Company to recover the test year cost of providing electric distribution service in New Hampshire with a reasonable rate of return on its electric property used and useful. PSNH is currently requesting an overall revenue requirement increase for distribution rates of approximately 20 percent, which would provide an overall return on rate base of 7.62 percent in the proforma test year version. The overall earned rate of return that the Company currently obtains from current rates is 3.45 percent, which is less than half of the target return. With regard to the realized return on rate base by class, the ACOSS proforma results show very divergent class rates of return at current rates. Other that General Service customers and Large General Service customers, all other classes are either paying significantly less or significantly more than their proportional share of allocated costs. Figure 1 below illustrates the earned returns by rate class. Both residential LCS and general service LCS test-year revenues provide a negative return on allocated rate base. The combined Residential & Residential TOD provide almost no return, as well as the residential Water Heating rate. By contrast, all other commercial, industrial, and streetlighting classes currently provide above average returns.

**<u>Figure 1. Realized Rate of Return by Rate Class at Current Revenues</u>**

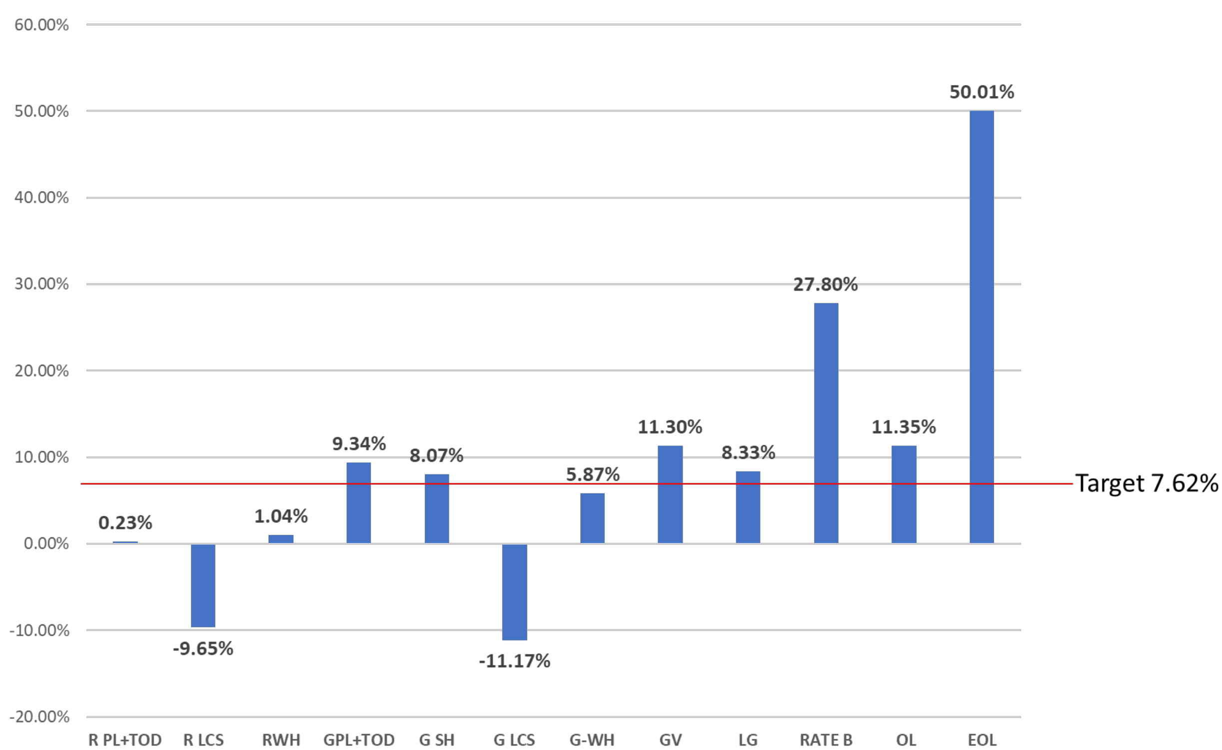


Table 2 below provides a summary of the pro forma test year ACOSS target revenue requirement results at the class level. Table 3 provides the same information for the "Per book" test year. The detailed 2019 ACOSS output is included in Attachment ACOSS-2.

As shown in the proforma test year, the rate classes that would need to experience a significantly larger than average percent increase to achieve the Company target rate of return of 7.62 percent are the residential rates RPL+TOD, residential and general service

LCS, residential water heating, and General service LCS. The residential customers are paying about 29 percent less than their proforma revenue target. This class makes up about 66 percent of the overall rate base. Thus, bringing all rate classes to parity after netting out other revenues would require a significant percent increase for the standard residential rate (about 41.2%). This is generally consistent with the results of the MCOSS for the Residential class. The General Service rate (combined G P&L and G TOD) customers are contributing by more than the average required return and would see a decrease of about 6.5 percent. Rates GV and LG would also be reduced by 14 percent and 3 percent, respectively. In the case of street lighting, both rates OL and EOL appear to be over-recovering and would need to be reduced by about 10 percent and 51 percent, respectively.

**Table 2: Distribution Revenue Requirement and Required Rate Change**
**Proforma for Test Year 2018**

| Description | Test Year 12/31/2018 Proforma | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate base | 1,215,668 | 796,079 | 4,228 | 15,186 | 226,652 | 576 | 380 | 392 | 100,105 | 57,956 | 2,458 | 8,965 | 2,690 |
| Operating income | 41,945 | 1,804 | (408) | 158 | 21,180 | 47 | (42) | 23 | 11,309 | 4,829 | 683 | 1,017 | 1,345 |
| Earned rate of return | 3.45% | 0.2% | -9.7% | 1.0% | 9.3% | 8.1% | -11.2% | 5.9% | 11.3% | 8.3% | 27.8% | 11.3% | 50.0% |
| Requested rate of return/cost of capital | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% |
| Required operating income | 92,590 | 60,633 | 322 | 1,157 | 17,263 | 44 | 29 | 30 | 7,624 | 4,414 | 187 | 683 | 205 |
| **Revenue increase/(decrease)** | **69,913** | **81,209** | **1,008** | **1,378** | **(5,408)** | **(4)** | **99** | **9** | **(5,086)** | **(572)** | **(685)** | **(462)** | **(1,574)** |
| Distribution Revenue Requirement | $ 436,203 | $ 288,050 | $ 1,476 | $ 5,628 | $ 80,338 | $ 201 | $ 129 | $ 148 | $ 34,447 | $ 19,376 | $ 831 | $ 4,062 | $ 1,518 |
| Other Revenue | 16,428 | $ 9,810 | $ 22 | $ 62 | $ 1,945 | $ 3 | $ 2 | $ 2 | $ 3,384 | $ 1,134 | $ 27 | $ 22 | $ 16 |
| **Net Distribution Revenue Requirement** | **419,775** | **$ 278,239** | **$ 1,455** | **$ 5,567** | **$ 78,393** | **$ 198** | **$ 127** | **$ 146** | **$ 31,063** | **$ 18,242** | **$ 804** | **$ 4,040** | **$ 1,502** |
| Current Distribution Revenues | 349,862 | $ 197,030 | $ 447 | $ 4,188 | $ 83,801 | $ 201 | $ 29 | $ 137 | $ 36,149 | $ 18,814 | $ 1,489 | $ 4,501 | $ 3,077 |
| **Required Change in Rates** | **19.98%** | 41.22% | 225.63% | 32.91% | -6.45% | -1.79% | 341.80% | 6.91% | -14.070% | -3.042% | -46.01% | -10.25% | -51.18% |

**Table 3: Distribution Revenue Requirement and Required Rate Change by Rate Class**
**Adjusted Per Book, Test Year 2018**

| Description | Test Year 12/31/2018 Per Book | R PL+TOD | R LCS | RWH | GPL+TOD | G SH |
|---|---|---|---|---|---|---|
| Rate base | 1,219,367 | 798,527 | 4,241 | 15,226 | 227,341 | 578 |
| Operating income | 53,752 | 9,987 | (369) | 320 | 23,284 | 51 |
| Earned rate of return | 4.41% | 1.3% | -8.7% | 2.1% | 10.2% | 8.9% |
| Requested rate of return/cost of capital | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% |
| Required operating income | 86,346 | 56,545 | 300 | 1,078 | 16,098 | 41 |
| **Revenue increase/(decrease)** | **45,092** | **64,410** | **926** | **1,049** | **(9,941)** | **(14)** |
| Distribution Revenue Requirement | $ 410,714 | $ 270,667 | $ 1,394 | $ 5,299 | $ 75,727 | $ 190 |
| Other Revenue | 15,760 | $ 9,227 | $ 21 | $ 62 | $ 1,867 | $ 3 |
| **Net Distribution Revenue Requirement** | **394,954** | **$ 261,440** | **$ 1,373** | **$ 5,237** | **$ 73,860** | **$ 187** |
| Current Distribution Revenues | 349,862 | $ 197,030 | $ 447 | $ 4,188 | $ 83,801 | $ 201 |
| **Required Change in Rates** | **12.89%** | 32.69% | 207.35% | 25.05% | -11.86% | -7.19% |

| Description | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|
| Rate base | 381 | 393 | 100,411 | 58,139 | 2,466 | 8,977 | 2,686 |
| Operating income | (39) | 27 | 12,012 | 5,189 | 696 | 1,195 | 1,398 |
| Earned rate of return | -10.3% | 7.0% | 12.0% | 8.9% | 28.2% | 13.3% | 52.1% |
| Requested rate of return/cost of capital | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% |
| Required operating income | 27 | 28 | 7,110 | 4,117 | 175 | 636 | 190 |
| **Revenue increase/(decrease)** | **92** | **1** | **(6,781)** | **(1,483)** | **(721)** | **(774)** | **(1,671)** |
| Distribution Revenue Requirement | $ 123 | $ 139 | $ 32,748 | $ 18,464 | $ 795 | $ 3,749 | $ 1,421 |
| Other Revenue | $ 2 | $ 2 | $ 3,380 | $ 1,134 | $ 27 | $ 22 | $ 15 |
| **Net Distribution Revenue Requirement** | **$ 120** | **$ 137** | **$ 29,368** | **$ 17,331** | **$ 768** | **$ 3,727** | **$ 1,405** |
| Current Distribution Revenues | $ 29 | $ 137 | $ 36,149 | $ 18,814 | $ 1,489 | $ 4,501 | $ 3,077 |
| **Required Change in Rates** | 318.13% | 0.39% | -18.759% | -7.884% | -48.42% | -17.20% | -54.32% |

## V. CONCLUSION ON ACOSS AND USE OF RESULTS

**Q. Is the ACOSS a good reference to set efficient price signals?**

A. An allocated cost of service study does not serve economic efficiency goals such as optimizing the use of the system. It is not a reasonable basis to determine which costs should be recovered in the per-kWh charge versus the fixed charge. Allocated cost studies are commonly relied upon as a guide to set revenue targets but are rarely used to inform the levels of specific rate components. One of the key differences between the ACOSS and MCOSS is the share of costs that each study considers to be customer-related versus demand-related. In the ACOSS for the test year, residential customer-related costs represent about 63 percent of the residential revenue requirement, with 26 percent considered to be related to non-coincident demand and 26 percent related to coincident peak demand. This would translate to a customer charge of $31.24, assuming that the rate is increased to provide the average required rate of return. The ACOSS is more likely to be used to justify higher demand or kWh charges as compared to a marginal cost-based rate design method. Even if the ACOSS method used similar allocators as the MCOSS, a lower than optimal proportion of costs would get classified as customer or fixed kW-related costs particularly in the current context of slow demand growth and lower need for peak-load related investments. For a broader discussion of rate designs that meet efficiency and equity rate objectives, please refer to my direct testimony on marginal costs.

**Q. What is your overall conclusion about the ACOSS results?**

A. I have developed an allocated cost of service study that relies on best practice methods, subject to the limitations in the granularity of the accounting costs and keeping in mind the need for gradualism. The study demonstrates that rates are currently out of line with best practice ACOSS methods and need to be realigned, taking into account avoidance of rate shock, after considering the weight of the distribution rate in the overall customer bill.

**Q. Does this conclude your testimony?**

A. Yes.

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Amparo Nieto is an energy economist with over twenty years of energy industry experience. She provides advice to utilities, independent system operators and energy regulatory commissions as they address complex regulatory challenges involving pricing, economic, and market design issues. Her consulting engagements involve entities and regulators in the US, Canada, Latin America, Europe, Oceania, and the Caribbean.

In the US, Ms. Nieto has directed an extensive number of energy regulatory projects involving major utilities in California, Nevada and Oregon, as well as utilities in NYISO, MISO, PJM, SPP and ERCOT. She has provided expert testimony before state public utility commissions on behalf of energy utilities on electricity and natural gas marginal cost analysis, electricity rate structures, reforms to tariffs for customers with distributed generation, evaluation of net metering and efficient power contract design. She has developed cost-benefit analysis of utility demand response programs, interruptible rates, and smart rates.

Ms. Nieto has authored expert reports on electricity sector restructuring policies and wholesale energy market design in Europe and Latin America. She has advised energy regulators and independent transmission operators in the US and Alberta on transmission planning, cost allocation, and planning reserve margin analysis. Ms. Nieto involved in the implementation of default service auctions on behalf of utilities in Illinois, Pennsylvania and Spain, as well as on the design of renewable resources in Mexico.

Ms. Nieto directs the Utility of the Future Rates Group (UFRG), a membership-based utility working group attended by senior executives from North American energy utilities. The group provides a forum for discussion of innovative rates, cost analyses and regulatory reforms to adapt to the expansion of distributed energy resources. For over ten years, she has conducted seminars on electricity marginal cost of service methods and best practice electricity ratemaking. These seminars were attended by energy utilities and state commissions from the US and overseas.

Ms. Nieto has published energy papers in The Electricity Journal and frequently speaks on energy regulatory topics at various industry forums.

## Professional Experience

**Economists Incorporated** (San Francisco)

Senior Vice President — Dec 2017 – present

Economists INCORPORATED

**NERA Economic Consulting**

| | |
|---|---|
| Associate Director / Vice President (Los Angeles) | 2000 – 2017 |
| Consultant (Madrid, Spain) | 1997 - 1999 |

## Education

**Master's Degree in Economics,** Institute for Fiscal Studies, Madrid, Spain

Advanced microeconomics, macroeconomics, econometrics and micro-econometrics, public policy and optimal fiscal theory.

**B.A., Economics (Honors)**, University of Carlos III, Madrid, Spain

Concentration on microeconomics, competition and industrial economics, financial analysis, econometrics.

## Selected Consulting Assignments

***Renewable Energy Resources***

City of Palo Alto, California. Development of pricing schemes for renewable-based microgrids.

Ministry of Energy (SENER), Mexico: Advisor to SENER regarding the development of a procurement auction to procure multiple renewable technologies across a variety of time-frames.

Iberdrola, California, US. Reviewed long-term forecasts of fuel costs, energy market conditions, and regulatory policy to assess the potential growth outlook for wind and solar generation resources in California over a 20-year horizon.

Regulatory Office for Network Industries (RONI), Slovakia. Directed the team that assisted the Slovakian regulatory commission on the design of efficient support mechanisms for renewable energy sources and a reliable system of issuing guarantees of origin for RES. Trained the commission staff on best practice RES regulation.

Illinois Power Agency (IPA), US. Assessment of parameters and benchmark analysis for Solar Renewable Energy Credits (SRECs) in the context of the auction held by Ameren Illinois Company and Commonwealth Edison to procure RECs from solar distributed generation resources.

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Southern California Edison, Los Angeles, California, US. Member of the team that advised the utility's Supply Group on improvements to the mechanism for contracting with renewable generation resources.

***Electricity Cost Studies, Rate Design, Pricing for Distributed Energy Resources***

Various North American Electric Utilities, 2000 – present. Advised and testified on the development of electricity marginal cost studies, analysis of the value of new demand response rates, solar PV, customer contracts, design of time of use electricity tariffs, standby rates. Examples of utility clients include:

- Central Maine Power Company, Maine
- Eversource Energy, New Hampshire
- Rochester Gas and Electric, New York
- New York Service Electric and Gas, New York
- Sierra Pacific Power Company and Nevada Power d/a/a NV Energy, Nevada
- Sacramento Municipal Utility District (SMUD), California
- Los Angeles Department of Water and Power (LADWP), California
- Salt River Project (SRP), Arizona
- Con Edison, New York
- Otter Tail Power (OTP), Minnesota, North Dakota, South Dakota
- Xcel Energy, Minnesota
- MidAmerican Energy Company, Iowa
- Eugene Water and Electric Board, Oregon
- Iberdrola, Spain
- NB Power, New Brunswick, Canada
- Manitoba Hydro, Manitoba, Canada
- BC Hydro, British Columbia, Canada
- Newfoundland Labrador & Hydro, Newfoundland, Canada

Avangrid, New York. Advised in setting the basis and workplan to develop a locational distribution marginal cost study, to be used for a compensation of Distributed Energy Resources (DERs), as directed by the Commission VDER Order within the Reforming the Energy Vision (REV) proceeding.

Southern Company, US. Reviewed the company's proposed approach to undertake loss of load expectation analysis and recommended improvements. Provided guidance to develop capacity cost allocation factors for demand response programs and new customer evaluation.

NB Power, New Brunswick, Canada. Recommended approach to estimate the incremental costs to the utility when customers opt-out of smart metering, taking into account the pace of smart meter deployment plans. Provided rate design recommendations in the light of smart grid investments.

Abu Dhabi, UEA. Advised on the reform of distribution rates and suitable mechanism to undertake cost allocation based on marginal costs. Proposed revision to existing electricity cross-subsidies.

Electricity Regulatory Board (ERB), Kenya, Africa. Co-authored an Electricity Tariff Policy for ERB, aimed at improving the financial health of the sector and promoting the efficient expansion of electricity service. Developed financial models for calculation of utility revenue requirement and provided on-site training to the ERB staff. Designed the pricing terms of a new sample Power Purchase Agreement between the incumbent generator (KenGen) and the distribution utility (KPLC).

Barbados Federal Trade Commission, Barbados. Directed the team advising the Barbados energy regulatory commission during Barbados Power and Light (BP&L)'s rate application. Assessed the utility's estimated cost of capital and revenue requirement, the embedded and marginal electricity cost methods used by the utility to allocate costs to customer classes and time of use rate proposals.

Iberdrola, Spain. Member of the energy practice team advising a large Spanish electric utility regarding its regulatory strategy in preparation for the restructuring of the electricity sector in Spain as well as general advise in a broad range of regulatory issues involving retail access, stranded cost analysis and open access tariffs. Participated in industry working groups in charge of proposing detailed policy rules.

***Wholesale Market Design, Competition Analysis***

Analysis of utility mergers, various utilities, US. Review the competitive impact on electricity markets of a number of proposed utility mergers. Analyzed potential horizontal and vertical market power impacts.

Commission for Energy Regulatory of Ireland, Ireland: Member of the market design team for the all-island electricity market. Design of options for a Capacity Payment Mechanism on the island of Ireland that would be viable and sensible in the context of the Irish electricity market.

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Independent System Operator (ISO) of New England, US. Advised the ISO-NE on revisions to ISO's Forward Capacity Market (FCM), with regard to the *Alternative Capacity Price Rule.*

Ministry of Energy, Argentina. Comprehensive review of the Argentine wholesale electricity market and their impact on competition. Recommended revisions to market rules.

PECO Energy Company, Pennsylvania, US. Manager of the Independent Evaluator team that administered the Default Service Supply auctions on behalf of PECO Energy Company. Prepared assessment report evaluating the competitiveness of the auction and results for the Commission's review.

First Energy, Philadelphia, US. Administered Default Service Supply solicitations via a descending-clock auction on behalf of Met-Ed and Penelec utilities in Pennsylvania. Authored the report evaluating the competitiveness of the auction and results for the Commission's review.

Spanish National Energy Commission (CNE), Madrid, Spain. Administered the default service electricity supply ("CESUR") auctions on behalf of the large distribution companies in Spain and Portugal. Assessed the bidders' competitive behavior and prepared an assessment report. Advised the Commission during the discussions that led to major energy sector restructuring legislation.

***Incentive-Based Regulation of Distribution Networks***

UK Energy Networks Association, UK. Advisor to the Association on evaluating a potential reform of electricity distribution network planning standards to account for new developments, such as the emergence of smart grids and distributed resources.

Grid Australia, Sydney, Australia. Advisory services regarding Performance-Based Regulation (PBR) methods for electricity network.

Edison Electric Institute (EEI), US. Co-author of report "Making a Business of Energy Efficiency: Sustainable Business Models for Utilities". A report on incentive mechanisms to achieve utility goals for energy efficiency and demand response.

Various utilities, USA. Provided assessment of impact of solar distributed generation on the utility's avoided costs and net revenues. Recommended or evaluated revisions to tariff structures to avoid large cost shifting among customers and inequity concerns.

***Transmission Planning and Cost Allocation***

Australian Energy Market Commission, Australia. Critiqued the proposed revisions to the electricity market rules in Australia regarding firm transmission access and rights. Analyzed the suitability of Financial Transmission Rights, or their equivalent, for the

Australian market. Conducted a survey of international transmission planning and cost-allocation methodologies in an earlier assignment.

TransGrid, Australia. Reviewed transmission planning and pricing policies, including arrangements to introduce competitive solicitations and non-wires alternatives in long-term transmission planning.

Alberta Electric System Operator (AESO), Calgary, Alberta. Analyzed AESO's cost study and recommended revisions to improve transmission tariffs and cost allocation approach.

Commission for Energy Regulatory of Ireland, Ireland. Participated in the drafting of the all-island electricity market rules and recommended changes to the Transmission Use of System (TUoS) charges for the Republic of Ireland.

NYISO, New York, US. Provided recommendations to the New York Independent System Operator for a reform of their Black Start service compensation mechanism as part of the ISO Tariff.

## SELECTED TESTIMONIES AND EXPERT REPORTS

"Otter Tail Power Company's Marginal Cost of Generation, Transmission and Distribution Service, Final Report." February 16, 2018. Report submitted to support OTP's 2018 South Dakota electricity rate case.

"Otter Tail Power Company's Marginal Cost of Generation, Transmission and Distribution Service, Final Report." November, 2017. Report submitted to support OTP's 2018 North Dakota electricity rate case.

"Central Maine Power Company's Marginal Cost of Electricity Distribution Service, Final Report." October 30, 2017. Study report submitted in preparation of CMP's 2018 distribution rate case.

Expert Report: "A Review of Southern Company's Generation Reserve Margin Methodology and Capacity Worth Factor Approach". Prepared for Southern Company, October 9, 2017.

Expert Report, SRP's Board of Directors: "Review of Salt River Project's Electricity Marginal Cost of Service Study and Proposed Rates for Net Metering Customers", August 2017.

Expert Report: "Review of Sacramento Municipal Utility District's Marginal Cost Study and Proposed Design of Residential Time of Use Rates". November 27, 2016.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony: "Marginal Costs, Revenue Reconciliation and Rate Design for Net Metering Customers", In the Matter of

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the Application of Sierra Pacific Power Company d/a/a NV Energy for Authority to Reform Rates for Electric Utility Service in 2016 General Rate Case. October 31, 2016

Before the Public Utilities Commission of the State of Minnesota, Rebuttal Testimony: "Fixed Charges, Marginal Cost Study and Rate Design Policy", In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota, September 12, 2016.

Salt River Project vs. Solar City, Law Suit, US. Deposition testimony regarding expert report and analysis of SRP's rate reform for solar customers. August 2016.

Before the Public Utilities Commission of the State of Minnesota, Testimony: "Fixed Charges and Rate Design Policy", In the Matter of the Rate Application of Otter Tail Power Company in Minnesota, February 2016.

Before the Modesto Irrigation District Board of Directors, expert presentation: "Review of MID's Solar PV Cost-Shifting Analysis", California, April 2016.

Expert Report: "Assessment of Otter Tail Power Company's Interruptible Rate Portfolio and Development of Dynamic Rates", prepared for Otter Tail Power Co. November 2015.

Before the New York State Public Service Commission, Direct Testimony: "Rochester Gas & Electric Corporation Electricity and Natural Gas Marginal Cost of Service Studies", June 2015.

Before the New York State Public Service Commission, Direct Testimony: "New York State Electric and Gas Electricity and Natural Gas Marginal Cost of Service Studies", June 2015.

Before the Salt River Project Board of Directors, Testimony: "Review of SRP Proposed Residential Customer Generation Price Plan", February 2015.

Before the State of North Carolina Utilities Commission, Testimony: "Review of Alternative Application of the Peaker Method Proposed by EPCOR USA North Carolina LLC with respect to Computation of Avoided Energy and Capacity Costs", July 23, 2010.

Before the New Brunswick Board of Commissioners of Public Utilities, Testimony, with Wayne Olson: "The Role of DSM and Demand Response in Load Forecasting and Integrated Resource Planning", on behalf of the New Brunswick Public Intervener, November 9, 2006.

**SELECTED PRESENTATIONS**

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"Examining the Key Pricing Policy Elements of New York's Reforming the Energy Vision", presented at the 31st Annual Western Conference (CRRI), Monterey, California, June 28, 2018.

"Estimating the Value of Distributed Energy Resources and Implications for Rates", presented at the California Municipal Utility Rates Group, May 2018.

"Marginal Cost Methods and Efficient Rate Design", presented at the Utility of the Future Rates Group, San Francisco, California, April 2018.

"Value-Based Tariff Model for Distributed Energy Resources: Principles and Framework Options". Presented at 30th Annual Western Conference (CRRI), Monterey, California, June 28, 2017.

"Regulatory Incentive Methods for Electricity Distributors: Emerging Trends", with Richard Druce. Presented at Rutgers University's 29th Annual Western Conference (CRRI), Monterey, California, June 23, 2016.

"Renewable Microgrids: Getting the Pricing Right". Presented at the Marginal Cost Working Group (MCWG), Washington, D.C., May 5, 2016.

"Policy Options to Address Cross Subsidies from Self-Generation". Presented at the 12th Annual National Law Seminars International Conference on Electric Utility Ratemaking, Las Vegas, Nevada, March 14, 2016.

"Demand Charges and their Role in Net Energy Metering". Presented at the "Residential Demand Charges Symposium", EUCI, Calgary, Canada, December 1, 2015.

"Utility Regulation in the Era of Distributed Renewables: Is There a Need for a New Business Model?". Presented at Rutgers University's 28th Annual Western Conference (CRRI), Monterey, California, June 26, 2015.

"Solar Distributed Generation and Rate Restructuring". Presented at the California Municipal Rates Group (CMRG), Sacramento, California, May 18, 2015.

"Integrating Renewable Resources through Capacity Markets: The Case of California". Presented at Law Seminars International's Energy in California Conference, San Francisco, California, September 16, 2014.

"Rate Design Options to Deal with Solar Net Metering Concerns". Presented at the California Municipal Rates Group (CMRG), Sacramento, California, April 25, 2014.

"Capacity Markets Put to the Test: New Approaches to Meet Evolving Reliability Needs". Presented at Rutgers University's 27th Annual Western Conference (CRRI), Monterey, California, June 26, 2014.

"Connecting Wholesale and Retail Pricing: A Look at Required Policy and Market Design Decisions". Presented at the Harvard Electricity Policy Group (HEPG), Dana Point, California, March 7, 2013.

"Demand Response and its Role within Wholesale Energy and Capacity Markets". Presented at Rutgers University's 25th Annual Western Conference (CRRI), Monterey, California, June 2012.

"Achieving Efficient Demand Response through Dynamic Rates". Presented at Law Seminars International's Electric Ratemaking Conference, Las Vegas, Nevada, February 9, 2009.

"Critical Peak Pricing: A Marginal Cost Approach". Presented at the Marginal Cost Working Group (MCWG), Phoenix, Arizona, April 2008.

"Electricity Rate Structure Design: Sector Issues in Rate Design, Marginal and Embedded Cost Studies". Delivered at the University of PURC's World Bank International Training Program on Utility Regulation and Strategy, Florida, January 16, 2007.

"Demand Bidding Programs in ISO/RTO Environments". Presented at the Marginal Cost Working Group (MCWG), Austin, Texas, October 12, 2006.

"Responding to EPAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering". Sponsored by Edison Electric Institute, May 2006.

"Locational Generation Capacity Payments in New England". Presented at the Marginal Cost Working Group (MCWG), Albuquerque, New Mexico, April 27, 2005.

"Analysis of the International Experience with Performance Based Regulation". Presented at the Marginal Cost Working Group (MCWG), Nevada, April 3-5, 2000.

## SELECTED ENERGY PUBLICATIONS

"Optimizing Prices for Small-Scale Distributed Generation Resources: A Review of Principles and Design Elements", *The Electricity Journal*, April 2016.

"Wholesale Energy Markets: Setting the Right Framework for Price Responsive Demand". *The Electricity Journal*, December 2012.

"The Role of Demand Response in the Efficiency of Electricity Wholesale Markets". *Papeles de Economía Española,* Madrid. Issue 134, December 2012.

"Locational Electricity Capacity Markets: Alternatives to Restore the Missing Signals". *The Electricity Journal*, Volume 20, March 2007.

"The Line in the Sand: The Shifting Boundary between Markets and Regulation in

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Network Industries." Co-author. NERA book, September 2007.

"Performance-Based Regulation of Electricity Transmission in the US: Goals and Necessary Reforms". NERA's Newsletter *Energy Regulation Insights*, Issue 28, March 2006.

"Analysis of the Electricity Sector in Spain". Utility Regulation in the EU. Privatisation International and Centre for the Study of Regulated Industries (CRI), *Utility Regulation 2000 Series*, Volume 1, June 2000.

**LANGUAGES**

English (fluent), Spanish (fluent)

# PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
# D/B/A EVERSOURCE ENERGY
# ALLOCATED DISTRIBUTION COST OF SERVICE STUDY

## PRO FORMA TEST YEAR 2018

**Permanent Filing**

**May 28, 2019**

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# PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
# D/B/A EVERSOURCE ENERGY
# ALLOCATED DISTRIBUTION COST OF SERVICE STUDY

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**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 1-A. DISTRIBUTION REVENUE REQUIREMENT AND REQUIRED RATE CHANGE BY RATE CLASS**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Line | Description | Reference | Test Year 12/31/2018 Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | Rate base | Table 1B, Line 15 | 1,215,668 | 796,079 | 4,228 | 15,186 | 226,652 | 576 | 380 | 392 | 100,105 | 57,956 | 2,458 | 8,965 | 2,690 |
| 12 | Operating income | Table 1B, Line 36 | 41,945 | 1,804 | (408) | 158 | 21,180 | 47 | (42) | 23 | 11,309 | 4,829 | 683 | 1,017 | 1,345 |
| 14 | Earned rate of return | Table 1B, Line 38 | 3.45% | 0.23% | -9.65% | 1.04% | 9.34% | 8.07% | -11.17% | 5.87% | 11.30% | 8.33% | 27.80% | 11.35% | 50.01% |
| 16 | Requested rate of return/cost of capital | Sch. EHC/TMD-3 | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% |
| 18 | Required operating income | Line 11 x Line 16 | 92,590 | 60,633 | 322 | 1,157 | 17,263 | 44 | 29 | 30 | 7,624 | 4,414 | 187 | 683 | 205 |
| 19 | Income sufficiency/(deficiency) | Line 12 - Line 18 | (50,645) | (58,829) | (730) | (999) | 3,917 | 3 | (71) | (7) | 3,685 | 415 | 496 | 334 | 1,141 |
| 21 | Gross revenue conversion factor | Sch. EHC/TMD-2 | 1.37142 | 1.37142 | 1.37142 | 1.37142 | 1.37142 | 1.37142 | 1.37142 | 1.37142 | 1.37142 | 1.37142 | 1.37142 | 1.37142 | 1.37142 |
| 22 | Revenue increase/(decrease) | Line 19 x Line 21 | 69,456 | 80,679 | 1,001 | 1,369 | (5,372) | (4) | 98 | 9 | (5,053) | (569) | (681) | (459) | (1,564) |
| 24 | Net write-off as a % of retail revenue | Att. EHC/TMD-2, W/P 8 | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% |
| 25 | Uncollectible adjustment | Line 22 x Line 24 | 456 | 530 | 7 | 9 | (35) | (0) | 1 | 0 | (33) | (4) | (4) | (3) | (10) |
| 27 | **Revenue increase/(decrease)** | Ties to Sch. EHC/TMD-1 | **69,913** | **81,209** | **1,008** | **1,378** | **(5,408)** | **(4)** | **99** | **9** | **(5,086)** | **(572)** | **(685)** | **(462)** | **(1,574)** |
| 30 | Distribution Revenue Requirement | Table 5, Line 28 | $ 436,203 | $ 288,050 | $ 1,476 | $ 5,628 | $ 80,338 | $ 201 | $ 129 | $ 148 | $ 34,447 | $ 19,376 | $ 831 | $ 4,062 | $ 1,518 |
| 31 | Other Revenue | Table 5, Line 26 | 16,428 | $ 9,810 | $ 22 | $ 62 | $ 1,945 | $ 3 | $ 2 | $ 2 | $ 3,384 | $ 1,134 | $ 27 | $ 22 | $ 16 |
| 33 | **Net Distribution Revenue Requirement** | Line 30 - Line 31 | **419,775** | **$ 278,239** | **$ 1,455** | **$ 5,567** | **$ 78,393** | **$ 198** | **$ 127** | **$ 146** | **$ 31,063** | **$ 18,242** | **$ 804** | **$ 4,040** | **$ 1,502** |
| 35 | Current Distribution Revenues | Table 5, Line 12 | 349,862 | $ 197,030 | $ 447 | $ 4,188 | $ 83,801 | $ 201 | $ 29 | $ 137 | $ 36,149 | $ 18,814 | $ 1,489 | $ 4,501 | $ 3,077 |
| 37 | **Required Change in Rates** | Line 33 / Line 35 - 1 | **19.98%** | **41.22%** | **225.63%** | **32.91%** | **-6.45%** | **-1.79%** | **341.80%** | **6.91%** | **-14.070%** | **-3.042%** | **-46.01%** | **-10.25%** | **-51.18%** |
| 39 | BREAKDOWN OF REVENUE REQUIREMENT | | | | | | | | | | | | | | |
| 40 | | | **Total** | **R PL+TOD** | **R LCS** | **RWH** | **GPL+TOD** | **G SH** | **G LCS** | **G-WH** | **GV** | **LG** | **RATE B** | **OL** | **EOL** |
| 41 | | Demand-CP | 64,113 | 31,279 | 367 | 764 | 13,485 | 36 | 36 | 23 | 11,055 | 6,725 | 214 | 69 | 59 |
| 42 | | Demand-NCP | 133,017 | 70,215 | 820 | 2,709 | 28,967 | 115 | 77 | 61 | 17,533 | 11,350 | 583 | 315 | 273 |
| 43 | | Customer | 222,645 | 176,745 | 267 | 2,094 | 35,942 | 47 | 15 | 62 | 2,474 | 167 | 7 | 3,656 | 1,170 |
| 44 | | | **419,775** | **278,239** | **1,455** | **5,567** | **78,393** | **198** | **127** | **146** | **31,063** | **18,242** | **804** | **4,040** | **1,502** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 1-B CURRENT AND REQUIRED RETURN ON RATE BASE BY RATE CLASS**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Line | Description | Reference | 12/31/2018 Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | RATE BASE | | | | | | | | | | | | | | |
| 11 | Net Plant | Table 4, Line 16 | 1,568,619 | 1,025,539 | 5,429 | 19,459 | 295,710 | 738 | 488 | 501 | 128,374 | 74,367 | 3,150 | 11,467 | 3,397 |
| 12 | Total Rate Base Deductions | Table 4, Line 24 | (383,078) | (248,816) | (1,297) | (4,648) | (74,889) | (176) | (117) | (120) | (30,846) | (17,859) | (760) | (2,739) | (812) |
| 13 | Total Rate Base Additions | Table 4, Line 32 | 30,126 | 19,356 | 96 | 375 | 5,832 | 14 | 8 | 10 | 2,577 | 1,447 | 69 | 238 | 105 |
| 15 | TOTAL RATE BASE | Sum of Lines 11 to 13 | 1,215,668 | 796,079 | 4,228 | 15,186 | 226,652 | 576 | 380 | 392 | 100,105 | 57,956 | 2,458 | 8,965 | 2,690 |
| 17 | TOTAL OPERATING REVENUE | Table 5, Line 28 | 366,290 | 206,841 | 468 | 4,250 | 85,746 | 204 | 31 | 138 | 39,533 | 19,948 | 1,516 | 4,523 | 3,092 |
| 19 | OPERATION & MAINTENANCE EXPENSE | | | | | | | | | | | | | | |
| 20 | Distr. O&M Expense and misc. Production | Table 6, Line 41 | 81,177 | 50,007 | 305 | 1,146 | 15,300 | 45 | 28 | 29 | 7,933 | 4,790 | 230 | 832 | 531 |
| 21 | Customer Accounting Expenses | Table 7, Line 19 | 22,479 | 18,102 | 35 | 160 | 3,491 | 2 | 2 | 5 | 613 | 52 | 1 | 10 | 7 |
| 22 | Customer Svc. & Information/Sales Expenses | Table 7, Line 26 + Line 33 | 282 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 258 | 21 | 0 | 0 | 0 |
| 23 | Administrative & General Expenses | Table 8, Line 26 | 63,791 | 42,239 | 227 | 932 | 11,819 | 29 | 19 | 25 | 4,907 | 2,604 | 95 | 566 | 328 |
| 24 | Total Depreciation Expense | Table 9, Line 47 | 69,180 | 46,423 | 216 | 887 | 12,850 | 31 | 19 | 23 | 4,652 | 2,643 | 115 | 1,161 | 159 |
| 25 | Total Amortization Expense | Table 9, Line 51 | 19,015 | 12,559 | 64 | 229 | 3,547 | 9 | 6 | 6 | 1,492 | 860 | 36 | 165 | 44 |
| 26 | EESCO Depreciation / Amortization | Table 9, Line 52 | 6,590 | 4,353 | 22 | 79 | 1,229 | 3 | 2 | 2 | 517 | 298 | 13 | 57 | 15 |
| 27 | Property Tax Expense | Table 10, Line 23 | 47,399 | 30,989 | 164 | 588 | 8,936 | 22 | 15 | 15 | 3,879 | 2,247 | 95 | 346 | 103 |
| 28 | Payroll and Other Taxes | Table 10, Line 21 + Line 31 | 5,138 | 3,382 | 18 | 75 | 952 | 2 | 2 | 2 | 401 | 215 | 9 | 50 | 30 |
| 29 | TOTAL EXPENSE BEFORE INCOME TAXES | | 315,051 | 208,056 | 1,052 | 4,095 | 58,125 | 144 | 92 | 108 | 24,652 | 13,730 | 594 | 3,188 | 1,215 |
| 31 | Federal and State Income Taxes | Table 11, Line 48 | 3,227 | (6,986) | (197) | (79) | 5,297 | 11 | (20) | 5 | 3,076 | 1,101 | 225 | 274 | 518 |
| 32 | Deferred Income Tax Expense | Table 11, Line 52 | 6,070 | 3,969 | 21 | 75 | 1,144 | 3 | 2 | 2 | 497 | 288 | 12 | 44 | 13 |
| 33 | Investment Tax Credit | Table 11, Line 53 | (4) | (2) | (0) | (0) | (1) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 34 | OPERATING EXPENSES INCLUDING INCOME TAX | | 324,345 | 205,037 | 876 | 4,092 | 64,566 | 158 | 73 | 115 | 28,224 | 15,119 | 832 | 3,506 | 1,747 |
| 36 | OPERATING INCOME | Line 17 - Line 34 | 41,945 | 1,804 | (408) | 158 | 21,180 | 47 | (42) | 23 | 11,309 | 4,829 | 683 | 1,017 | 1,345 |
| 38 | **REALIZED RETURN ON RATE BASE** | Line 36 / Line 15 | **3.5%** | **0.2%** | **-9.7%** | **1.0%** | **9.3%** | **8.1%** | **-11.2%** | **5.9%** | **11.3%** | **8.3%** | **27.8%** | **11.3%** | **50.0%** |
| 40 | **REQUIRED RETURN ON RATE BASE** | Sch. EHC/TMD-3 | **7.62%** | **7.62%** | **7.62%** | **7.62%** | **7.62%** | **7.62%** | **7.62%** | **7.62%** | **7.62%** | **7.62%** | **7.62%** | **7.62%** | **7.62%** |
| 42 | **REQUIRED OPERATING INCOME** | Line 40 * Line 15 | **92,590** | **60,633** | **322** | **1,157** | **17,263** | **44** | **29** | **30** | **7,624** | **4,414** | **187** | **683** | **205** |

1 **Public Service Company of New Hampshire, d/b/a Eversource Energy**
2 **Allocated Embedded Cost of Service Study**
3 **TABLE 2. GROSS PLANT IN SERVICE**
4 **PRO FORMA TEST YEAR 2018**
5 **(in thousands)**
6

| Line | Minimum System % | Account | Description | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | | | | | | | | | |
| 10 | | | **INTANGIBLE PLANT** | | | | | | | | | | | | | | |
| 11 | | 301 | Organization Intangible Plant | O_LABOR | 45 | 30 | 0 | 1 | 8 | 0 | 0 | 0 | 3 | 2 | 0 | 0 | 0 |
| 12 | | 303 | Miscellaneous Intangible Plant | O_LABOR | 52,915 | 34,866 | 190 | 789 | 9,779 | 24 | 16 | 22 | 4,095 | 2,162 | 96 | 539 | 337 |
| 13 | | | | | | | | | | | | | | | | | |
| 14 | | | **Total Intangible Plant In service (sum of lines 11 to 12)** | | **52,960** | **34,896** | **190** | **790** | **9,787** | **24** | **16** | **22** | **4,098** | **2,164** | **96** | **539** | **337** |
| 15 | | | | | | | | | | | | | | | | | |
| 16 | | | **DISTRIBUTION PLANT** | | | | | | | | | | | | | | |
| 17 | | 360 | Land & Land Rights | 20CP/NCP_P | 9,953 | 4,798 | 56 | 119 | 2,114 | 6 | 6 | 4 | 1,739 | 1,057 | 35 | 11 | 9 |
| 18 | | 361 | Structures & Improvements | 20CP/NCP_P | 26,388 | 12,721 | 149 | 315 | 5,604 | 15 | 15 | 10 | 4,610 | 2,803 | 92 | 30 | 25 |
| 19 | | 362 | Station Equipment | 20CP/NCP_P | 306,248 | 147,637 | 1,726 | 3,650 | 65,043 | 175 | 171 | 112 | 53,507 | 32,526 | 1,064 | 347 | 289 |
| 20 | | | | | | | | | | | | | | | | | |
| 21 | | 364 | **Poles, Towers, & Fixtures** | | | | | | | | | | | | | | |
| 22 | 19.50% | 364 | Primary-Demand | NCP_P | 59,189 | 28,180 | 330 | 1,089 | 12,493 | 49 | 33 | 26 | 10,126 | 6,293 | 327 | 132 | 110 |
| 23 | 63.54% | 364 | Primary Customer | CUST_D | 192,888 | 162,864 | - | - | 28,259 | - | - | - | 511 | 39 | 7 | 729 | 479 |
| 24 | 2.87% | 364 | Secondary-Demand | NCP_S | 8,712 | 6,389 | 75 | 247 | 1,922 | 11 | 7 | 6 | - | - | - | 30 | 25 |
| 25 | 14.10% | 364 | Secondary-Customer | CUST_S | 42,799 | 37,682 | - | - | 4,837 | - | - | - | - | - | - | 169 | 111 |
| 26 | | 364 | **Total (sum of lines 22 to 25)** | | **303,588** | **235,116** | **404** | **1,336** | **47,511** | **61** | **40** | **32** | **10,637** | **6,332** | **333** | **1,060** | **725** |
| 27 | | | | | | | | | | | | | | | | | |
| 28 | | 365 | **OH Conductor & Devices** | | | | | | | | | | | | | | |
| 29 | 58.74% | 365 | OH Primary-Demand | NCP_P | 341,912 | 162,788 | 1,904 | 6,292 | 72,169 | 285 | 190 | 149 | 58,495 | 36,352 | 1,887 | 764 | 636 |
| 30 | 40.41% | 365 | OH Primary-Customer | CUST_D | 235,204 | 198,593 | - | - | 34,459 | - | - | - | 623 | 48 | 8 | 889 | 584 |
| 31 | 0.57% | 365 | OH Secondary-Demand | NCP_S | 3,292 | 2,414 | 28 | 93 | 726 | 4 | 3 | 2 | - | - | - | 11 | 9 |
| 32 | 0.29% | 365 | OH Secondary-Customer | CUST_S | 1,688 | 1,486 | - | - | 191 | - | - | - | - | - | - | 7 | 4 |
| 33 | | 365 | **Total (sum of lines 29 to 32)** | | **582,096** | **365,282** | **1,932** | **6,386** | **107,545** | **290** | **192** | **152** | **59,118** | **36,400** | **1,895** | **1,671** | **1,234** |
| 34 | | | | | | | | | | | | | | | | | |
| 35 | | 366 | **UG Conduit** | | | | | | | | | | | | | | |
| 36 | 22.35% | 366 | Primary-Demand -polyphase | NCP_P | 8,661 | 4,124 | 48 | 159 | 1,828 | 7 | 5 | 4 | 1,482 | 921 | 48 | 19 | 16 |
| 37 | 46.58% | 366 | Primary-Demand - single phase | NCP_P_1ph | 18,052 | 13,252 | 155 | 512 | 3,985 | 15 | 10 | 8 | - | - | - | 62 | 52 |
| 38 | 1.74% | 366 | Primary-Customer - polyphase | CUST_D | 673 | 568 | - | - | 99 | - | - | - | 2 | 0 | 0 | 3 | 2 |
| 39 | 10.03% | 366 | Primary-Customer - single phase | CUST_D_1ph | 3,888 | 3,423 | - | - | 439 | - | - | - | - | - | - | 15 | 10 |
| 40 | 11.28% | 366 | Secondary-Demand - single phase | NCP_S_1ph | 4,371 | 3,209 | 38 | 124 | 965 | 4 | 2 | 2 | - | - | - | 15 | 13 |
| 41 | 8.03% | 366 | Secondary-Customer single phase | CUST_D_1ph | 3,112 | 2,740 | - | - | 352 | - | - | - | - | - | - | 12 | 8 |
| 42 | | 366 | **Total (sum of lines 36 to 41)** | | **38,758** | **27,317** | **241** | **796** | **7,669** | **26** | **17** | **14** | **1,484** | **921** | **48** | **127** | **100** |
| 43 | | | | | | | | | | | | | | | | | |
| 44 | | 367 | **UG Conductor & Devices** | | | | | | | | | | | | | | |
| 45 | 22.35% | 367 | Primary-Demand -polyphase | NCP_P | 29,888 | 14,230 | 166 | 550 | 6,309 | 25 | 17 | 13 | 5,113 | 3,178 | 165 | 67 | 56 |
| 46 | 46.58% | 367 | Primary-Demand -single phase | NCP_P_1ph | 62,293 | 45,730 | 535 | 1,768 | 13,753 | 52 | 35 | 27 | - | - | - | 215 | 179 |
| 47 | 1.74% | 367 | Primary-Customer - polyphase | CUST_D | 2,323 | 1,961 | - | - | 340 | - | - | - | 6 | 0 | 0 | 9 | 6 |
| 48 | 10.03% | 367 | Primary-Customer - single phase | CUST_D_1ph | 13,417 | 11,813 | - | - | 1,516 | - | - | - | - | - | - | 53 | 35 |
| 49 | 11.28% | 367 | Secondary-Demand | NCP_S_1ph | 15,084 | 11,074 | 129 | 428 | 3,330 | 13 | 8 | 7 | - | - | - | 52 | 43 |
| 50 | 8.03% | 367 | Secondary-Customer | CUST_D_1ph | 10,737 | 9,453 | - | - | 1,214 | - | - | - | - | - | - | 42 | 28 |
| 51 | | 367 | **Total (sum of lines 45 to 50)** | | **133,742** | **94,262** | **831** | **2,746** | **26,462** | **90** | **60** | **47** | **5,119** | **3,178** | **165** | **437** | **346** |
| 52 | | | | | | | | | | | | | | | | | |
| 53 | | 368 | **Line Transformers** | | | | | | | | | | | | | | 1.2 |
| 54 | 13.780% | 368 | OH - Demand | NCP_P_ADJ | 35,544 | 18,945 | 222 | 732 | 8,254 | 33 | 22 | 17 | 5,195 | 1,943 | 17 | 89 | 74 |
| 55 | 17.147% | 368 | UG - Demand | NCP_P_ADJ | 44,230 | 23,575 | 276 | 911 | 10,271 | 41 | 27 | 22 | 6,464 | 2,418 | 21 | 111 | 92 |
| 56 | 64.487% | 368 | OH - Customer | Cust_368 | 166,339 | 140,913 | - | - | 24,027 | - | - | - | 337 | 16 | 0 | 631 | 414 |
| 57 | 4.59% | 368 | UG - Customer | Cust_368 | 11,828 | 10,020 | - | - | 1,709 | - | - | - | 24 | 1 | 0 | 45 | 29 |
| 58 | | | | | | | | | | | | | | | | | |
| 59 | | 368 | Capacitors | POWERF | 4,541 | 2,206 | - | - | 978 | - | - | - | 937 | 359 | 19 | 23 | 19 |
| 60 | | | **Total 368 (sum of lines 54 to 59)** | | **262,481** | **195,659** | **497** | **1,644** | **45,238** | **75** | **50** | **39** | **12,958** | **4,737** | **57** | **898** | **629** |
| 61 | | | | | | | | | | | | | | | | | |
| 62 | | 369 | Services - Customer | SERV_369 | 158,352 | 127,548 | - | - | 30,731 | - | - | - | - | - | - | 23 | 51 |
| 63 | | 370 | Meters - Customer | METER_370 | 90,764 | 60,816 | 565 | 5,452 | 21,365 | 139 | 31 | 161 | 2,042 | 166 | 27 | - | - |
| 64 | | 371 | Inst. On Cust. Premises - Cust | CUST_371 | 6,564 | - | - | - | - | - | - | - | - | - | - | 6,564 | - |
| 65 | | 373 | Street Lighting - Customer | ST_DIRECT | 5,131 | - | - | - | - | - | - | - | - | - | - | 5,131 | - |
| 67 | | | | | | | | | | | | | | | | | |
| 68 | | | **Total Distribution Gross Plant** | | **1,924,064** | **1,271,155** | **6,401** | **22,442** | **359,283** | **874** | **581** | **569** | **151,214** | **88,121** | **3,716** | **16,298** | **3,409** |
| 69 | | | | | | | | | | | | | | | | | |
| 70 | | | **GENERAL PLANT** | | | | | | | | | | | | | | |
| 71 | | | | | | | | | | | | | | | | | |
| 72 | | 389 | Land & Land Rights | O_LABOR | 4,834 | 3,185 | 17 | 72 | 893 | 2 | 1 | 2 | 374 | 198 | 9 | 49 | 31 |
| 73 | | 390 | Structures & Improvements | O_LABOR | 84,414 | 55,621 | 303 | 1,259 | 15,600 | 39 | 25 | 34 | 6,532 | 3,449 | 154 | 860 | 537 |
| 74 | | 391 | Office Furniture & Equipment | O_LABOR | 11,442 | 7,539 | 41 | 171 | 2,115 | 5 | 3 | 5 | 885 | 468 | 21 | 117 | 73 |
| 75 | | 392 | Transportation Equipment | O_LABOR | 44,177 | 29,109 | 159 | 659 | 8,164 | 20 | 13 | 18 | 3,419 | 1,805 | 80 | 450 | 281 |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 76 | 393 | Stores Equipment | O_LABOR | 3,258 | 2,147 | 12 | 49 | 602 | 2 | 1 | 1 | 252 | 133 | 6 | 33 | 21 |
| 77 | 394 | Tool, Shop & Garage Equipment | O_LABOR | 14,195 | 9,353 | 51 | 212 | 2,623 | 7 | 4 | 6 | 1,098 | 580 | 26 | 145 | 90 |
| 78 | 395 | Laboratory Equipment | O_LABOR | 2,073 | 1,366 | 7 | 31 | 383 | 1 | 1 | 1 | 160 | 85 | 4 | 21 | 13 |
| 79 | 396 | Power Operated Equipment | O_LABOR | 159 | 105 | 1 | 2 | 29 | 0 | 0 | 0 | 12 | 7 | 0 | 2 | 1 |
| 80 | 397 | Communication Equipment | O_LABOR | 28,189 | 18,574 | 101 | 420 | 5,209 | 13 | 8 | 12 | 2,181 | 1,152 | 51 | 287 | 179 |
| 81 | 398 | Miscellaneous Equipment | O_LABOR | 1,279 | 843 | 5 | 19 | 236 | 1 | 0 | 1 | 99 | 52 | 2 | 13 | 8 |
| 82 | | | | | | | | | | | | | | | | |
| 83 | | **Total General Gross Plant (sum of lines 72 to 81)** | | **194,021** | **127,842** | **697** | **2,894** | **35,855** | **89** | **57** | **79** | **15,014** | **7,928** | **353** | **1,976** | **1,235** |
| 84 | | | | | | | | | | | | | | | | |
| 85 | | **Total Gross Plant (Line 68 + Line 84)** | | **2,171,045** | **1,433,894** | **7,289** | **26,126** | **404,925** | **988** | **654** | **670** | **170,327** | **98,212** | **4,166** | **18,813** | **4,981** |
| 86 | | | | | | | | | | | | | | | | |
| 87 | Total plant balances are from Schedule EHC/TMD-37, Page 2 | | | | | | | | | | | | | | | |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 3-A. ACCUMULATED DEPRECIATION**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Account | DESCRIPTION | ALLOCATOR | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **INTANGIBLE PLANT** | | | | | | | | | | | | | | |
| 303D | Intangible Plant | INTPLANT | 46,159 | 30,415 | 166 | 689 | 8,530 | 21 | 14 | 19 | 3,572 | 1,886 | 84 | 470 | 294 |
| | **DISTRIBUTION PLANT** | | | | | | | | | | | | | | |
| 360 | Land & Land Rights | | | | | | | | | | | | | | |
| 361 | Structures & Improvements | STRUCT_D | 6,382 | 3,077 | 36 | 76 | 1,355 | 4 | 4 | 2 | 1,115 | 678 | 22 | 7 | 6 |
| 362 | Station Equipment | DIS_STATION | 62,750 | 30,251 | 354 | 748 | 13,327 | 36 | 35 | 23 | 10,964 | 6,665 | 218 | 71 | 59 |
| 364 | Poles, Towers & Fixtures | POL_PLANT | 136,745 | 105,903 | 182 | 602 | 21,401 | 27 | 18 | 14 | 4,791 | 2,852 | 150 | 477 | 326 |
| 365 | OH Conductor & Devices | OH_LINE | 113,599 | 71,287 | 377 | 1,246 | 20,988 | 57 | 38 | 30 | 11,537 | 7,104 | 370 | 326 | 241 |
| 366 | UG Conduit | UG_LINE | 5,593 | 3,942 | 35 | 115 | 1,107 | 4 | 2 | 2 | 214 | 133 | 7 | 18 | 14 |
| 367 | UG Conductor & Devices | UG_LINE | 41,988 | 29,593 | 261 | 862 | 8,308 | 28 | 19 | 15 | 1,607 | 998 | 52 | 137 | 109 |
| 368 | Line Transformers | TRANSF_PLANT | 78,707 | 59,030 | 152 | 502 | 13,505 | 23 | 15 | 12 | 3,668 | 1,336 | 12 | 267 | 186 |
| 369 | Services | CUS_369 | 35,251 | 28,394 | - | - | 6,841 | - | - | - | - | - | - | 5 | 11 |
| 370 | Meters | MET_PLANT | 17,297 | 11,590 | 108 | 1,039 | 4,072 | 26 | 6 | 31 | 389 | 32 | 5 | - | - |
| 371 | Inst. On Cust. Premises | CUST_371 | 1,207 | - | - | - | - | - | - | - | - | - | - | 1,207 | - |
| 373 | Street Lighting | ST_DIRECT | 3,821 | - | - | - | - | - | - | - | - | - | - | 3,821 | - |
| | **Total Accu. Depr. Distribution Plant (sum of lines 15 to 26)** | | 503,340 | 343,065 | 1,504 | 5,189 | 90,904 | 204 | 136 | 128 | 34,285 | 19,797 | 836 | 6,337 | 953 |
| | **GENERAL PLANT** | | | | | | | | | | | | | | |
| 389 | Land & Land Rights | | | | | | | | | | | | | | |
| 390D | Structures & Improvements | GPLANT | 15,490 | 10,206.26 | 55.65 | 231.04 | 2,862.48 | 7.14 | 4.55 | 6.33 | 1,198.67 | 632.92 | 28.18 | 157.76 | 98.62 |
| 391D | Office Furniture & Equipemtn | GPLANT | 1,311 | 863.82 | 4.71 | 19.55 | 242.27 | 0.60 | 0.39 | 0.54 | 101.45 | 53.57 | 2.39 | 13.35 | 8.35 |
| 392D | Transportation Equipment | GPLANT | 23,271 | 15,333.49 | 83.60 | 347.11 | 4,300.48 | 10.73 | 6.84 | 9.51 | 1,800.84 | 950.88 | 42.34 | 237.01 | 148.17 |
| 393D | Stores Equipment | GPLANT | 723 | 476.58 | 2.60 | 10.79 | 133.66 | 0.33 | 0.21 | 0.30 | 55.97 | 29.55 | 1.32 | 7.37 | 4.61 |
| 394D | Tool, Shop & Garage Equipment | GPLANT | 3,214 | 2,117.79 | 11.55 | 47.94 | 593.96 | 1.48 | 0.95 | 1.31 | 248.72 | 131.33 | 5.85 | 32.73 | 20.46 |
| 395D | Laboratory Equipment | GPLANT | 329 | 216.68 | 1.18 | 4.91 | 60.77 | 0.15 | 0.10 | 0.13 | 25.45 | 13.44 | 0.60 | 3.35 | 2.09 |
| 396D | Power Operated Equipment | GPLANT | 104 | 68.26 | 0.37 | 1.55 | 19.14 | 0.05 | 0.03 | 0.04 | 8.02 | 4.23 | 0.19 | 1.06 | 0.66 |
| 397D | Communication Equipment | GPLANT | 7,992 | 5,265.87 | 28.71 | 119.21 | 1,476.88 | 3.68 | 2.35 | 3.27 | 618.45 | 326.55 | 14.54 | 81.39 | 50.88 |
| 398D | Miscellaneous Equipment | GPLANT | 494 | 325.57 | 1.78 | 7.37 | 91.31 | 0.23 | 0.15 | 0.20 | 38.24 | 20.19 | 0.90 | 5.03 | 3.15 |
| | | GPLANT | | | | | | | | | | | | | |
| | **Total Accu. Deprec. General Plant (sum of lines 31 to 40)** | | 52,927 | 34,874 | 190 | 789 | 9,781 | 24 | 16 | 22 | 4,096 | 2,163 | 96 | 539 | 337 |
| | **Total Accu. Depreciation (Line 12 + 28 + 42)** | | **602,426** | **408,354** | **1,860** | **6,667** | **109,215** | **250** | **166** | **169** | **41,953** | **23,845** | **1,016** | **7,346** | **1,584** |

Total plant balances are from Schedule EHC/TMD-38, Page 2

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 3-B. NET PLANT IN SERVICE**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Ln | Account | Description | Reference | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | **NET PLANT** | | | | | | | | | | | | | | |
| 12 | 301-303 | **Total Intangible Net Plant** | Table 2, Ln 14 - Table 3, Ln. 12 | 6,801 | 4,481 | 24 | 101 | 1,257 | 3 | 2 | 3 | 526 | 278 | 12 | 69 | 43 |
| 14 | | **DISTRIBUTION PLANT** | | | | | | | | | | | | | | |
| 15 | 360 | Land & Land Rights | Table 2, Ln 17 - Table 3, Ln 15 | 9,953 | 4,798 | 56 | 119 | 2,114 | 6 | 6 | 4 | 1,739 | 1,057 | 35 | 11 | 9 |
| 16 | 361 | Structures & Improvements | Table 2, Ln 18 - Table 3, Ln 16 | 20,006 | 9,644 | 113 | 238 | 4,249 | 11 | 11 | 7 | 3,495 | 2,125 | 69 | 23 | 19 |
| 17 | 362 | Station Equipment | Table 2, Ln 19 - Table 3, Ln 17 | 243,498 | 117,386 | 1,373 | 2,902 | 51,716 | 139 | 136 | 89 | 42,544 | 25,862 | 846 | 276 | 230 |
| 18 | 364 | Poles, Towers & Fixtures | Table 2, Ln 26 - Table 3, Ln 18 | 166,843 | 129,213 | 222 | 734 | 26,111 | 33 | 22 | 17 | 5,846 | 3,480 | 183 | 582 | 398 |
| 19 | 365 | OH Conductor & Devices | Table 2, Ln 33 - Table 3, Ln 19 | 468,497 | 293,995 | 1,555 | 5,139 | 86,557 | 233 | 155 | 122 | 47,581 | 29,296 | 1,526 | 1,345 | 993 |
| 20 | 366 | UG Conduit | Table 2, Ln 42 - Table 3, Ln 20 | 33,165 | 23,375 | 206 | 681 | 6,562 | 22 | 15 | 12 | 1,269 | 788 | 41 | 108 | 86 |
| 21 | 367 | UG Conductor & Devices | Table 2, Ln 51 - Table 3, Ln 21 | 91,754 | 64,669 | 570 | 1,884 | 18,154 | 62 | 41 | 32 | 3,512 | 2,180 | 113 | 300 | 237 |
| 22 | 368 | Line Transformers | Table 2, Ln 60 - Table 3, Ln 22 | 183,774 | 136,630 | 346 | 1,142 | 31,733 | 52 | 34 | 27 | 9,290 | 3,401 | 46 | 631 | 443 |
| 23 | 369 | Services | Table 2, Ln 62 - Table 3, Ln 23 | 123,101 | 99,154 | - | - | 23,890 | - | - | - | - | - | - | 18 | 40 |
| 24 | 370 | Meters | Table 2, Ln 63 - Table 3, Ln 24 | 73,467 | 49,226 | 458 | 4,413 | 17,294 | 112 | 25 | 130 | 1,653 | 134 | 22 | - | - |
| 25 | 371 | Inst. On Cust. Premises | Table 2, Ln 64 - Table 3, Ln 25 | 5,357 | - | - | - | - | - | - | - | - | - | - | 5,357 | - |
| 26 | 373 | Street Lighting | Table 2, Ln 65 - Table 3, Ln 26 | 1,310 | - | - | - | - | - | - | - | - | - | - | 1,310 | - |
| 28 | | **Total Distribution Net Plant** | Sum of Lines 15 to 26 | 1,420,725 | 928,090 | 4,898 | 17,253 | 268,379 | 670 | 445 | 441 | 116,929 | 68,324 | 2,880 | 9,960 | 2,456 |
| 30 | | **GENERAL PLANT** | | | | | | | | | | | | | | |
| 31 | 389 | Land & Land Rights | Table 2, Ln 72 - Table 3, Ln 31 | 4,834 | 3,185 | 17 | 72 | 893 | 2 | 1 | 2 | 374 | 198 | 9 | 49 | 31 |
| 33 | 390D | Structures & Improvements | Table 2, Ln 73 - Table 3, Ln 32 | 68,925 | 45,415 | 248 | 1,028 | 12,737 | 32 | 20 | 28 | 5,334 | 2,816 | 125 | 702 | 439 |
| 34 | 391D | Office Furniture & Equipment | Table 2, Ln 74 - Table 3, Ln 33 | 10,131 | 6,676 | 36 | 151 | 1,872 | 5 | 3 | 4 | 784 | 414 | 18 | 103 | 65 |
| 35 | 392D | Transportation Equipment | Table 2, Ln 75 - Table 3, Ln 34 | 20,906 | 13,775 | 75 | 312 | 3,863 | 10 | 6 | 9 | 1,618 | 854 | 38 | 213 | 133 |
| 36 | 393D | Stores Equipment | Table 2, Ln 76 - Table 3, Ln 35 | 2,535 | 1,670 | 9 | 38 | 468 | 1 | 1 | 1 | 196 | 104 | 5 | 26 | 16 |
| 37 | 394D | Tool, Shop & Garage Equipment | Table 2, Ln 77 - Table 3, Ln 36 | 10,981 | 7,235 | 39 | 164 | 2,029 | 5 | 3 | 4 | 850 | 449 | 20 | 112 | 70 |
| 38 | 395D | Laboratory Equipment | Table 2, Ln 78 - Table 3, Ln 37 | 1,744 | 1,149 | 6 | 26 | 322 | 1 | 1 | 1 | 135 | 71 | 3 | 18 | 11 |
| 39 | 396D | Power Operated Equipment | Table 2, Ln 79 - Table 3, Ln 38 | 56 | 37 | 0 | 1 | 10 | 0 | 0 | 0 | 4 | 2 | 0 | 1 | 0 |
| 40 | 397D | Communication Equipment | Table 2, Ln 80 - Table 3, Ln 39 | 20,197 | 13,308 | 73 | 301 | 3,732 | 9 | 6 | 8 | 1,563 | 825 | 37 | 206 | 129 |
| 41 | 398D | Miscellaneous Equipment | Table 2, Ln 81 - Table 3, Ln 40 | 785 | 517 | 3 | 12 | 145 | 0 | 0 | 0 | 61 | 32 | 1 | 8 | 5 |
| 43 | | **Total General Net Plant** | Sum of Lines 33 to 41 | 141,094 | 92,968 | 507 | 2,105 | 26,074 | 65 | 41 | 58 | 10,919 | 5,765 | 257 | 1,437 | 898 |
| 45 | | **Total Net Plant** | Line 12 + Line 28 + Line 43 | **1,568,619** | **1,025,539** | **5,429** | **19,459** | **295,710** | **738** | **488** | **501** | **128,374** | **74,367** | **3,150** | **11,467** | **3,397** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 4. RATE BASE**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | **RATE BASE** | | | | | | | | | | | | | | | |
| 12 | | Utility Plant in Service | Table 2, Line 85 | | 2,171,045 | 1,433,894 | 7,289 | 26,126 | 404,925 | 988 | 654 | 670 | 170,327 | 98,212 | 4,166 | 18,813 | 4,981 |
| 14 | | Reserve For Depreciation | Table 3, Line 44 | | 602,426 | 408,354 | 1,860 | 6,667 | 109,215 | 250 | 166 | 169 | 41,953 | 23,845 | 1,016 | 7,346 | 1,584 |
| 16 | | **Net Plant** | Line 12 - Line 14 | | **1,568,619** | **1,025,539** | **5,429** | **19,459** | **295,710** | **738** | **488** | **501** | **128,374** | **74,367** | **3,150** | **11,467** | **3,397** |
| 18 | | **DEDUCTIONS FROM PLANT** | | | | | | | | | | | | | | | |
| 19 | | Reserve for Deferred Income Taxes | Sch. EHC/TMD-36 | NETPLANT | 370,640 | 242,319 | 1,283 | 4,598 | 69,872 | 174 | 115 | 118 | 30,333 | 17,572 | 744 | 2,709 | 803 |
| 21 | | Regulatory Liabilities | Sch. EHC/TMD-36 | NETPLANT | 4,037 | 2,639 | 14 | 50 | 761 | 2 | 1 | 1 | 330 | 191 | 8 | 30 | 9 |
| 22 | 235 | Customer Deposits/Advances | Sch. EHC/TMD-36 | CUST_235 | 8,401 | 3,858 | - | - | 4,257 | - | - | - | 183 | 96 | 8 | 0 | 0 |
| 24 | | **Total Deductions from Plant** | Sum of Lines 19 to 22 | | **383,078** | **248,816** | **1,297** | **4,648** | **74,889** | **176** | **117** | **120** | **30,846** | **17,859** | **760** | **2,739** | **812** |
| 26 | | **ADDITIONS TO PLANT** | | | | | | | | | | | | | | | |
| 27 | | Distribution Cash Working Capital | Sch. EHC/TMD-36 | OM_PT | 13,761 | 8,657 | 39 | 172 | 2,746 | 7 | 3 | 5 | 1,237 | 672 | 36 | 118 | 69 |
| 28 | | Materials and Supplies | Sch. EHC/TMD-36 | NETPLANT | 12,213 | 7,985 | 42 | 152 | 2,302 | 6 | 4 | 4 | 1,000 | 579 | 25 | 89 | 26 |
| 29 | | Prepayments | Sch. EHC/TMD-36 | NETPLANT | 729 | 476 | 3 | 9 | 137 | 0 | 0 | 0 | 60 | 35 | 1 | 5 | 2 |
| 30 | | Regulatory Assets | Sch. EHC/TMD-36 | NETPLANT | 3,423 | 2,238 | 12 | 42 | 645 | 2 | 1 | 1 | 280 | 162 | 7 | 25 | 7 |
| 32 | | **Total Additions** | Sum of Lines 27 to 30 | | **30,126** | **19,356** | **96** | **375** | **5,832** | **14** | **8** | **10** | **2,577** | **1,447** | **69** | **238** | **105** |
| 34 | | **TOTAL RATE BASE** | Line 16 - 24 + 32 | | **1,215,668** | **796,079** | **4,228** | **15,186** | **226,652** | **576** | **380** | **392** | **100,105** | **57,956** | **2,458** | **8,965** | **2,690** |
| 36 | | **COST OF CAPITAL** | Sch. EHC/TMD-3 | | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% | 7.62% |
| 38 | | **RETURN ON RATE BASE** | Line 34 x Line 36 | | **92,590** | **60,633** | **322** | **1,157** | **17,263** | **44** | **29** | **30** | **7,624** | **4,414** | **187** | **683** | **205** |

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**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 5. OPERATING REVENUES**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **OPERATING REVENUES** | | | | | | | | | | | | | | | |
| 440-446 | Distribution Sales Revenue | Att. EHC/TMD-4, p. 1 | DREV | 349,862 | 197,030 | 447 | 4,188 | 83,801 | 201 | 29 | 137 | 36,149 | 18,814 | 1,489 | 4,501 | 3,077 |
| | **OTHER OPERATING REVENUES** | | | | | | | | | | | | | | | |
| 447 | Resales Revenue | Att. EHC/TMD-4, p. 1 | DPLANT_P | 4,931 | 3,001 | 18 | 49 | 930 | 2 | 2 | 1 | 554 | 338 | 15 | 12 | 9 |
| 450 | Late Payment Charge | Att. EHC/TMD-4, p. 1 | LATE | 1,959 | 1,589 | - | - | 262 | - | - | - | 69 | 36 | - | 1 | 1 |
| 451 | Collection Charges | Att. EHC/TMD-4, p. 2 | 451_CC | 1,095 | 939 | - | - | 150 | - | - | - | 6 | - | - | - | - |
| 451 R14 | Reconnect-Reactivation Fees | Att. EHC/TMD-4, p. 2 | 451_RR | 2,433 | 2,238 | - | - | 189 | - | - | - | 6 | - | - | - | - |
| 451 R15 | Returned Check Fees | Att. EHC/TMD-4, p. 2 | 451_RC | 193 | 176 | - | - | 16 | - | - | - | 1 | - | - | - | - |
| 451 Misc | Other Misc. Service Revenues | Att. EHC/TMD-4, p. 2 | 451_Misc | (5) | (4) | - | - | (1) | - | - | - | (0) | - | - | - | - |
| 454 | Pole and Cable TV Rental | Att. EHC/TMD-4, p. 3 | POL_PLANT | 2,135 | 1,654 | 3 | 9 | 334 | 0 | 0 | 0 | 75 | 45 | 2 | 7 | 5 |
| 454 | Apparatus Rental Revenue | Att. EHC/TMD-4, p. 3 | TRANSF_454 | 3,365 | - | - | - | 8 | - | - | - | 2,648 | 700 | 9 | - | - |
| 454 | Other Rent from Electric Property | Att. EHC/TMD-4, p. 3 | OHPLANT | 269 | 182 | 1 | 2 | 47 | 0 | 0 | 0 | 21 | 13 | 1 | 1 | 1 |
| 456 | Other Electric Revenue | Att. EHC/TMD-4, p. 1 | DPLANT | 52 | 34 | 0 | 1 | 10 | 0 | 0 | 0 | 4 | 2 | 0 | 0 | 0 |
| | Total Other Revenues | Sum of Lines 15 to 24 | | **16,428** | **9,810** | **22** | **62** | **1,945** | **3** | **2** | **2** | **3,384** | **1,134** | **27** | **22** | **16** |
| | **TOTAL OPERATING REVENUE** | Line 12 + Line 26 | | **366,290** | **206,841** | **468** | **4,250** | **85,746** | **204** | **31** | **138** | **39,533** | **19,948** | **1,516** | **4,523** | **3,092** |

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Attachment ACOSS-2 (Perm)
May 28, 2019


**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 6. OPERATION AND MAINTENANCE EXPENSES**
**PRO FORMA TEST YEAR 2018**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | **OPERATING & MAINTENANCE EXPENSE** | | | | | | | | | | | | | | | |
| 12 | | **OPERATION** | | | | | | | | | | | | | | | |
| 13 | 555-557, 569 | Allocated Production and Transmission expenses | Att. EHC/TMD-5, p. 3 | DIS_STATION | 109 | 52 | 1 | 1 | 23 | 0 | 0 | 0 | 19 | 12 | 0 | 0 | 0 |
| 14 | 580 | Sup. & Eng. | Att. EHC/TMD-5, p. 3 | LABOR_D_O | 9,333 | 5,370 | 43 | 205 | 1,843 | 7 | 4 | 6 | 883 | 508 | 19 | 276 | 168 |
| 15 | 581 | Load Dispatching | Att. EHC/TMD-5, p. 3 | DIS_STATION | 978 | 472 | 6 | 12 | 208 | 1 | 1 | 0 | 171 | 104 | 3 | 1 | 1 |
| 16 | 582 | Station Expense | Att. EHC/TMD-5, p. 3 | DIS_STATION | 2,589 | 1,248 | 15 | 31 | 550 | 1 | 1 | 1 | 452 | 275 | 9 | 3 | 2 |
| 17 | 583 | Overhead Line Exp. | Att. EHC/TMD-5, p. 3 | OH_LINE | 2,947 | 1,849 | 10 | 32 | 544 | 1 | 1 | 1 | 299 | 184 | 10 | 8 | 6 |
| 18 | 584 | Underground Line Expenses | Att. EHC/TMD-5, p. 3 | UG_LINE | 1,811 | 1,276 | 11 | 37 | 358 | 1 | 1 | 1 | 69 | 43 | 2 | 6 | 5 |
| 19 | 585 | Street Lighting Exp. | Att. EHC/TMD-5, p. 3 | DIRECT ST | 519 | - | - | - | - | - | - | - | - | - | - | 317 | 202 |
| 20 | 586 | Meter Expense | Att. EHC/TMD-5, p. 3 | MET_PLANT | 2,432 | 1,630 | 15 | 146 | 573 | 4 | 1 | 4 | 55 | 4 | 1 | - | - |
| 21 | 587 | Customer Installation | Att. EHC/TMD-5, p. 3 | D_PLANT_587 | 7 | 5 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | 588 | Misc. Expense | Att. EHC/TMD-5, p. 3 | DPLANT | 2,691 | 1,778 | 9 | 31 | 502 | 1 | 1 | 1 | 211 | 123 | 5 | 23 | 5 |
| 23 | 589 | Rent, Other Expense (Pole rental) | Att. EHC/TMD-5, p. 3 | POL_PLANT | 1,131 | 876 | 2 | 5 | 177 | 0 | 0 | 0 | 40 | 24 | 1 | 4 | 3 |
| 25 | | Distribution Operation Expenses plus Allocated Transm. Expense (sum of lines 13 to 23) | | | 24,545 | 14,555 | 111 | 501 | 4,779 | 17 | 9 | 14 | 2,200 | 1,277 | 51 | 639 | 392 |
| 28 | | **MAINTENANCE** | | | | | | | | | | | | | | | |
| 29 | 590 | Sup. & Eng. | Att. EHC/TMD-5, p. 3 | LABOR_D_M | 175 | 109 | 1 | 2 | 33 | 0 | 0 | 0 | 18 | 11 | 1 | 1 | 1 |
| 30 | 591 | Structure | Att. EHC/TMD-5, p. 3 | DPLANT | 256 | 169 | 1 | 3 | 48 | 0 | 0 | 0 | 20 | 12 | 0 | 2 | 0 |
| 31 | 592 | Station Equipment | Att. EHC/TMD-5, p. 3 | DIS_STATION | 1,746 | 842 | 10 | 21 | 371 | 1 | 1 | 1 | 305 | 185 | 6 | 2 | 2 |
| 32 | 593 | OH Lines, Poles, Towers & Fixtures | Att. EHC/TMD-5, p. 3 | OH_LINE | 52,244 | 32,784 | 173 | 573 | 9,652 | 26 | 17 | 14 | 5,306 | 3,267 | 170 | 150 | 111 |
| 33 | 594 | Underground Line Expenses | Att. EHC/TMD-5, p. 3 | UG_LINE | 915 | 645 | 6 | 19 | 181 | 1 | 0 | 0 | 35 | 22 | 1 | 3 | 2 |
| 34 | 595 | Line Transformers | Att. EHC/TMD-5, p. 3 | TRANSF_PLANT | 877 | 658 | 2 | 6 | 150 | 0 | 0 | 0 | 41 | 15 | 0 | 3 | 2 |
| 35 | 596 | Street Lighting | Att. EHC/TMD-5, p. 3 | DIRECT ST | 52 | - | - | - | - | - | - | - | - | - | - | 32 | 20 |
| 36 | 597 | Meters | Att. EHC/TMD-5, p. 3 | MET_PLANT | 351 | 235 | 2 | 21 | 83 | 1 | 0 | 1 | 8 | 1 | 0 | - | - |
| 37 | 598 | Miscellaneous | Att. EHC/TMD-5, p. 3 | DPLANT | 15 | 10 | 0 | 0 | 3 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 |
| 39 | | Total Maintenance Expense | Sum of lines 29 to 37 | | 56,632 | 35,452 | 194 | 645 | 10,521 | 29 | 19 | 15 | 5,734 | 3,513 | 179 | 193 | 138 |
| 41 | | **TOTAL DISTRIBUTION O&M EXPENSES** | Line 25 + Line 39 | | **81,177** | **50,007** | **305** | **1,146** | **15,300** | **45** | **28** | **29** | **7,933** | **4,790** | **230** | **832** | **531** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 7. CUSTOMER ACCOUNT AND CUSTOMER SERVICE & INFORMATION EXPENSES**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | CUSTOMER ACCOUNTS EXPENSES | | | | | | | | | | | | | | | |
| 12 | | CUSTOMER ACCOUNTS | | | | | | | | | | | | | | | |
| 13 | 901 | Supervision Expense | Att. EHC/TMD-5, p. 3 | CUST_ALL | 1 | 1 | - | - | 0 | - | - | - | 0 | 0 | 0 | 0 | 0 |
| 14 | 902 | Meter Reading Expense | Att. EHC/TMD-5, p. 3 | MTR_WF | 2,236 | 1,624 | 35 | 159 | 310 | 2 | 2 | 5 | 93 | 7 | 1 | - | - |
| 15 | 903 | Records & Collection Expense | Att. EHC/TMD-5, p. 3 | COLL903 | 16,615 | 13,100 | - | - | 2,959 | - | - | - | 513 | 42 | - | - | - |
| 16 | 904 | Uncollectible Account Exp. | Att. EHC/TMD-5, p. 3 | UNCOL904 | 3,490 | 3,268 | - | - | 201 | - | - | - | 3 | 2 | - | 10 | 7 |
| 17 | 905 | Miscellaneous Expense | Att. EHC/TMD-5, p. 3 | MIS_CUST XP | 137 | 110 | 0 | 1 | 21 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 |
| 19 | | Total Customer Accounts Exp. | Sum of Lines 13 to 17 | | 22,479 | 18,102 | 35 | 160 | 3,491 | 2 | 2 | 5 | 613 | 52 | 1 | 10 | 7 |
| 22 | | CUSTOMER SERVICE & INFORMATION | | | | | | | | | | | | | | | |
| 23 | 908 | Customer Assistance Expense | Att. EHC/TMD-5, p. 3 | CUS_908 | 269 | - | - | - | - | - | - | - | 249 | 21 | - | - | - |
| 24 | 910 | Miscellaneous CS & \| Exp. | Att. EHC/TMD-5, p. 3 | CUS_908 | 10 | - | - | - | - | - | - | - | 9 | 1 | - | - | - |
| 26 | | Total Customer Service Exp. | Line 23 + Line 24 | | 279 | - | - | - | - | - | - | - | 258 | 21 | - | - | - |
| 29 | | SUPERVISION | | | | | | | | | | | | | | | |
| 30 | 911 | Supervision Expense | Att. EHC/TMD-5, p. 3 | CUST EXP_ALL | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 31 | 916 | Supervision & Misc. Expense | | CUST EXP_ALL | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | | Total Customer Edu/Adv. Exp. | Line 30 + Line 31 | | 2 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 35 | | **Total Customer Expense** | Line 19 + Line 26 + Line 33 | | **22,760** | **18,104** | **35** | **160** | **3,492** | **2** | **2** | **5** | **871** | **73** | **1** | **10** | **7** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 8. ADMINISTRATION AND GENERAL EXPENSES**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ADMIN & GENERAL EXPENSES | | | | | | | | | | | | | | | |
| 920 | Salaries | Att. EHC/TMD-5, p. 3 | LABOR_D | 21,556 | 14,382 | 77 | 325 | 3,968 | 10 | 6 | 9 | 1,583 | 805 | 35 | 220 | 137 |
| 921 | Office Supplies Exp. | Att. EHC/TMD-5, p. 3 | DISTOMEXP | 4,113 | 2,585 | 16 | 59 | 791 | 2 | 1 | 2 | 410 | 248 | - | - | - |
| 922 | A & G Exp. Transferred Credits | Att. EHC/TMD-5, p. 3 | DISTOMEXP | (1,858) | (1,167) | (7) | (27) | (357) | (1) | (1) | (1) | (185) | (112) | - | - | - |
| 923 | Outside Service Exp | Att. EHC/TMD-5, p. 3 | LABOR_D | 9,808 | 6,544 | 35 | 148 | 1,805 | 4 | 3 | 4 | 720 | 366 | 16 | 100 | 62 |
| 924 | Property Insurance, Distribution Line | Att. EHC/TMD-5, p. 3 | NPLANT_OH | 164 | 103 | 1 | 2 | 31 | 0 | 0 | 0 | 17 | 10 | 0 | 0 | 0 |
| 925 | Injuries & Damages | Att. EHC/TMD-5, p. 3 | LABOR_D | 2,415 | 1,611 | 9 | 36 | 445 | 1 | 1 | 1 | 177 | 90 | 4 | 25 | 15 |
| 926 | Employee Pension & Benefits | Att. EHC/TMD-5, p. 3 | LABOR_D | 15,665 | 10,452 | 56 | 236 | 2,884 | 7 | 4 | 7 | 1,150 | 585 | 25 | 160 | 99 |
| 928 | Commission Expense, State Regulatory | Att. EHC/TMD-5, p. 3 | DPLANT | 5,052 | 3,338 | 17 | 59 | 943 | 2 | 2 | 1 | 397 | 231 | 10 | 43 | 9 |
| 930 | Miscellaneous General Exp. | Att. EHC/TMD-5, p. 3 | DISTOMEXP | 4,613 | 2,899 | 18 | 66 | 887 | 3 | 2 | 2 | 460 | 278 | - | - | - |
| 931 | Rent | Att. EHC/TMD-5, p. 3 | DPLANT | 2,073 | 1,370 | 7 | 24 | 387 | 1 | 1 | 1 | 163 | 95 | 4 | 18 | 4 |
| 935 | Maintenance of General Plant | Att. EHC/TMD-5, p. 3 | GENPLANT | 188 | 124 | 1 | 3 | 35 | 0 | 0 | 0 | 15 | 8 | 0 | 2 | 1 |
| EXP_O&M_A&G | Total Admin. & Gen. Expense | Sum of Lines 13 to 23 | | **63,791** | **42,239** | **227** | **932** | **11,819** | **29** | **19** | **25** | **4,907** | **2,604** | **95** | **566** | **328** |
| **EXP_O&M** | **Total O&M Expense** | Table 6, ln. 41 + Table 7, ln. 35 + Line 26 | | **167,728** | **110,350** | **567** | **2,238** | **30,611** | **76** | **49** | **59** | **13,711** | **7,467** | **326** | **1,408** | **865** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 9. DEPRECIATION EXPENSE**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | DEPRECIATION EXPENSE | | | | | | | | | | | | | | | |
| 303DEP | Intangible Plant in Service | Att. EHC/TMD-28, p. 2 | INTPLANT | 2,463 | 1,623 | 9 | 37 | 455 | 1 | 1 | 1 | 191 | 101 | 4 | 25 | 16 |
| | DISTRIBUTION PLANT | | | | | | | | | | | | | | | |
| 360DEP | Land & Land Rights | Att. EHC/TMD-28, p. 2 | LANDPLANT | 197 | 95 | 1 | 2 | 42 | 0 | 0 | 0 | 34 | 21 | 1 | 0 | 0 |
| 361DEP | Structures & Improvements | Att. EHC/TMD-28, p. 2 | STRPLANT | 435 | 210 | 2 | 5 | 92 | 0 | 0 | 0 | 76 | 46 | 2 | 0 | 0 |
| 362DEP | Station Equipment | Att. EHC/TMD-28, p. 2 | DIS_STATION | 6,998 | 3,374 | 39 | 83 | 1,486 | 4 | 4 | 3 | 1,223 | 743 | 24 | 8 | 7 |
| 362.10 | Station Equipment -EMS | Att. EHC/TMD-28, p. 2 | DIS_STATION | 130 | 63 | 1 | 2 | 28 | 0 | 0 | 0 | 23 | 14 | 0 | 0 | 0 |
| 364DEP | Poles, Towers & Fixtures | Att. EHC/TMD-28, p. 2 | POL_PLANT | 9,912 | 7,676 | 13 | 44 | 1,551 | 2 | 1 | 1 | 347 | 207 | 11 | 35 | 24 |
| 365DEP | OH Conductor & Devices | Att. EHC/TMD-28, p. 2 | OH_LINE | 15,418 | 9,675 | 51 | 169 | 2,848 | 8 | 5 | 4 | 1,566 | 964 | 50 | 44 | 33 |
| 366DEP | UG Conduit | Att. EHC/TMD-28, p. 2 | UG_LINE | 1,033 | 728 | 6 | 21 | 204 | 1 | 0 | 0 | 40 | 25 | 1 | 3 | 3 |
| 367DEP | UG Conductor & Devices | Att. EHC/TMD-28, p. 2 | UG_LINE | 3,479 | 2,452 | 22 | 71 | 688 | 2 | 2 | 1 | 133 | 83 | 4 | 11 | 9 |
| 368DEP | Line Transformers | Att. EHC/TMD-28, p. 2 | TRANSF_PLANT | 6,424 | 4,818 | 12 | 41 | 1,102 | 2 | 1 | 1 | 299 | 109 | 1 | 22 | 15 |
| 369DEP | Services - OH | Att. EHC/TMD-28, p. 2 | CUS_369 | 5,367 | 4,323 | - | - | 1,042 | - | - | - | - | - | - | 1 | 2 |
| 369DEP | Services - UG | Att. EHC/TMD-28, p. 2 | CUS_369 | 3,620 | 2,916 | - | - | 703 | - | - | - | - | - | - | 1 | 1 |
| 370DEP | Meters | Att. EHC/TMD-28, p. 2 | MET_PLANT | 4,888 | 3,275 | 30 | 294 | 1,151 | 7 | 2 | 9 | 110 | 9 | 1 | - | - |
| 371DEP | Inst. On Cust. Premises | Att. EHC/TMD-28, p. 2 | CUST_371 | 838 | - | - | - | - | - | - | - | - | - | - | 838 | - |
| 373DEP | Street Lighting | Att. EHC/TMD-28, p. 2 | ST_DIRECT | 93 | - | - | - | - | - | - | - | - | - | - | 93 | - |
| | **Total Dist. Plant Dep. Exp.** | Sum of lines 16 to 29 | | **58,832** | **39,605** | **179** | **732** | **10,938** | **26** | **16** | **19** | **3,851** | **2,220** | **96** | **1,056** | **93** |
| | GENERAL PLANT | | | | | | | | | | | | | | | |
| 389 | Land and Land rights | Att. EHC/TMD-28, p. 2 | GPLANT | 1 | 0.65 | 0.00 | 0.01 | 0.18 | 0.00 | 0.00 | 0.00 | 0.08 | 0.04 | 0.00 | 0.01 | 0.01 |
| 390DEP | Structures & Improvements | Att. EHC/TMD-28, p. 2 | GPLANT | 1,993 | 1,312.98 | 7.16 | 29.72 | 368.24 | 0.92 | 0.59 | 0.81 | 154.20 | 81.42 | 3.63 | 20.29 | 12.69 |
| 391DEP | Office Furniture & Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 1,596 | 1,051.52 | 5.73 | 23.80 | 294.91 | 0.74 | 0.47 | 0.65 | 123.50 | 65.21 | 2.90 | 16.25 | 10.16 |
| 393DEP | Stores Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 240 | 158.21 | 0.86 | 3.58 | 44.37 | 0.11 | 0.07 | 0.10 | 18.58 | 9.81 | 0.44 | 2.45 | 1.53 |
| 394DEP | Tool, Shop & Garage Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 732 | 482.61 | 2.63 | 10.93 | 135.36 | 0.34 | 0.22 | 0.30 | 56.68 | 29.93 | 1.33 | 7.46 | 4.66 |
| 395DEP | Laboratory Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 298 | 196.12 | 1.07 | 4.44 | 55.00 | 0.14 | 0.09 | 0.12 | 23.03 | 12.16 | 0.54 | 3.03 | 1.90 |
| 396DEP | Power Operated Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 6 | 3.88 | 0.02 | 0.09 | 1.09 | 0.00 | 0.00 | 0.00 | 0.46 | 0.24 | 0.01 | 0.06 | 0.04 |
| 397DEP | Communication Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 2,923 | 1,926.31 | 10.50 | 43.61 | 540.26 | 1.35 | 0.86 | 1.19 | 226.24 | 119.46 | 5.32 | 29.77 | 18.61 |
| 398DEP | Miscellaneous Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 96 | 63.20 | 0.34 | 1.43 | 17.73 | 0.04 | 0.03 | 0.04 | 7.42 | 3.92 | 0.17 | 0.98 | 0.61 |
| | **TotaL Gen. Plant Dep. Exp.** | Sum of lines 34 to 42 | | **7,885** | **5,195** | **28** | **118** | **1,457** | **4** | **2** | **3** | **610** | **322** | **14** | **80** | **50** |
| EXP_DEP | **Total Depreciation Expense** | Line 12 + Line 31 + Line 44 | | **69,180** | **46,423** | **216** | **887** | **12,850** | **31** | **19** | **23** | **4,652** | **2,643** | **115** | **1,161** | **159** |
| | AMORTIZATION | | | | | | | | | | | | | | | |
| 407 | Amortization of Regulatory Asset | | RBASE | 19,015 | 12,559 | 64 | 229 | 3,547 | 9 | 6 | 6 | 1,492 | 860 | 36 | 165 | 44 |
| | EESCO Depreciation / Amortization | | RBASE | 6,590 | 4,353 | 22 | 79 | 1,229 | 3 | 2 | 2 | 517 | 298 | 13 | 57 | 15 |
| | **Total Amortization Expense** | Line 51 + Line 52 | | **$ 25,606** | **$ 16,912** | **$ 86** | **$ 308** | **$ 4,776** | **$ 12** | **$ 8** | **$ 8** | **$ 2,009** | **$ 1,158** | **$ 49** | **$ 222** | **$ 59** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 10. PAYROLL TAXES AND OTHER NON-INCOME TAXES**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | | | | | | | | | |
| 10 | | **PAYROLL RELATED TAXES** | | | | | | | | | | | | | | | |
| 11 | 408020 | FICA Tax | Att. EHC/TMD-5, p. 4 | O_LABOR | 6,365 | 4,194 | 23 | 95 | 1,176 | 3 | 2 | 3 | 493 | 260 | 12 | 65 | 41 |
| 12 | 408050 | Medicare Tax | Att. EHC/TMD-5, p. 4 | O_LABOR | 1,718 | 1,132 | 6 | 26 | 317 | 1 | 1 | 1 | 133 | 70 | 3 | 17 | 11 |
| 13 | 408010 | Federal Unemployment Tax | Att. EHC/TMD-5, p. 4 | O_LABOR | 38 | 25 | 0 | 1 | 7 | 0 | 0 | 0 | 3 | 2 | 0 | 0 | 0 |
| 14 | | | | | | | | | | | | | | | | | |
| 15 | 408011 | Massachusetts | Att. EHC/TMD-5, p. 4 | O_LABOR | 48 | 32 | 0 | 1 | 9 | 0 | 0 | 0 | 4 | 2 | 0 | 0 | 0 |
| 16 | 408001 | Connecticut | Att. EHC/TMD-5, p. 4 | O_LABOR | 68 | 45 | 0 | 1 | 13 | 0 | 0 | 0 | 5 | 3 | 0 | 1 | 0 |
| 17 | 4081H0 | New Hampshire | Att. EHC/TMD-5, p. 4 | O_LABOR | 14 | 9 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 |
| 18 | 408360 | District of Columbia | Att. EHC/TMD-5, p. 4 | O_LABOR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | 408180 | Universal Health | Att. EHC/TMD-5, p. 4 | O_LABOR | 9 | 6 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| 20 | | Payroll Taxes Transferred-Credit | Att. EHC/TMD-32, p. 2 | O_LABOR | (3,846) | (2,534) | (14) | (57) | (711) | (2) | (1) | (2) | (298) | (157) | (7) | (39) | (24) |
| 21 | | **Net Payroll Taxes** | Sum of lines 11 to 20 | | **4,413** | **2,908** | **16** | **66** | **816** | **2** | **1** | **2** | **342** | **180** | **8** | **45** | **28** |
| 22 | | | | | | | | | | | | | | | | | |
| 23 | 408.19 | **Property Tax** | Att. EHC/TMD-5, p. 4 | NETPLANT | **47,399** | **30,989** | **164** | **588** | **8,936** | **22** | **15** | **15** | **3,879** | **2,247** | **95** | **346** | **103** |
| 24 | | | | | | | | | | | | | | | | | |
| 25 | 408140 | Federal Highway | Att. EHC/TMD-5, p. 4 | NETPLANT | 6 | 4 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | 408300 | Tangible Property | Att. EHC/TMD-5, p. 4 | NETPLANT | 13 | 9 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 |
| 27 | 408400 | New Hampshire Business Enterprise Tax | Att. EHC/TMD-5, p. 4 | NETPLANT | 657 | 429 | 2 | 8 | 124 | 0 | 0 | 0 | 54 | 31 | 1 | 5 | 1 |
| 28 | 408500 | New Hampshire Consumption Tax | Att. EHC/TMD-5, p. 4 | NETPLANT | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 29 | 408600 | Insurance Premium Excise | Att. EHC/TMD-5, p. 4 | NETPLANT | 49 | 32 | 0 | 1 | 9 | 0 | 0 | 0 | 4 | 2 | 0 | 0 | 0 |
| 30 | | | | | | | | | | | | | | | | | |
| 31 | | **Total Other non-labor related taxes** | Sum of lines 25 to 29 | | **725** | **474** | **3** | **9** | **137** | **0** | **0** | **0** | **59** | **34** | **1** | **5** | **2** |
| 32 | | | | | | | | | | | | | | | | | |
| 33 | | **TOTAL TAXES OTHER THAN INCOME TAX** | Line 21 + Line 23 + Line 31 | | **52,537** | **34,371** | **182** | **663** | **9,888** | **25** | **16** | **17** | **4,280** | **2,462** | **105** | **397** | **132** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 11. INCOME TAXES**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Line | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | **INCOME TAXES** | | | | | | | | | | | | | | | |
| 11 | Total Distribution Revenue | Table 5, Line 28 | | 366,290 | 206,841 | 468 | 4,250 | 85,746 | 204 | 31 | 138 | 39,533 | 19,948 | 1,516 | 4,523 | 3,092 |
| 13 | Total Expense excluding income taxes | Table 1B | | 315,051 | 208,056 | 1,052 | 4,095 | 58,125 | 144 | 92 | 108 | 24,652 | 13,730 | 594 | 3,188 | 1,215 |
| 15 | Book Net Income Before Interest and Income Taxes | Line 11 + Line 13 | | 51,239 | (1,216) | (584) | 155 | 27,621 | 60 | (61) | 30 | 14,882 | 6,218 | 921 | 1,336 | 1,877 |
| 17 | Interest on Long Term Debt | | RBASE | (23,247) | (15,354) | (78) | (280) | (4,336) | (11) | (7) | (7) | (1,824) | (1,052) | (45) | (201) | (53) |
| 19 | Operating Income after Interest on LTD | Line 15 + Line 16 | | 27,991 | (16,570) | (662) | (125) | 23,285 | 50 | (68) | 23 | 13,058 | 5,166 | 877 | 1,134 | 1,823 |
| 21 | Permanent & Flowthrough Temporary Differences: | | | | | | | | | | | | | | | |
| 22 | PERMANENT DIFF_Total Gross Plant | | RBASE | 298 | 197 | 1 | 4 | 56 | 0 | 0 | 0 | 23 | 13 | 1 | 3 | 1 |
| 23 | Provision for uncollectible accounts | | UNCOL904 | 5,255 | 4,920 | - | - | 303 | - | - | - | 5 | 3 | - | 14 | 10 |
| 24 | Disallowed meals expense | | LABOR_D | 39 | 26 | 0 | 1 | 7 | 0 | 0 | 0 | 3 | 1 | 0 | 0 | 0 |
| 26 | PERMANENT & FLOW THROUGH DIFF(410-411) | Sum of Lines 22 to 24 | | 5,592 | 5,143 | 1 | 4 | 365 | 0 | 0 | 0 | 31 | 18 | 1 | 17 | 11 |
| 28 | NORMALIZED TIMING DIFF_Dist Gross Plant | Line 32 - 29 - 30 | RBASE | (47,112) | (31,116) | (158) | (567) | (8,787) | (21) | (14) | (15) | (3,696) | (2,131) | (90) | (408) | (108) |
| 29 | NORMALIZED TIMING DIFF_Labor | | O_LABOR | 30,851 | 20,328 | 111 | 460 | 5,701 | 14 | 9 | 13 | 2,387 | 1,261 | 56 | 314 | 196 |
| 30 | NORMALIZED TIMING DIFF_Uncollectibles | | UNCOL904 | (29) | (27) | - | - | (2) | - | - | - | (0) | (0) | - | (0) | (0) |
| 32 | NORMALIZED DIFF(410-411) | Sum of Lines 28 to 30 | | (16,290) | (10,815) | (47) | (107) | (3,087) | (7) | (5) | (2) | (1,309) | (871) | (34) | (94) | 88 |
| 34 | Sub Total-adj to Taxable Income | Line 26 + Line 32 | | (10,698) | (5,672) | (46) | (103) | (2,722) | (7) | (5) | (2) | (1,277) | (853) | (34) | (77) | 99 |
| 36 | Depreciation not Applicable State Inc. Tax | | DPLANT | (23,940) | (15,816) | (80) | (279) | (4,470) | (11) | (7) | (7) | (1,881) | (1,096) | (46) | (203) | (42) |
| 38 | Taxable Income For State Income Taxes | Line 34 + Line 36 | | (6,647) | (38,058) | (788) | (507) | 16,093 | 32 | (80) | 14 | 9,899 | 3,217 | 797 | 855 | 1,880 |
| 40 | NH State Tax eff. Tax rate | | | 0.077 | 0.077 | 0.077 | 0.077 | 0.077 | 0.077 | 0.077 | 0.077 | 0.077 | 0.077 | 0.077 | 0.077 | 0.077 |
| 41 | NH Income State Tax | Line 38 x Line 40 | | (512) | (2,930) | (61) | (39) | 1,239 | 2 | (6) | 1 | 762 | 248 | 61 | 66 | 145 |
| 43 | Taxable Income-Federal Tax | Line 36 + Line 38 | | 17,294 | (22,241) | (708) | (228) | 20,563 | 43 | (73) | 21 | 11,780 | 4,313 | 843 | 1,057 | 1,922 |
| 44 | Federal Taxable Income | Line 43 - Line 41 | | 17,805 | (19,311) | (647) | (189) | 19,324 | 40 | (67) | 20 | 11,018 | 4,065 | 782 | 992 | 1,778 |
| 46 | Federal Income Tax @21% | Line 44 x 21% | | 3,739 | (4,055) | (136) | (40) | 4,058 | 8 | (14) | 4 | 2,314 | 854 | 164 | 208 | 373 |
| 48 | **Total Current Federal & State Income Taxes** | Line 41 + Line 46 | | **3,227** | **(6,986)** | **(197)** | **(79)** | **5,297** | **11** | **(20)** | **5** | **3,076** | **1,101** | **225** | **274** | **518** |
| 50 | **DEFERRED INCOME TAXES** | | | | | | | | | | | | | | | |
| 52 | Total Deferred Income Taxes | Att. EHC/TMD-34, p. 2 | NETPLANT | 6,070 | 3,969 | 21 | 75 | 1,144 | 3 | 2 | 2 | 497 | 288 | 12 | 44 | 13 |
| 53 | Investment Tax Credit Adjustment | Att. EHC/TMD-5, p. 2 | NETPLANT | (4) | (2) | (0) | (0) | (1) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 55 | **Deferred Inc Tax & Net ITC** | Line 52 + Line 53 | | **6,067** | **3,966** | **21** | **75** | **1,144** | **3** | **2** | **2** | **496** | **288** | **12** | **44** | **13** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 12. OPERATIONS AND MAINTENANCE EXPENSES - PAYROLL COMPONENT**
**PRO FORMA TEST YEAR 2018**
**(in thousands)**

| Description | Reference | Pro Forma 12/31/2018 | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **OPERATIONS** | | | | | | | | | | | | | | | |
| 556 System Control And Load Dispatching | Sch. EHC/TMD-14, W/P 1 | 56 | 56 | 27 | 0 | 1 | 12 | 0 | 0 | 0 | 10 | 6 | 0 | 0 | 0 |
| 580 Operation Supervision And Engineering | Sch. EHC/TMD-14, W/P 1 | 8,672 | 8,672 | 5,342 | 33 | 122 | 1,635 | 5 | 3 | 3 | 848 | 512 | 25 | 89 | 57 |
| 581 Load Dispatching | Sch. EHC/TMD-14, W/P 1 | 888 | 888 | 428 | 5 | 11 | 189 | 1 | 0 | 0 | 155 | 94 | 3 | 1 | 1 |
| 582 Station Expenses | Sch. EHC/TMD-14, W/P 1 | 2,052 | 2,052 | 989 | 12 | 24 | 436 | 1 | 1 | 1 | 358 | 218 | 7 | 2 | 2 |
| 583 Overhead Line Expenses | Sch. EHC/TMD-14, W/P 1 | 751 | 751 | 471 | 2 | 8 | 139 | 0 | 0 | 0 | 76 | 47 | 2 | 2 | 2 |
| 584 Underground Line Expenses | Sch. EHC/TMD-14, W/P 1 | 334 | 334 | 235 | 2 | 7 | 66 | 0 | 0 | 0 | 13 | 8 | 0 | 1 | 1 |
| 585 Street Lighting And Signal System Expenses | Sch. EHC/TMD-14, W/P 1 | 385 | 385 | - | - | - | - | - | - | - | - | - | - | 235 | 150 |
| 586 Meter Expenses | Sch. EHC/TMD-14, W/P 1 | 1,948 | 1,948 | 1,305 | 12 | 117 | 458 | 3 | 1 | 3 | 44 | 4 | 1 | - | - |
| 587 Customer Installations Expenses | Sch. EHC/TMD-14, W/P 1 | 5 | 5 | 4 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 588 Miscellaneous Distribution Expenses | Sch. EHC/TMD-14, W/P 1 | 2,205 | 2,205 | 1,457 | 7 | 26 | 412 | 1 | 1 | 1 | 173 | 101 | 4 | 19 | 4 |
| 589 Distribution Operations Rent | Sch. EHC/TMD-14, W/P 1 | 231 | 231 | 179 | 0 | 1 | 36 | 0 | 0 | 0 | 8 | 5 | 0 | 1 | 1 |
| **MAINTENANCE** | | | | | | | | | | | | | | | |
| 590 Maintenance Supervising & Engineering | Sch. EHC/TMD-14, W/P 1 | 146 | 146 | 91 | 1 | 2 | 28 | 0 | 0 | 0 | 15 | 9 | 0 | 1 | 1 |
| 591 Maintenance Of Structures | Sch. EHC/TMD-14, W/P 1 | 144 | 144 | 95 | 0 | 2 | 27 | 0 | 0 | 0 | 11 | 7 | 0 | 1 | 0 |
| 592 Maintenance Of Station Equipment | Sch. EHC/TMD-14, W/P 1 | 1,133 | 1,133 | 546 | 6 | 13 | 241 | 1 | 1 | 0 | 198 | 120 | 4 | 1 | 1 |
| 593 Maintenance Of Overhead Lines | Sch. EHC/TMD-14, W/P 1 | 8,111 | 8,111 | 5,090 | 27 | 89 | 1,498 | 4 | 3 | 2 | 824 | 507 | 26 | 23 | 17 |
| 594 Maintenance Of Underground Lines | Sch. EHC/TMD-14, W/P 1 | 451 | 451 | 318 | 3 | 9 | 89 | 0 | 0 | 0 | 17 | 11 | 1 | 1 | 1 |
| 595 Maintenance Of Line Transformers | Sch. EHC/TMD-14, W/P 1 | 572 | 572 | 429 | 1 | 4 | 98 | 0 | 0 | 0 | 27 | 10 | 0 | 2 | 1 |
| 596 Maintenance Of Street Lighting And Signal Systems | Sch. EHC/TMD-14, W/P 1 | 45 | 45 | - | - | - | - | - | - | - | - | - | - | 27 | 17 |
| 597 Maintenance Of Meters | Sch. EHC/TMD-14, W/P 1 | 348 | 348 | 233 | 2 | 21 | 82 | 1 | 0 | 1 | 8 | 1 | 0 | - | - |
| 598 Maintenance Of Miscellaneous Distribution Plant | Sch. EHC/TMD-14, W/P 1 | 12 | 12 | 8 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 |
| Operations & Maintenance Expenses - Subtotal | Sum of lines 11 to 32 | **28,487** | **28,487** | **17,246** | **114** | **457** | **5,448** | **17** | **10** | **12** | **2,785** | **1,659** | **75** | **408** | **255** |
| **Operations & Maintenance Expenses - Customer** | | | | | | | | | | | | | | | |
| 901 Supervision | Sch. EHC/TMD-14, W/P 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 902 Meter Reading Expenses | Sch. EHC/TMD-14, W/P 1 | 1,906 | 1,906 | 1,384 | 29 | 135 | 264 | 2 | 2 | 4 | 79 | 6 | 1 | - | - |
| 903 Customer Records And Collection Expenses | Sch. EHC/TMD-14, W/P 1 | 9,111 | 9,111 | 7,183 | - | - | 1,623 | - | - | - | 281 | 23 | - | - | - |
| 905 Customer Account Expenses | Sch. EHC/TMD-14, W/P 1 | 63 | 63 | 59 | - | - | 4 | - | - | - | 0 | 0 | - | 0 | 0 |
| 908 Customer Assistance Expenses | Sch. EHC/TMD-14, W/P 1 | 546 | 546 | 440 | 1 | 4 | 85 | 0 | 0 | 0 | 15 | 1 | 0 | 0 | 0 |
| Operations & Maintenance Expenses - Customer Subtotal | Sum of lines 36 to 40 | **11,625** | **11,625** | **9,066** | **30** | **139** | **1,975** | **2** | **2** | **4** | **375** | **31** | **1** | **0** | **0** |
| **Administrative and General Expenses** | | | | | | | | | | | | | | | |
| 920 Administrative & General Salaries | Sch. EHC/TMD-14, W/P 1 | 14,049 | 14,049 | 9,373 | 50 | 212 | 2,586 | 6 | 4 | 6 | 1,032 | 525 | 23 | 143 | 89 |
| 925 Injuries & Damages | Sch. EHC/TMD-14, W/P 1 | 220 | 220 | 147 | 1 | 3 | 41 | 0 | 0 | 0 | 16 | 8 | 0 | 2 | 1 |
| 926 Employee Pension & Benefits | Sch. EHC/TMD-14, W/P 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 928 Regulatory Commission Expense | Sch. EHC/TMD-14, W/P 1 | 4 | 4 | 3 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 935 Maintenance of General Plant | Sch. EHC/TMD-14, W/P 1 | 111 | 111 | 73 | 0 | 2 | 21 | 0 | 0 | 0 | 9 | 5 | 0 | 1 | 1 |
| Operations & Maintenance Expenses - A&G Subtotal | Sum of lines 44 to 49 | **14,384** | **14,384** | **9,596** | **51** | **217** | **2,648** | **6** | **4** | **6** | **1,057** | **538** | **23** | **147** | **91** |
| **TOTAL PAYROLL EXPENSES** | Lines 33 + 41 + 49 | **54,497** | **54,497** | **35,909** | **196** | **813** | **10,071** | **25** | **16** | **22** | **4,217** | **2,227** | **99** | **555** | **347** |

1 **Public Service Company of New Hampshire, d/b/a Eversource Energy**
2 **Allocated Embedded Cost of Service Study**
3 **APPENDIX 1. EXTERNAL AND INTERNAL ALLOCATION FACTORS**
4 **PRO FORMA TEST YEAR 2018**

5 **Pro Forma Test Year**
6 OPTION FILTER

7 

| Line | DESCRIPTION | ALLOCATOR | TOTAL SYSTEM | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | <115 KV RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | **CP Allocators** | | 1,667,794.71 | 814,292.07 | 9,522.23 | 8,719.78 | 356,475.26 | 496.95 | 936.50 | 486.96 | 297,653.15 | 176,942.02 | 2,269.80 | - | - |
| 11 | Station-CP related | 20CP | 100.00% | 48.82% | 0.57% | 0.52% | 21.37% | 0.03% | 0.06% | 0.03% | 17.85% | 10.61% | 0.14% | - | - |
| 12 | | | 1,796,073.58 | 865,856.18 | 10,125.21 | 21,408.05 | 381,462.76 | 1,024.60 | 1,002.14 | 656.87 | 313,806.18 | 190,758.87 | 6,237.84 | 2,037.37 | 1,697.51 |
| 13 | 53% Bulk stat; 43% Dis. | 20CP/NCP_P | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 14 | | | | | | | | | | | | | | | |
| 15 | **NCP Allocators** | | | | | | | | | | | | | | |
| 16 | | | 1,940,728.49 | 924,002.95 | 10,805.17 | 35,716.09 | 409,640.15 | 1,619.61 | 1,076.16 | 848.48 | 332,021.31 | 206,339.56 | 10,712.44 | 4,334.83 | 3,611.73 |
| 17 | Demand-non station | NCP_P | 100.00% | 47.61% | 0.56% | 1.84% | 21.11% | 0.08% | 0.06% | 0.04% | 17.11% | 10.63% | 0.55% | 0.22% | 0.19% |
| 18 | | | 1,733,553.03 | 924,002.95 | 10,805.17 | 35,716.09 | 402,553.37 | 1,619.61 | 1,076.16 | 848.48 | 253,364.96 | 94,786.18 | 833.50 | 4,334.83 | 3,611.73 |
| 19 | Company-owned Xfmr | NCP_P_ADJ | 100.00% | 53.30% | 0.62% | 2.06% | 23.22% | 0.09% | 0.06% | 0.05% | 14.62% | 5.47% | 0.05% | 0.25% | 0.21% |
| 20 | | | 1,258,655.13 | 924,002.95 | 10,805.17 | 35,716.09 | 277,880.59 | 1,052.75 | 699.51 | 551.51 | - | - | - | 4,334.83 | 3,611.73 |
| 21 | Single phase D plant | NCP_P_1ph | 100.00% | 73.41% | 0.86% | 2.84% | 22.08% | 0.08% | 0.06% | 0.04% | - | - | - | 0.34% | 0.29% |
| 22 | | NCP_S_1ph | 100.00% | 73.41% | 0.86% | 2.84% | 22.08% | 0.08% | 0.06% | 0.04% | 0.00% | 0.00% | 0.00% | 0.34% | 0.29% |
| 23 | | | 1,259,895.61 | 924,002.95 | 10,805.17 | 35,716.09 | 277,880.59 | 1,619.61 | 1,076.16 | 848.48 | - | - | - | 4,334.83 | 3,611.73 |
| 24 | Secondary plant | NCP_S | 100.00% | 73.34% | 0.86% | 2.83% | 22.06% | 0.13% | 0.09% | 0.07% | - | - | - | 0.34% | 0.29% |
| 30 | | | 535.00 | - | - | - | - | - | - | - | - | - | - | 535.00 | |
| 31 | Streetlighting | CUST_371 | 100.00% | - | - | - | - | - | - | - | - | - | - | 100.00% | |
| 32 | Streetlighting | ST_DIRECT | 1.00 | - | - | - | - | - | - | - | - | - | - | 1.00 | - |
| 33 | Meter cost allocator | METER_370 | 100.00% | 67.00% | 0.62% | 6.01% | 23.54% | 0.15% | 0.03% | 0.18% | 2.25% | 0.18% | 0.03% | - | - |
| 34 | Meter plant weight | MTR_WF | 100.00% | 72.62% | 1.55% | 7.09% | 13.85% | 0.09% | 0.08% | 0.21% | 4.14% | 0.32% | 0.05% | - | - |
| 35 | | | | | | | | | | | | | | | |
| 36 | **Customer Allocators** | | | | | | | | | | | | | | |
| 37 | | | 519,578.20 | 440,810.80 | - | - | 76,487.00 | - | - | - | 1,383.40 | 106.00 | 18.00 | 535.00 | 238.00 |
| 38 | Customer-related | CUST_ALL | 100.00% | 84.84% | - | - | 14.72% | - | - | - | 0.27% | 0.02% | 0.00% | 0.10% | 0.05% |
| 39 | | | (6,372,372.00) | (2,926,586.00) | - | - | (3,228,828.00) | - | - | - | (138,474.73) | (72,669.26) | (5,798.00) | (9.32) | (6.68) |
| 40 | Customer deposit | CUST_235 | 100.00% | 45.93% | - | - | 50.67% | - | - | - | 2.17% | 1.14% | 0.09% | 0.00% | 0.00% |
| 41 | | | 547,273.26 | 440,810.80 | - | - | 106,206.69 | - | - | - | - | - | - | 77.91 | 177.87 |
| 42 | Services | SERV_369 | 100.00% | 80.55% | - | - | 19.41% | - | - | - | - | - | - | 0.01% | 0.03% |
| 43 | | | 522,073.99 | 440,810.80 | - | - | 76,487.00 | - | - | - | 1,383.40 | 106.00 | 18.00 | 1,973.03 | 1,295.76 |
| 44 | Customers | CUST_D | 100.00% | 84.43% | - | - | 14.65% | - | - | - | 0.26% | 0.02% | 0.00% | 0.38% | 0.25% |
| 45 | | | 500,667.92 | 440,810.80 | - | - | 56,588.33 | - | - | - | - | - | - | 1,973.03 | 1,295.76 |
| 46 | Single-phase cust | CUST_D_1ph | 100.00% | 88.04% | - | - | 11.30% | - | - | - | - | - | - | 0.39% | 0.26% |
| 47 | | | 520,349.13 | 440,810.80 | - | - | 75,163.77 | - | - | - | 1,055.67 | 48.69 | 1.40 | 1,973.03 | 1,295.76 |
| 48 | Transformer-customer | CUST_368 | 100.00% | 84.71% | - | - | 14.44% | - | - | - | 0.20% | 0.01% | 0.00% | 0.38% | 0.25% |
| 49 | | | 500,667.92 | 440,810.80 | - | - | 56,588.33 | - | - | - | - | - | - | 1,973.03 | 1,295.76 |
| 50 | Secondary customer | CUST_S | 100.00% | 88.04% | - | - | 11.30% | - | - | - | - | - | - | 0.39% | 0.26% |
| 51 | | | 50,269.88 | - | - | - | - | - | - | - | 46,430.47 | 3,839.41 | | | |
| 52 | Account 908 | CUS_908 | 100.00% | - | - | - | - | - | - | - | 92.36% | 7.64% | - | - | - |
| 53 | | | - | - | - | - | - | - | - | - | - | - | - | | |
| 54 | Uncollectible | UNCOL904 | 100.00% | 93.63% | - | - | 5.76% | - | - | - | 0.10% | 0.05% | - | 0.28% | 0.19% |
| 55 | | | | | | | | | | | | | | | |
| 56 | Account 903 | COLL903 | 100.00% | 78.85% | - | - | 17.81% | - | - | - | 3.09% | 0.26% | - | - | - |
| 57 | | | 7,889,479,674 | 3,144,970,835 | 36,776,884 | 92,916,119 | 1,716,678,138 | 5,451,861 | 4,509,879 | 3,379,300 | 1,665,675,827 | 1,172,438,767 | 18,134,625 | 17,231,142 | 11,316,297 |
| 58 | Sales kWh | ENERGY | 100.00% | 39.86% | 0.47% | 1.18% | 21.76% | 0.07% | 0.06% | 0.04% | 21.11% | 14.86% | 0.23% | 0.22% | 0.14% |
| 7 | | | | | | | | | | | | | | | **Page 18 of 20** |
| 8 | **Revenue Allocators** | | | | | | | | | | | | | | |
| 9 | | | 350,464,781 | 197,369,537 | 447,452 | 4,195,321 | 83,944,995 | 201,725 | 28,868 | 136,748 | 36,211,761 | 18,846,284 | 1,491,300 | 4,508,952 | 3,081,838 |
| 10 | Dist. Revenue | DREV | 100.00% | 56.32% | 0.13% | 1.20% | 23.95% | 0.06% | 0.01% | 0.04% | 10.33% | 5.38% | 0.43% | 1.29% | 0.88% |
| 11 | Revenue from Xfrm | TRANSF_454 | 100.00% | - | - | - | 0.24% | - | - | - | 78.69% | 20.80% | 0.27% | - | - |
| 12 | 451 Revenue | 451_Misc | 100.00% | 85.01% | - | - | 14.72% | - | - | - | 0.28% | - | - | - | - |
| 13 | 452 Revenue | 451_CC | 100.00% | 85.77% | - | - | 13.68% | - | - | - | 0.55% | - | - | - | - |
| 14 | 453 Revenue | 451_RR | 100.00% | 92.00% | - | - | 7.77% | - | - | - | 0.23% | - | - | - | - |
| 15 | 454 Revenue | 451_RC | 100.00% | 91.25% | - | - | 8.31% | - | - | - | 0.44% | - | - | - | - |
| 16 | Other revenue 451 | CUST_451 | 100.00% | 90.52% | - | - | 9.17% | - | - | - | 0.29% | 0.02% | 0.00% | 0.00% | - |
| 17 | | | | | | | | | | | | | | | |
| 18 | **INTERNAL ALLOCATORS** | | | | | | | | | | | | | | |
| 19 | **Operation & Maintenance Allocators** | | | | | | | | | | | | | | |
| 20 | | OM_581 | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 21 | | OM_582 | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 22 | | OM_583 | 100.00% | 62.75% | 0.33% | 1.10% | 18.48% | 0.05% | 0.03% | 0.03% | 10.16% | 6.25% | 0.33% | 0.29% | 0.21% |
| 23 | | OM_584 | 100.00% | 70.48% | 0.62% | 2.05% | 19.79% | 0.07% | 0.04% | 0.04% | 3.83% | 2.38% | 0.12% | 0.33% | 0.26% |
| 24 | | OM_585 | 100.00% | - | - | - | - | - | - | - | - | - | - | 61.08% | 38.92% |
| 25 | | OM_586 | 100.00% | 67.00% | 0.62% | 6.01% | 23.54% | 0.15% | 0.03% | 0.18% | 2.25% | 0.18% | 0.03% | - | - |
| 26 | | OM_587 | 100.00% | 72.22% | 0.22% | 2.09% | 19.97% | 0.05% | 0.01% | 0.06% | 0.78% | 0.06% | 0.01% | 4.49% | 0.02% |
| 27 | | OM_588 | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| 28 | | OM_589 | 100.00% | 77.45% | 0.13% | 0.44% | 15.65% | 0.02% | 0.01% | 0.01% | 3.50% | 2.09% | 0.11% | 0.35% | 0.24% |
| 29 | | OM_590 | 100.00% | 62.12% | 0.37% | 1.28% | 18.84% | 0.05% | 0.04% | 0.03% | 10.04% | 6.06% | 0.29% | 0.52% | 0.36% |
| 30 | | OM_591 | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| 31 | | OM_592 | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 32 | | OM_593 | 100.00% | 62.75% | 0.33% | 1.10% | 18.48% | 0.05% | 0.03% | 0.03% | 10.16% | 6.25% | 0.33% | 0.29% | 0.21% |
| 33 | | OM_594 | 100.00% | 70.48% | 0.62% | 2.05% | 19.79% | 0.07% | 0.04% | 0.04% | 3.83% | 2.38% | 0.12% | 0.33% | 0.26% |
| 34 | | OM_595 | 100.00% | 75.00% | 0.19% | 0.64% | 17.16% | 0.03% | 0.02% | 0.02% | 4.66% | 1.70% | 0.02% | 0.34% | 0.24% |
| 35 | | OM_596 | 100.00% | - | - | - | - | - | - | - | - | - | - | 61.08% | 38.92% |
| 36 | | OM_597 | 100.00% | 67.00% | 0.62% | 6.01% | 23.54% | 0.15% | 0.03% | 0.18% | 2.25% | 0.18% | 0.03% | - | - |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**APPENDIX 1. EXTERNAL AND INTERNAL ALLOCATION FACTORS**
**PRO FORMA TEST YEAR 2018**

**Pro Forma Test Year**
OPTION FILTER

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OM_598 | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| OM_901 | 100.00% | 77.98% | 0.26% | 1.20% | 16.99% | 0.02% | 0.01% | 0.04% | 3.23% | 0.26% | 0.01% | 0.00% | 0.00% |
| OM_902 | 100.00% | 72.62% | 1.55% | 7.09% | 13.85% | 0.09% | 0.08% | 0.21% | 4.14% | 0.32% | 0.05% | - | - |
| OM_903 | 100.00% | 78.85% | - | - | 17.81% | - | - | - | 3.09% | 0.26% | - | - | - |
| OM_905 | 100.00% | 93.63% | - | - | 5.76% | - | - | - | 0.10% | 0.05% | - | 0.28% | 0.19% |
| OM_908 | 100.00% | 80.53% | 0.15% | 0.71% | 15.53% | 0.01% | 0.01% | 0.02% | 2.73% | 0.23% | 0.01% | 0.04% | 0.03% |
| OM_ALL | 100.00% | 61.60% | 0.38% | 1.41% | 18.85% | 0.06% | 0.03% | 0.04% | 9.77% | 5.90% | 0.28% | 1.02% | 0.65% |
| | 24,996.27 | 15,724.63 | 70.77 | 312.73 | 4,988.79 | 12.28 | 6.02 | 8.72 | 2,247.38 | 1,219.99 | 65.37 | 214.11 | 125.47 |
| OM_PT | 100.00% | 62.91% | 0.28% | 1.25% | 19.96% | 0.05% | 0.02% | 0.03% | 8.99% | 4.88% | 0.26% | 0.86% | 0.50% |
| OM_PT property tax | 13,619.88 | 8,904.470 | 47.137 | 168.954 | 2,567.568 | 6.411 | 4.238 | 4.352 | 1,114.634 | 645.708 | 27.346 | 99.562 | 29.499 |
| % of PM_PT-payroll taxe | 573.74 | 378.042 | 2.061 | 8.558 | 106.027 | 0.264 | 0.169 | 0.234 | 44.399 | 23.444 | 1.044 | 5.843 | 3.653 |
| % of total PM_PT-taxes | | 56.63% | 66.61% | 54.02% | 51.47% | 52.19% | 70.38% | 49.92% | 49.60% | 52.93% | 41.83% | 46.50% | 23.51% |
| % of total PM_PT- payroll taxes | | 2.40% | 2.91% | 2.74% | 2.13% | 2.15% | 2.80% | 2.69% | 1.98% | 1.92% | 1.60% | 2.73% | 2.91% |
| % of total PM_PT-O&M | | 40.97% | 30.48% | 43.24% | 46.41% | 45.66% | 26.81% | 47.39% | 48.43% | 45.15% | 56.57% | 50.77% | 73.58% |
| | | | | | | | | | | | | | **Page 19 of 20** |
| **Other Internal Allocators** | | | | | | | | | | | | | |
| LATE | 100.00% | 81.12% | - | - | 13.38% | - | - | - | 3.55% | 1.85% | - | 0.06% | 0.04% |
| | 919,161.71 | 446,587.11 | | | 197,986.41 | | | | 189,709.30 | 72,609.32 | 3,769.54 | 4,636.55 | 3,863.49 |
| POWERF | 100.00% | 48.59% | - | - | 21.54% | - | - | - | 20.64% | 7.90% | 0.41% | 0.50% | 0.42% |
| | 306,248.38 | 147,637.08 | 1,726.45 | 3,650.28 | 65,043.19 | 174.70 | 170.87 | 112.00 | 53,507.07 | 32,526.28 | 1,063.61 | 347.39 | 289.44 |
| DIS_STATION | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| | 1,023,762.60 | 638,282.03 | 4,038.36 | 11,579.24 | 193,348.93 | 500.43 | 379.66 | 279.78 | 104,247.09 | 63,731.34 | 2,778.03 | 2,634.26 | 1,963.47 |
| NPLANT_OH | 100.00% | 62.35% | 0.39% | 1.13% | 18.89% | 0.05% | 0.04% | 0.03% | 10.18% | 6.23% | 0.27% | 0.26% | 0.19% |
| RBASE | 100.00% | 66.05% | 0.34% | 1.20% | 18.65% | 0.05% | 0.03% | 0.03% | 7.85% | 4.52% | 0.19% | 0.87% | 0.23% |
| | 582,095.62 | 365,281.80 | 1,931.86 | 6,385.68 | 107,544.87 | 289.57 | 192.41 | 151.70 | 59,117.83 | 36,400.08 | 1,895.40 | 1,670.56 | 1,233.87 |
| OH_LINE | 100.00% | 62.75% | 0.33% | 1.10% | 18.48% | 0.05% | 0.03% | 0.03% | 10.16% | 6.25% | 0.33% | 0.29% | 0.21% |
| | 172,499.49 | 121,578.09 | 1,071.38 | 3,541.42 | 34,130.44 | 115.64 | 76.84 | 60.58 | 6,602.94 | 4,099.17 | 212.89 | 563.91 | 446.18 |
| UG_LINE | 100.00% | 70.48% | 0.62% | 2.05% | 19.79% | 0.07% | 0.04% | 0.04% | 3.83% | 2.38% | 0.12% | 0.33% | 0.26% |
| DIRECT ST | - | - | - | - | - | - | - | - | - | - | - | 61.08% | 38.92% |
| | 90,764.20 | 60,815.87 | 565.26 | 5,451.64 | 21,365.37 | 138.72 | 30.85 | 160.93 | 2,042.16 | 165.94 | 27.47 | - | - |
| MET_PLANT | 100.00% | 67.00% | 0.62% | 6.01% | 23.54% | 0.15% | 0.03% | 0.18% | 2.25% | 0.18% | 0.03% | - | - |
| | 260,810.97 | 188,363.61 | 565.26 | 5,451.64 | 52,096.07 | 138.72 | 30.85 | 160.93 | 2,042.16 | 165.94 | 27.47 | 11,716.86 | 51.47 |
| D_PLANT_587 | 100.00% | 72.22% | 0.22% | 2.09% | 19.97% | 0.05% | 0.01% | 0.06% | 0.78% | 0.06% | 0.01% | 4.49% | 0.02% |
| | 303,587.83 | 235,116.11 | 404.26 | 1,336.25 | 47,511.48 | 60.59 | 40.26 | 31.74 | 10,637.18 | 6,332.15 | 333.36 | 1,059.81 | 724.63 |
| POL_PLANT | 100.00% | 77.45% | 0.13% | 0.44% | 15.65% | 0.02% | 0.01% | 0.01% | 3.50% | 2.09% | 0.11% | 0.35% | 0.24% |
| | 257,940.23 | 193,453.11 | 497.22 | 1,643.56 | 44,260.39 | 74.53 | 49.52 | 39.04 | 12,020.63 | 4,378.48 | 38.83 | 875.04 | 609.87 |
| TRANSF_PLANT | 100.00% | 75.00% | 0.19% | 0.64% | 17.16% | 0.03% | 0.02% | 0.02% | 4.66% | 1.70% | 0.02% | 0.34% | 0.24% |
| | 79,773.43 | 42,520.12 | 497.22 | 1,643.56 | 18,524.42 | 74.53 | 49.52 | 39.04 | 11,659.17 | 4,361.80 | 38.36 | 199.48 | 166.20 |
| TRANSF_PLANT_NCP | 100.00% | 53.30% | 0.62% | 2.06% | 23.22% | 0.09% | 0.06% | 0.05% | 14.62% | 5.47% | 0.05% | 0.25% | 0.21% |
| | 178,166.80 | 150,932.99 | - | - | 25,735.97 | - | - | - | 361.46 | 16.67 | 0.48 | 675.56 | 443.67 |
| TRANSF_PLANT_CUST | 100.00% | 84.71% | - | - | 14.44% | - | - | - | 0.20% | 0.01% | 0.00% | 0.38% | 0.25% |
| SHARE OF NCP | | 21.98% | | | 41.85% | 100.00% | | | 96.99% | 99.62% | 98.77% | 22.80% | 27.25% |
| | 1,924,064.47 | 1,271,155.45 | 6,401.30 | 22,442.00 | 359,282.90 | 874.49 | 581.03 | 569.29 | 151,214.46 | 88,120.55 | 3,716.40 | 16,297.71 | 3,408.90 |
| DPLANT | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| | 22,757.98 | 18,102.46 | 34.77 | 159.58 | 3,491.48 | 2.02 | 1.90 | 4.71 | 870.60 | 72.95 | 1.22 | 9.68 | 6.62 |
| CUST EXP_ALL | 100.00% | 79.54% | 0.15% | 0.70% | 15.34% | 0.01% | 0.01% | 0.02% | 3.83% | 0.32% | 0.01% | 0.04% | 0.03% |
| | 79,585.01 | 50,007.37 | 305.17 | 1,145.84 | 15,300.39 | 45.23 | 28.32 | 29.29 | 7,933.25 | 4,790.15 | - | - | - |
| DISTOMEXP | 100.00% | 62.84% | 0.38% | 1.44% | 19.23% | 0.06% | 0.04% | 0.04% | 9.97% | 6.02% | - | - | - |
| | 885,683.45 | 600,397.91 | 2,336.11 | 7,721.93 | 155,056.34 | 350.16 | 232.67 | 183.44 | 69,755.01 | 42,732.23 | 2,228.76 | 2,730.37 | 1,958.50 |
| OHPLANT | 100.00% | 67.79% | 0.26% | 0.87% | 17.51% | 0.04% | 0.03% | 0.02% | 7.88% | 4.82% | 0.25% | 0.31% | 0.22% |
| OHPLANT_ncp | | 199,772.42 | 2,336.11 | 7,721.93 | 87,310.14 | 350.16 | 232.67 | 183.44 | 68,620.64 | 42,645.32 | 2,214.00 | 937.20 | 780.87 |
| OHPLANT_CUST | | 400,625.49 | - | - | 67,746.20 | - | - | - | 1,134.37 | 86.92 | 14.76 | 1,793.17 | 1,177.64 |
| | 1,213,327.61 | 738,466.23 | 4,379.11 | 12,174.52 | 228,717.90 | 562.34 | 434.94 | 317.51 | 136,214.44 | 83,217.42 | 3,631.47 | 2,999.80 | 2,211.92 |
| DPLANT_P | 100.00% | 60.86% | 0.36% | 1.00% | 18.85% | 0.05% | 0.04% | 0.03% | 11.23% | 6.86% | 0.30% | 0.25% | 0.18% |
| | 342,589.41 | 165,156.46 | 1,931.32 | 4,083.45 | 72,761.55 | 195.44 | 191.15 | 125.29 | 59,856.50 | 36,386.02 | 1,189.83 | 388.61 | 323.79 |
| DPLANT_P_CP | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| | | | | | | | | | | | | | **Page 20 of 20** |
| **Other Internal Allocators** | | | | | | | | | | | | | |
| | 439,649.92 | 209,322.34 | 2,447.79 | 8,091.07 | 92,799.31 | 366.90 | 243.79 | 192.21 | 75,215.64 | 46,743.88 | 2,426.78 | 982.01 | 818.20 |
| DPLANT_P_NCP | 100.00% | 47.61% | 0.56% | 1.84% | 21.11% | 0.08% | 0.06% | 0.04% | 17.11% | 10.63% | 0.55% | 0.22% | 0.19% |
| | 431,088.29 | 363,987.44 | - | - | 63,157.04 | - | - | - | 1,142.30 | 87.53 | 14.86 | 1,629.18 | 1,069.94 |
| DPLANT_P_CUST | 100.00% | 84.43% | - | - | 14.65% | - | - | - | 0.26% | 0.02% | 0.00% | 0.38% | 0.25% |
| | 158,352.45 | 127,547.74 | - | - | 30,730.70 | - | - | - | - | - | - | 22.54 | 51.47 |
| CUS_369 | 100.00% | 80.55% | - | - | 19.41% | - | - | - | - | - | - | 0.01% | 0.03% |
| | 22,341.53 | 17,991.97 | 34.56 | 158.62 | 3,470.18 | 2.01 | 1.89 | 4.68 | 608.91 | 51.31 | 1.21 | 9.62 | 6.58 |
| MIS_CUST XP | 100.00% | 80.53% | 0.15% | 0.71% | 15.53% | 0.01% | 0.01% | 0.02% | 2.73% | 0.23% | 0.01% | 0.04% | 0.03% |
| NETPLANT | 100.00% | 65.38% | 0.35% | 1.24% | 18.85% | 0.05% | 0.03% | 0.03% | 8.18% | 4.74% | 0.20% | 0.73% | 0.22% |
| NETPLANT-CP | 100.00% | 48.63% | 0.56% | 1.17% | 21.19% | 0.06% | 0.06% | 0.04% | 17.30% | 10.47% | 0.34% | 0.11% | 0.09% |
| NETPLANT-NCP | 100.00% | 52.54% | 0.61% | 2.01% | 21.48% | 0.08% | 0.06% | 0.04% | 14.05% | 8.28% | 0.40% | 0.25% | 0.20% |
| NETPLANT-CUST | 100.00% | 80.81% | 0.08% | 0.75% | 16.13% | 0.02% | 0.00% | 0.02% | 0.55% | 0.04% | 0.01% | 1.31% | 0.27% |
| | 52,960.12 | 34,895.96 | 190.27 | 789.96 | 9,787.02 | 24.41 | 15.57 | 21.64 | 4,098.36 | 2,164.00 | 96.36 | 539.38 | 337.20 |

1 **Public Service Company of New Hampshire, d/b/a Eversource Energy**
2 **Allocated Embedded Cost of Service Study**
3 **APPENDIX 1. EXTERNAL AND INTERNAL ALLOCATION FACTORS**
4 **PRO FORMA TEST YEAR 2018**
5 **Pro Forma Test Year**
6 OPTION FILTER

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25 | INTPLANT | 100.00% | 65.89% | 0.36% | 1.49% | 18.48% | 0.05% | 0.03% | 0.04% | 7.74% | 4.09% | 0.18% | 1.02% | 0.64% |
| 26 | | 9,953.05 | 4,798.20 | 56.11 | 118.63 | 2,113.90 | 5.68 | 5.55 | 3.64 | 1,738.98 | 1,057.10 | 34.57 | 11.29 | 9.41 |
| 27 | LANDPLANT | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 28 | | 26,387.98 | 12,721.19 | 148.76 | 314.53 | 5,604.46 | 15.05 | 14.72 | 9.65 | 4,610.45 | 2,802.64 | 91.65 | 29.93 | 24.94 |
| 29 | STRPLANT | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 30 | | 194,020.81 | 127,842.27 | 697.05 | 2,894.03 | 35,855.02 | 89.43 | 57.05 | 79.28 | 15,014.43 | 7,927.88 | 353.02 | 1,976.03 | 1,235.33 |
| 31 | GENPLANT | 100.00% | 65.89% | 0.36% | 1.49% | 18.48% | 0.05% | 0.03% | 0.04% | 7.74% | 4.09% | 0.18% | 1.02% | 0.64% |
| 32 | AG_920 | 100.00% | 66.72% | 0.36% | 1.51% | 18.41% | 0.04% | 0.03% | 0.04% | 7.34% | 3.73% | 0.16% | 1.02% | 0.63% |
| 33 | AG_925 | 100.00% | 66.72% | 0.36% | 1.51% | 18.41% | 0.04% | 0.03% | 0.04% | 7.34% | 3.73% | 0.16% | 1.02% | 0.63% |
| 34 | AG_926 | 100.00% | 66.72% | 0.36% | 1.51% | 18.41% | 0.04% | 0.03% | 0.04% | 7.34% | 3.73% | 0.16% | 1.02% | 0.63% |
| 35 | AG_928 | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| 36 | AG_935 | 100.00% | 65.89% | 0.36% | 1.49% | 18.48% | 0.05% | 0.03% | 0.04% | 7.74% | 4.09% | 0.18% | 1.02% | 0.64% |
| 37 | LABOR_D | 100.00% | 66.72% | 0.36% | 1.51% | 18.41% | 0.04% | 0.03% | 0.04% | 7.34% | 3.73% | 0.16% | 1.02% | 0.63% |
| 38 | LABOR_D_O | 100.00% | 57.54% | 0.47% | 2.20% | 19.75% | 0.07% | 0.04% | 0.06% | 9.46% | 5.45% | 0.21% | 2.96% | 1.80% |
| 39 | LABOR_D_M | 100.00% | 62.12% | 0.37% | 1.28% | 18.84% | 0.05% | 0.04% | 0.03% | 10.04% | 6.06% | 0.29% | 0.52% | 0.36% |
| 40 | O_LABOR | 100.00% | 65.89% | 0.36% | 1.49% | 18.48% | 0.05% | 0.03% | 0.04% | 7.74% | 4.09% | 0.18% | 1.02% | 0.64% |
| 41 | | 26,387.98 | 12,721.19 | 148.76 | 314.53 | 5,604.46 | 15.05 | 14.72 | 9.65 | 4,610.45 | 2,802.64 | 91.65 | 29.93 | 24.94 |
| 42 | STRUCT_D | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |

# PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
# D/B/A EVERSOURCE ENERGY
# ALLOCATED DISTRIBUTION COST OF SERVICE STUDY

## Per Books Test Year 2018

**Permanent Filing**

**May 28, 2019**

Economists
INCORPORATED

**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE**
**D/B/A EVERSOURCE ENERGY**
**ALLOCATED DISTRIBUTION COST OF SERVICE STUDY**

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**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 1-A. DISTRIBUTION REVENUE REQUIREMENT AND REQUIRED RATE CHANGE BY RATE CLASS**
**Per Books Test Year 2018**
**(in thousands)**

| Line | Description | Reference | Test Year 12/31/2018 Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | Rate base | Table 1B, Line 15 | 1,219,367 | 798,511 | 4,241 | 15,232 | 227,342 | 578 | 381 | 393 | 100,404 | 58,134 | 2,465 | 8,991 | 2,695 |
| 12 | Operating income | Table 1B, Line 36 | 53,752 | 9,987 | (369) | 319 | 23,286 | 51 | (39) | 27 | 12,014 | 5,190 | 696 | 1,193 | 1,397 |
| 14 | Earned rate of return | Table 1B, Line 38 | 4.41% | 1.25% | -8.71% | 2.10% | 10.24% | 8.89% | -10.31% | 6.97% | 11.97% | 8.93% | 28.22% | 13.26% | 51.83% |
| 16 | Requested rate of return/cost of capital | Sch. EHC/TMD-3 | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% |
| 18 | Required operating income | Line 11 x Line 16 | 86,346 | 56,544 | 300 | 1,079 | 16,099 | 41 | 27 | 28 | 7,110 | 4,117 | 175 | 637 | 191 |
| 19 | Income sufficiency/(deficiency) | Line 12 - Line 18 | (32,594) | (46,557) | (670) | (759) | 7,187 | 10 | (66) | (0) | 4,904 | 1,074 | 521 | 556 | 1,206 |
| 21 | Gross revenue conversion factor | Sch. EHC/TMD-2 | 1.37440 | 1.37440 | 1.37440 | 1.37440 | 1.37440 | 1.37440 | 1.37440 | 1.37440 | 1.37440 | 1.37440 | 1.37440 | 1.37440 | 1.37440 |
| 22 | Revenue increase/(decrease) | Line 19 x Line 21 | 44,798 | 63,988 | 920 | 1,044 | (9,878) | (14) | 91 | 1 | (6,740) | (1,475) | (716) | (764) | (1,657) |
| 24 | Net write-off as a % of retail revenue | Att. EHC/TMD-2, W/P 8 | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% | 0.66% |
| 25 | Uncollectible adjustment | Line 22 x Line 24 | 294 | 420 | 6 | 7 | (65) | (0) | 1 | 0 | (44) | (10) | (5) | (5) | (11) |
| 27 | **Revenue increase/(decrease)** | Ties to Sch. EHC/TMD-1 | **45,092** | **64,409** | **926** | **1,050** | **(9,943)** | **(14)** | **92** | **1** | **(6,784)** | **(1,485)** | **(721)** | **(769)** | **(1,668)** |
| 30 | Distribution Revenue Requirement | Table 5, Line 28 | $ 410,714 | $ 270,665 | $ 1,395 | $ 5,300 | $ 75,724 | $ 190 | $ 123 | $ 139 | $ 32,745 | $ 18,462 | $ 794 | $ 3,754 | $ 1,424 |
| 31 | Other Revenue | Table 5, Line 26 | 15,760 | $ 9,227 | $ 21 | $ 62 | $ 1,867 | $ 3 | $ 2 | $ 2 | $ 3,380 | $ 1,134 | $ 27 | $ 22 | $ 15 |
| 33 | **Net Distribution Revenue Requirement** | Line 30 - Line 31 | **394,954** | **$ 261,439** | **$ 1,373** | **$ 5,239** | **$ 73,857** | **$ 187** | **$ 121** | **$ 137** | **$ 29,365** | **$ 17,329** | **$ 768** | **$ 3,732** | **$ 1,408** |
| 35 | Current Distribution Revenues | Table 5, Line 12 | 349,862 | $ 197,030 | $ 447 | $ 4,188 | $ 83,801 | $ 201 | $ 29 | $ 137 | $ 36,149 | $ 18,814 | $ 1,489 | $ 4,501 | $ 3,077 |
| 37 | **Required Change in Rates** | Line 33 / Line 35 - 1 | **12.89%** | **32.69%** | **207.39%** | **25.08%** | **-11.87%** | **-7.18%** | **318.15%** | **0.43%** | **-18.768%** | **-7.894%** | **-48.43%** | **-17.09%** | **-54.23%** |

39 BREAKDOWN OF REVENUE REQUIREMENT

| Line | | | Total | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41 | | Demand-CP | 64,113 | 31,279 | 367 | 764 | 13,485 | 36 | 36 | 23 | 11,055 | 6,725 | 214 | 69 | 59 |
| 42 | | Demand-NCP | 133,017 | 70,215 | 820 | 2,709 | 28,967 | 115 | 77 | 61 | 17,533 | 11,350 | 583 | 315 | 273 |
| 43 | | Customer | 222,645 | 176,745 | 267 | 2,094 | 35,942 | 47 | 15 | 62 | 2,474 | 167 | 7 | 3,656 | 1,170 |
| 44 | | | **419,775** | **278,239** | **1,455** | **5,567** | **78,393** | **198** | **127** | **146** | **31,063** | **18,242** | **804** | **4,040** | **1,502** |

1 **Public Service Company of New Hampshire, d/b/a Eversource Energy**
2 **Allocated Embedded Cost of Service Study**
3 **TABLE 1-B CURRENT AND REQUIRED RETURN ON RATE BASE BY RATE CLASS**
4 **Per Books Test Year 2018**
5 **(in thousands)**
6

| Line | Description | Reference | 12/31/2018 Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | | | | | | | |
| 10 | **RATE BASE** | | | | | | | | | | | | | | |
| 11 | Net Plant | Table 4, Line 16 | 1,568,619 | 1,025,539 | 5,429 | 19,459 | 295,710 | 738 | 488 | 501 | 128,374 | 74,367 | 3,150 | 11,467 | 3,397 |
| 12 | Total Rate Base Deductions | Table 4, Line 24 | (378,209) | (245,633) | (1,280) | (4,587) | (73,972) | (174) | (115) | (118) | (30,447) | (17,628) | (750) | (2,703) | (801) |
| 13 | Total Rate Base Additions | Table 4, Line 32 | 28,957 | 18,605 | 92 | 360 | 5,603 | 14 | 8 | 10 | 2,478 | 1,395 | 66 | 227 | 98 |
| 14 | | | | | | | | | | | | | | | |
| 15 | TOTAL RATE BASE | Sum of Lines 11 to 13 | 1,219,367 | 798,511 | 4,241 | 15,232 | 227,342 | 578 | 381 | 393 | 100,404 | 58,134 | 2,465 | 8,991 | 2,695 |
| 16 | | | | | | | | | | | | | | | |
| 17 | TOTAL OPERATING REVENUE | Table 5, Line 28 | 365,622 | 206,257 | 468 | 4,250 | 85,667 | 204 | 31 | 138 | 39,529 | 19,947 | 1,516 | 4,523 | 3,092 |
| 18 | | | | | | | | | | | | | | | |
| 19 | **OPERATION & MAINTENANCE EXPENSE** | | | | | | | | | | | | | | |
| 20 | Distr. O&M Expense and misc. Production | Table 6, Line 41 | 83,788 | 51,727 | 312 | 1,156 | 15,761 | 46 | 29 | 29 | 8,211 | 4,968 | 240 | 797 | 511 |
| 21 | Customer Accounting Expenses | Table 7, Line 19 | 19,661 | 15,734 | 32 | 148 | 3,124 | 2 | 2 | 4 | 556 | 46 | 1 | 7 | 5 |
| 22 | Customer Svc. & Information/Sales Expenses | Table 7, Line 26 + Line 33 | 280 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 256 | 21 | 0 | 0 | 0 |
| 23 | Administrative & General Expenses | Table 8, Line 26 | 59,072 | 39,103 | 211 | 863 | 10,943 | 27 | 17 | 24 | 4,555 | 2,418 | 87 | 521 | 304 |
| 24 | Total Depreciation Expense | Table 9, Line 47 | 62,325 | 41,824 | 195 | 799 | 11,577 | 28 | 17 | 21 | 4,191 | 2,381 | 103 | 1,046 | 144 |
| 25 | Total Amortization Expense | Table 9, Line 51 | 15,815 | 10,445 | 53 | 190 | 2,950 | 7 | 5 | 5 | 1,241 | 715 | 30 | 137 | 36 |
| 26 | EESCO Depreciation / Amortization | Table 9, Line 52 | 5,062 | 3,343 | 17 | 61 | 944 | 2 | 2 | 2 | 397 | 229 | 10 | 44 | 12 |
| 27 | Property Tax Expense | Table 10, Line 23 | 47,118 | 30,805 | 163 | 584 | 8,882 | 22 | 15 | 15 | 3,856 | 2,234 | 95 | 344 | 102 |
| 28 | Payroll and Other Taxes | Table 10, Line 21 + Line 31 | 4,745 | 3,123 | 17 | 69 | 880 | 2 | 1 | 2 | 370 | 199 | 9 | 46 | 27 |
| 29 | TOTAL EXPENSE BEFORE INCOME TAXES | | 297,866 | 196,106 | 999 | 3,871 | 55,060 | 137 | 87 | 102 | 23,634 | 13,212 | 575 | 2,942 | 1,140 |
| 30 | | | | | | | | | | | | | | | |
| 31 | Federal and State Income Taxes | Table 11, Line 48 | 7,978 | (3,777) | (183) | (15) | 6,185 | 13 | (19) | 7 | 3,388 | 1,259 | 232 | 345 | 542 |
| 32 | Deferred Income Tax Expense | Table 11, Line 52 | 6,030 | 3,943 | 21 | 75 | 1,137 | 3 | 2 | 2 | 494 | 286 | 12 | 44 | 13 |
| 33 | Investment Tax Credit | Table 11, Line 53 | (4) | (2) | (0) | (0) | (1) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 34 | OPERATING EXPENSES INCLUDING INCOME TAX | | 311,871 | 196,270 | 837 | 3,930 | 62,381 | 153 | 70 | 111 | 27,515 | 14,757 | 820 | 3,331 | 1,695 |
| 35 | | | | | | | | | | | | | | | |
| 36 | OPERATING INCOME | Line 17 - Line 34 | 53,752 | 9,987 | (369) | 319 | 23,286 | 51 | (39) | 27 | 12,014 | 5,190 | 696 | 1,193 | 1,397 |
| 37 | | | | | | | | | | | | | | | |
| 38 | **REALIZED RETURN ON RATE BASE** | Line 36 / Line 15 | **4.4%** | **1.3%** | **-8.7%** | **2.1%** | **10.2%** | **8.9%** | **-10.3%** | **7.0%** | **12.0%** | **8.9%** | **28.2%** | **13.3%** | **51.8%** |
| 39 | | | | | | | | | | | | | | | |
| 40 | **REQUIRED RETURN ON RATE BASE** | Sch. EHC/TMD-3 | **7.08%** | **7.08%** | **7.08%** | **7.08%** | **7.08%** | **7.08%** | **7.08%** | **7.08%** | **7.08%** | **7.08%** | **7.08%** | **7.08%** | **7.08%** |
| 41 | | | | | | | | | | | | | | | |
| 42 | **REQUIRED OPERATING INCOME** | Line 40 * Line 15 | **86,346** | **56,544** | **300** | **1,079** | **16,099** | **41** | **27** | **28** | **7,110** | **4,117** | **175** | **637** | **191** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 2. GROSS PLANT IN SERVICE**
**Per Books Test Year 2018**
**(in thousands)**

| Line | Minimum System % | Account | Description | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | | | | | | | | | |
| 10 | | | **INTANGIBLE PLANT** | | | | | | | | | | | | | | |
| 11 | | 301 | Organization Intangible Plant | O_LABOR | 45 | 30 | 0 | 1 | 8 | 0 | 0 | 0 | 3 | 2 | 0 | 0 | 0 |
| 12 | | 303 | Miscellaneous Intangible Plant | O_LABOR | 52,915 | 34,866 | 190 | 789 | 9,779 | 24 | 16 | 22 | 4,095 | 2,162 | 96 | 539 | 337 |
| 13 | | | | | | | | | | | | | | | | | |
| 14 | | | **Total Intangible Plant In service (sum of lines 11 to 12)** | | **52,960** | **34,896** | **190** | **790** | **9,787** | **24** | **16** | **22** | **4,098** | **2,164** | **96** | **539** | **337** |
| 15 | | | | | | | | | | | | | | | | | |
| 16 | | | **DISTRIBUTION PLANT** | | | | | | | | | | | | | | |
| 17 | | 360 | Land & Land Rights | 20CP/NCP_P | 9,953 | 4,798 | 56 | 119 | 2,114 | 6 | 6 | 4 | 1,739 | 1,057 | 35 | 11 | 9 |
| 18 | | 361 | Structures & Improvements | 20CP/NCP_P | 26,388 | 12,721 | 149 | 315 | 5,604 | 15 | 15 | 10 | 4,610 | 2,803 | 92 | 30 | 25 |
| 19 | | 362 | Station Equipment | 20CP/NCP_P | 306,248 | 147,637 | 1,726 | 3,650 | 65,043 | 175 | 171 | 112 | 53,507 | 32,526 | 1,064 | 347 | 289 |
| 20 | | | | | | | | | | | | | | | | | |
| 21 | | 364 | **Poles, Towers, & Fixtures** | | | | | | | | | | | | | | |
| 22 | 19.50% | 364 | Primary-Demand | NCP_P | 59,189 | 28,180 | 330 | 1,089 | 12,493 | 49 | 33 | 26 | 10,126 | 6,293 | 327 | 132 | 110 |
| 23 | 63.54% | 364 | Primary Customer | CUST_D | 192,888 | 162,864 | - | - | 28,259 | - | - | - | 511 | 39 | 7 | 729 | 479 |
| 24 | 2.87% | 364 | Secondary-Demand | NCP_S | 8,712 | 6,389 | 75 | 247 | 1,922 | 11 | 7 | 6 | - | - | - | 30 | 25 |
| 25 | 14.10% | 364 | Secondary-Customer | CUST_S | 42,799 | 37,682 | - | - | 4,837 | - | - | - | - | - | - | 169 | 111 |
| 26 | | 364 | **Total (sum of lines 22 to 25)** | | **303,588** | **235,116** | **404** | **1,336** | **47,511** | **61** | **40** | **32** | **10,637** | **6,332** | **333** | **1,060** | **725** |
| 27 | | | | | | | | | | | | | | | | | |
| 28 | | 365 | **OH Conductor & Devices** | | | | | | | | | | | | | | |
| 29 | 58.74% | 365 | OH Primary-Demand | NCP_P | 341,912 | 162,788 | 1,904 | 6,292 | 72,169 | 285 | 190 | 149 | 58,495 | 36,352 | 1,887 | 764 | 636 |
| 30 | 40.41% | 365 | OH Primary-Customer | CUST_D | 235,204 | 198,593 | - | - | 34,459 | - | - | - | 623 | 48 | 8 | 889 | 584 |
| 31 | 0.57% | 365 | OH Secondary-Demand | NCP_S | 3,292 | 2,414 | 28 | 93 | 726 | 4 | 3 | 2 | - | - | - | 11 | 9 |
| 32 | 0.29% | 365 | OH Secondary-Customer | CUST_S | 1,688 | 1,486 | - | - | 191 | - | - | - | - | - | - | 7 | 4 |
| 33 | | 365 | **Total (sum of lines 29 to 32)** | | **582,096** | **365,282** | **1,932** | **6,386** | **107,545** | **290** | **192** | **152** | **59,118** | **36,400** | **1,895** | **1,671** | **1,234** |
| 34 | | | | | | | | | | | | | | | | | |
| 35 | | 366 | **UG Conduit** | | | | | | | | | | | | | | |
| 36 | 22.35% | 366 | Primary-Demand -polyphase | NCP_P | 8,661 | 4,124 | 48 | 159 | 1,828 | 7 | 5 | 4 | 1,482 | 921 | 48 | 19 | 16 |
| 37 | 46.58% | 366 | Primary-Demand - single phase | NCP_P_1ph | 18,052 | 13,252 | 155 | 512 | 3,985 | 15 | 10 | 8 | - | - | - | 62 | 52 |
| 38 | 1.74% | 366 | Primary-Customer - polyphase | CUST_D | 673 | 568 | - | - | 99 | - | - | - | 2 | 0 | 0 | 3 | 2 |
| 39 | 10.03% | 366 | Primary-Customer - single phase | CUST_D_1ph | 3,888 | 3,423 | - | - | 439 | - | - | - | - | - | - | 15 | 10 |
| 40 | 11.28% | 366 | Secondary-Demand - single phase | NCP_S_1ph | 4,371 | 3,209 | 38 | 124 | 965 | 4 | 2 | 2 | - | - | - | 15 | 13 |
| 41 | 8.03% | 366 | Secondary-Customer single phase | CUST_D_1ph | 3,112 | 2,740 | - | - | 352 | - | - | - | - | - | - | 12 | 8 |
| 42 | | 366 | **Total (sum of lines 36 to 41)** | | **38,758** | **27,317** | **241** | **796** | **7,669** | **26** | **17** | **14** | **1,484** | **921** | **48** | **127** | **100** |
| 43 | | | | | | | | | | | | | | | | | |
| 44 | | 367 | **UG Conductor & Devices** | | | | | | | | | | | | | | |
| 45 | 22.35% | 367 | Primary-Demand -polyphase | NCP_P | 29,888 | 14,230 | 166 | 550 | 6,309 | 25 | 17 | 13 | 5,113 | 3,178 | 165 | 67 | 56 |
| 46 | 46.58% | 367 | Primary-Demand -single phase | NCP_P_1ph | 62,293 | 45,730 | 535 | 1,768 | 13,753 | 52 | 35 | 27 | - | - | - | 215 | 179 |
| 47 | 1.74% | 367 | Primary-Customer - polyphase | CUST_D | 2,323 | 1,961 | - | - | 340 | - | - | - | 6 | 0 | 0 | 9 | 6 |
| 48 | 10.03% | 367 | Primary-Customer - single phase | CUST_D_1ph | 13,417 | 11,813 | - | - | 1,516 | - | - | - | - | - | - | 53 | 35 |
| 49 | 11.28% | 367 | Secondary-Demand | NCP_S_1ph | 15,084 | 11,074 | 129 | 428 | 3,330 | 13 | 8 | 7 | - | - | - | 52 | 43 |
| 50 | 8.03% | 367 | Secondary-Customer | CUST_D_1ph | 10,737 | 9,453 | - | - | 1,214 | - | - | - | - | - | - | 42 | 28 |
| 51 | | 367 | **Total (sum of lines 45 to 50)** | | **133,742** | **94,262** | **831** | **2,746** | **26,462** | **90** | **60** | **47** | **5,119** | **3,178** | **165** | **437** | **346** |
| 52 | | | | | | | | | | | | | | | | | |
| 53 | | 368 | **Line Transformers** | | | | | | | | | | | | | | 1.2 |
| 54 | 13.780% | 368 | OH - Demand | NCP_P_ADJ | 35,544 | 18,945 | 222 | 732 | 8,254 | 33 | 22 | 17 | 5,195 | 1,943 | 17 | 89 | 74 |
| 55 | 17.147% | 368 | UG - Demand | NCP_P_ADJ | 44,230 | 23,575 | 276 | 911 | 10,271 | 41 | 27 | 22 | 6,464 | 2,418 | 21 | 111 | 92 |
| 56 | 64.487% | 368 | OH - Customer | Cust_368 | 166,339 | 140,913 | - | - | 24,027 | - | - | - | 337 | 16 | 0 | 631 | 414 |
| 57 | 4.59% | 368 | UG - Customer | Cust_368 | 11,828 | 10,020 | - | - | 1,709 | - | - | - | 24 | 1 | 0 | 45 | 29 |
| 58 | | | | | | | | | | | | | | | | | |
| 59 | | 368 | Capacitors | POWERF | 4,541 | 2,206 | - | - | 978 | - | - | - | 937 | 359 | 19 | 23 | 19 |
| 60 | | | **Total 368 (sum of lines 54 to 59)** | | **262,481** | **195,659** | **497** | **1,644** | **45,238** | **75** | **50** | **39** | **12,958** | **4,737** | **57** | **898** | **629** |
| 61 | | | | | | | | | | | | | | | | | |
| 62 | | 369 | Services - Customer | SERV_369 | 158,352 | 127,548 | - | - | 30,731 | - | - | - | - | - | - | 23 | 51 |
| 63 | | 370 | Meters - Customer | METER_370 | 90,764 | 60,816 | 565 | 5,452 | 21,365 | 139 | 31 | 161 | 2,042 | 166 | 27 | - | - |
| 64 | | 371 | Inst. On Cust. Premises - Cust | CUST_371 | 6,564 | - | - | - | - | - | - | - | - | - | - | 6,564 | - |
| 65 | | 373 | Street Lighting - Customer | ST_DIRECT | 5,131 | - | - | - | - | - | - | - | - | - | - | 5,131 | - |
| 67 | | | | | | | | | | | | | | | | | |
| 68 | | | **Total Distribution Gross Plant** | | **1,924,064** | **1,271,155** | **6,401** | **22,442** | **359,283** | **874** | **581** | **569** | **151,214** | **88,121** | **3,716** | **16,298** | **3,409** |
| 69 | | | | | | | | | | | | | | | | | |
| 70 | | | **GENERAL PLANT** | | | | | | | | | | | | | | |
| 71 | | | | | | | | | | | | | | | | | |
| 72 | | 389 | Land & Land Rights | O_LABOR | 4,834 | 3,185 | 17 | 72 | 893 | 2 | 1 | 2 | 374 | 198 | 9 | 49 | 31 |
| 73 | | 390 | Structures & Improvements | O_LABOR | 84,414 | 55,621 | 303 | 1,259 | 15,600 | 39 | 25 | 34 | 6,532 | 3,449 | 154 | 860 | 537 |
| 74 | | 391 | Office Furniture & Equipment | O_LABOR | 11,442 | 7,539 | 41 | 171 | 2,115 | 5 | 3 | 5 | 885 | 468 | 21 | 117 | 73 |
| 75 | | 392 | Transportation Equipment | O_LABOR | 44,177 | 29,109 | 159 | 659 | 8,164 | 20 | 13 | 18 | 3,419 | 1,805 | 80 | 450 | 281 |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 76 | 393 | Stores Equipment | O_LABOR | 3,258 | 2,147 | 12 | 49 | 602 | 2 | 1 | 1 | 252 | 133 | 6 | 33 | 21 |
| 77 | 394 | Tool, Shop & Garage Equipment | O_LABOR | 14,195 | 9,353 | 51 | 212 | 2,623 | 7 | 4 | 6 | 1,098 | 580 | 26 | 145 | 90 |
| 78 | 395 | Laboratory Equipment | O_LABOR | 2,073 | 1,366 | 7 | 31 | 383 | 1 | 1 | 1 | 160 | 85 | 4 | 21 | 13 |
| 79 | 396 | Power Operated Equipment | O_LABOR | 159 | 105 | 1 | 2 | 29 | 0 | 0 | 0 | 12 | 7 | 0 | 2 | 1 |
| 80 | 397 | Communication Equipment | O_LABOR | 28,189 | 18,574 | 101 | 420 | 5,209 | 13 | 8 | 12 | 2,181 | 1,152 | 51 | 287 | 179 |
| 81 | 398 | Miscellaneous Equipment | O_LABOR | 1,279 | 843 | 5 | 19 | 236 | 1 | 0 | 1 | 99 | 52 | 2 | 13 | 8 |
| 82 | | | | | | | | | | | | | | | | |
| 83 | | **Total General Gross Plant (sum of lines 72 to 81)** | | **194,021** | **127,842** | **697** | **2,894** | **35,855** | **89** | **57** | **79** | **15,014** | **7,928** | **353** | **1,976** | **1,235** |
| 84 | | | | | | | | | | | | | | | | |
| 85 | | **Total Gross Plant (Line 68 + Line 84)** | | **2,171,045** | **1,433,894** | **7,289** | **26,126** | **404,925** | **988** | **654** | **670** | **170,327** | **98,212** | **4,166** | **18,813** | **4,981** |
| 86 | | | | | | | | | | | | | | | | |
| 87 | Total plant balances are from Schedule EHC/TMD-37, Page 2 | | | | | | | | | | | | | | | |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 3-A. ACCUMULATED DEPRECIATION**
**Per Books Test Year 2018**
**(in thousands)**

| Line | Account | DESCRIPTION | ALLOCATOR | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | | |
| 11 | | **INTANGIBLE PLANT** | | | | | | | | | | | | | | |
| 12 | 303D | Intangible Plant | INTPLANT | 46,159 | 30,415 | 166 | 689 | 8,530 | 21 | 14 | 19 | 3,572 | 1,886 | 84 | 470 | 294 |
| 13 | | | | | | | | | | | | | | | | |
| 14 | | **DISTRIBUTION PLANT** | | | | | | | | | | | | | | |
| 15 | 360 | Land & Land Rights | | | | | | | | | | | | | | |
| 16 | 361 | Structures & Improvements | STRUCT_D | 6,382 | 3,077 | 36 | 76 | 1,355 | 4 | 4 | 2 | 1,115 | 678 | 22 | 7 | 6 |
| 17 | 362 | Station Equipment | DIS_STATION | 62,750 | 30,251 | 354 | 748 | 13,327 | 36 | 35 | 23 | 10,964 | 6,665 | 218 | 71 | 59 |
| 18 | 364 | Poles, Towers & Fixtures | POL_PLANT | 136,745 | 105,903 | 182 | 602 | 21,401 | 27 | 18 | 14 | 4,791 | 2,852 | 150 | 477 | 326 |
| 19 | 365 | OH Conductor & Devices | OH_LINE | 113,599 | 71,287 | 377 | 1,246 | 20,988 | 57 | 38 | 30 | 11,537 | 7,104 | 370 | 326 | 241 |
| 20 | 366 | UG Conduit | UG_LINE | 5,593 | 3,942 | 35 | 115 | 1,107 | 4 | 2 | 2 | 214 | 133 | 7 | 18 | 14 |
| 21 | 367 | UG Conductor & Devices | UG_LINE | 41,988 | 29,593 | 261 | 862 | 8,308 | 28 | 19 | 15 | 1,607 | 998 | 52 | 137 | 109 |
| 22 | 368 | Line Transformers | TRANSF_PLANT | 78,707 | 59,030 | 152 | 502 | 13,505 | 23 | 15 | 12 | 3,668 | 1,336 | 12 | 267 | 186 |
| 23 | 369 | Services | CUS_369 | 35,251 | 28,394 | - | - | 6,841 | - | - | - | - | - | - | 5 | 11 |
| 24 | 370 | Meters | MET_PLANT | 17,297 | 11,590 | 108 | 1,039 | 4,072 | 26 | 6 | 31 | 389 | 32 | 5 | - | - |
| 25 | 371 | Inst. On Cust. Premises | CUST_371 | 1,207 | - | - | - | - | - | - | - | - | - | - | 1,207 | - |
| 26 | 373 | Street Lighting | ST_DIRECT | 3,821 | - | - | - | - | - | - | - | - | - | - | 3,821 | - |
| 27 | | | | | | | | | | | | | | | | |
| 28 | | **Total Accu. Depr. Distribution Plant (sum of lines 15 to 26)** | | 503,340 | 343,065 | 1,504 | 5,189 | 90,904 | 204 | 136 | 128 | 34,285 | 19,797 | 836 | 6,337 | 953 |
| 29 | | | | | | | | | | | | | | | | |
| 30 | | **GENERAL PLANT** | | | | | | | | | | | | | | |
| 31 | 389 | Land & Land Rights | | | | | | | | | | | | | | |
| 32 | 390D | Structures & Improvements | GPLANT | 15,490 | 10,206.26 | 55.65 | 231.04 | 2,862.48 | 7.14 | 4.55 | 6.33 | 1,198.67 | 632.92 | 28.18 | 157.76 | 98.62 |
| 33 | 391D | Office Furniture & Equipemtn | GPLANT | 1,311 | 863.82 | 4.71 | 19.55 | 242.27 | 0.60 | 0.39 | 0.54 | 101.45 | 53.57 | 2.39 | 13.35 | 8.35 |
| 34 | 392D | Transportation Equipment | GPLANT | 23,271 | 15,333.49 | 83.60 | 347.11 | 4,300.48 | 10.73 | 6.84 | 9.51 | 1,800.84 | 950.88 | 42.34 | 237.01 | 148.17 |
| 35 | 393D | Stores Equipment | GPLANT | 723 | 476.58 | 2.60 | 10.79 | 133.66 | 0.33 | 0.21 | 0.30 | 55.97 | 29.55 | 1.32 | 7.37 | 4.61 |
| 36 | 394D | Tool, Shop & Garage Equipment | GPLANT | 3,214 | 2,117.79 | 11.55 | 47.94 | 593.96 | 1.48 | 0.95 | 1.31 | 248.72 | 131.33 | 5.85 | 32.73 | 20.46 |
| 37 | 395D | Laboratory Equipment | GPLANT | 329 | 216.68 | 1.18 | 4.91 | 60.77 | 0.15 | 0.10 | 0.13 | 25.45 | 13.44 | 0.60 | 3.35 | 2.09 |
| 38 | 396D | Power Operated Equipment | GPLANT | 104 | 68.26 | 0.37 | 1.55 | 19.14 | 0.05 | 0.03 | 0.04 | 8.02 | 4.23 | 0.19 | 1.06 | 0.66 |
| 39 | 397D | Communication Equipment | GPLANT | 7,992 | 5,265.87 | 28.71 | 119.21 | 1,476.88 | 3.68 | 2.35 | 3.27 | 618.45 | 326.55 | 14.54 | 81.39 | 50.88 |
| 40 | 398D | Miscellaneous Equipment | GPLANT | 494 | 325.57 | 1.78 | 7.37 | 91.31 | 0.23 | 0.15 | 0.20 | 38.24 | 20.19 | 0.90 | 5.03 | 3.15 |
| 41 | | | GPLANT | | | | | | | | | | | | | |
| 42 | | **Total Accu. Deprec. General Plant (sum of lines 31 to 40)** | | 52,927 | 34,874 | 190 | 789 | 9,781 | 24 | 16 | 22 | 4,096 | 2,163 | 96 | 539 | 337 |
| 43 | | | | | | | | | | | | | | | | |
| 44 | | **Total Accu. Depreciation (Line 12 + 28 + 42)** | | **602,426** | **408,354** | **1,860** | **6,667** | **109,215** | **250** | **166** | **169** | **41,953** | **23,845** | **1,016** | **7,346** | **1,584** |
| 45 | | | | | | | | | | | | | | | | |

46 Total plant balances are from Schedule EHC/TMD-38, Page 2

1 **Public Service Company of New Hampshire, d/b/a Eversource Energy**
2 **Allocated Embedded Cost of Service Study**
3 **TABLE 3-B. NET PLANT IN SERVICE**
4 **Per Books Test Year 2018**
5 **(in thousands)**

| 8 | Account | Description | Reference | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | **NET PLANT** | | | | | | | | | | | | | | |
| 12 | 301-303 | **Total Intangible Net Plant** | Table 2, Ln 14 - Table 3, Ln. 12 | 6,801 | 4,481 | 24 | 101 | 1,257 | 3 | 2 | 3 | 526 | 278 | 12 | 69 | 43 |
| 14 | | **DISTRIBUTION PLANT** | | | | | | | | | | | | | | |
| 15 | 360 | Land & Land Rights | Table 2, Ln 17 - Table 3, Ln 15 | 9,953 | 4,798 | 56 | 119 | 2,114 | 6 | 6 | 4 | 1,739 | 1,057 | 35 | 11 | 9 |
| 16 | 361 | Structures & Improvements | Table 2, Ln 18 - Table 3, Ln 16 | 20,006 | 9,644 | 113 | 238 | 4,249 | 11 | 11 | 7 | 3,495 | 2,125 | 69 | 23 | 19 |
| 17 | 362 | Station Equipment | Table 2, Ln 19 - Table 3, Ln 17 | 243,498 | 117,386 | 1,373 | 2,902 | 51,716 | 139 | 136 | 89 | 42,544 | 25,862 | 846 | 276 | 230 |
| 18 | 364 | Poles, Towers & Fixtures | Table 2, Ln 26 - Table 3, Ln 18 | 166,843 | 129,213 | 222 | 734 | 26,111 | 33 | 22 | 17 | 5,846 | 3,480 | 183 | 582 | 398 |
| 19 | 365 | OH Conductor & Devices | Table 2, Ln 33 - Table 3, Ln 19 | 468,497 | 293,995 | 1,555 | 5,139 | 86,557 | 233 | 155 | 122 | 47,581 | 29,296 | 1,526 | 1,345 | 993 |
| 20 | 366 | UG Conduit | Table 2, Ln 42 - Table 3, Ln 20 | 33,165 | 23,375 | 206 | 681 | 6,562 | 22 | 15 | 12 | 1,269 | 788 | 41 | 108 | 86 |
| 21 | 367 | UG Conductor & Devices | Table 2, Ln 51 - Table 3, Ln 21 | 91,754 | 64,669 | 570 | 1,884 | 18,154 | 62 | 41 | 32 | 3,512 | 2,180 | 113 | 300 | 237 |
| 22 | 368 | Line Transformers | Table 2, Ln 60 - Table 3, Ln 22 | 183,774 | 136,630 | 346 | 1,142 | 31,733 | 52 | 34 | 27 | 9,290 | 3,401 | 46 | 631 | 443 |
| 23 | 369 | Services | Table 2, Ln 62 - Table 3, Ln 23 | 123,101 | 99,154 | - | - | 23,890 | - | - | - | - | - | - | 18 | 40 |
| 24 | 370 | Meters | Table 2, Ln 63 - Table 3, Ln 24 | 73,467 | 49,226 | 458 | 4,413 | 17,294 | 112 | 25 | 130 | 1,653 | 134 | 22 | - | - |
| 25 | 371 | Inst. On Cust. Premises | Table 2, Ln 64 - Table 3, Ln 25 | 5,357 | - | - | - | - | - | - | - | - | - | - | 5,357 | - |
| 26 | 373 | Street Lighting | Table 2, Ln 65 - Table 3, Ln 26 | 1,310 | - | - | - | - | - | - | - | - | - | - | 1,310 | - |
| 28 | | **Total Distribution Net Plant** | Sum of Lines 15 to 26 | 1,420,725 | 928,090 | 4,898 | 17,253 | 268,379 | 670 | 445 | 441 | 116,929 | 68,324 | 2,880 | 9,960 | 2,456 |
| 30 | | **GENERAL PLANT** | | | | | | | | | | | | | | |
| 31 | 389 | Land & Land Rights | Table 2, Ln 72 - Table 3, Ln 31 | 4,834 | 3,185 | 17 | 72 | 893 | 2 | 1 | 2 | 374 | 198 | 9 | 49 | 31 |
| 33 | 390D | Structures & Improvements | Table 2, Ln 73 - Table 3, Ln 32 | 68,925 | 45,415 | 248 | 1,028 | 12,737 | 32 | 20 | 28 | 5,334 | 2,816 | 125 | 702 | 439 |
| 34 | 391D | Office Furniture & Equipment | Table 2, Ln 74 - Table 3, Ln 33 | 10,131 | 6,676 | 36 | 151 | 1,872 | 5 | 3 | 4 | 784 | 414 | 18 | 103 | 65 |
| 35 | 392D | Transportation Equipment | Table 2, Ln 75 - Table 3, Ln 34 | 20,906 | 13,775 | 75 | 312 | 3,863 | 10 | 6 | 9 | 1,618 | 854 | 38 | 213 | 133 |
| 36 | 393D | Stores Equipment | Table 2, Ln 76 - Table 3, Ln 35 | 2,535 | 1,670 | 9 | 38 | 468 | 1 | 1 | 1 | 196 | 104 | 5 | 26 | 16 |
| 37 | 394D | Tool, Shop & Garage Equipment | Table 2, Ln 77 - Table 3, Ln 36 | 10,981 | 7,235 | 39 | 164 | 2,029 | 5 | 3 | 4 | 850 | 449 | 20 | 112 | 70 |
| 38 | 395D | Laboratory Equipment | Table 2, Ln 78 - Table 3, Ln 37 | 1,744 | 1,149 | 6 | 26 | 322 | 1 | 1 | 1 | 135 | 71 | 3 | 18 | 11 |
| 39 | 396D | Power Operated Equipment | Table 2, Ln 79 - Table 3, Ln 38 | 56 | 37 | 0 | 1 | 10 | 0 | 0 | 0 | 4 | 2 | 0 | 1 | 0 |
| 40 | 397D | Communication Equipment | Table 2, Ln 80 - Table 3, Ln 39 | 20,197 | 13,308 | 73 | 301 | 3,732 | 9 | 6 | 8 | 1,563 | 825 | 37 | 206 | 129 |
| 41 | 398D | Miscellaneous Equipment | Table 2, Ln 81 - Table 3, Ln 40 | 785 | 517 | 3 | 12 | 145 | 0 | 0 | 0 | 61 | 32 | 1 | 8 | 5 |
| 43 | | **Total General Net Plant** | Sum of Lines 33 to 41 | 141,094 | 92,968 | 507 | 2,105 | 26,074 | 65 | 41 | 58 | 10,919 | 5,765 | 257 | 1,437 | 898 |
| 45 | | **Total Net Plant** | Line 12 + Line 28 + Line 43 | **1,568,619** | **1,025,539** | **5,429** | **19,459** | **295,710** | **738** | **488** | **501** | **128,374** | **74,367** | **3,150** | **11,467** | **3,397** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 4. RATE BASE**
**Per Books Test Year 2018**
**(in thousands)**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | RATE BASE | | | | | | | | | | | | | | | |
| 12 | | Utility Plant in Service | Table 2, Line 85 | | 2,171,045 | 1,433,894 | 7,289 | 26,126 | 404,925 | 988 | 654 | 670 | 170,327 | 98,212 | 4,166 | 18,813 | 4,981 |
| 14 | | Reserve For Depreciation | Table 3, Line 44 | | 602,426 | 408,354 | 1,860 | 6,667 | 109,215 | 250 | 166 | 169 | 41,953 | 23,845 | 1,016 | 7,346 | 1,584 |
| 16 | | **Net Plant** | Line 12 - Line 14 | | **1,568,619** | **1,025,539** | **5,429** | **19,459** | **295,710** | **738** | **488** | **501** | **128,374** | **74,367** | **3,150** | **11,467** | **3,397** |
| 18 | | DEDUCTIONS FROM PLANT | | | | | | | | | | | | | | | |
| 19 | | Reserve for Deferred Income Taxes | Sch. EHC/TMD-36 | NETPLANT | 365,772 | 239,136 | 1,266 | 4,537 | 68,954 | 172 | 114 | 117 | 29,934 | 17,341 | 734 | 2,674 | 792 |
| 21 | | Regulatory Liabilities | Sch. EHC/TMD-36 | NETPLANT | 4,037 | 2,639 | 14 | 50 | 761 | 2 | 1 | 1 | 330 | 191 | 8 | 30 | 9 |
| 22 | 235 | Customer Deposits/Advances | Sch. EHC/TMD-36 | CUST_235 | 8,401 | 3,858 | - | - | 4,257 | - | - | - | 183 | 96 | 8 | 0 | 0 |
| 24 | | **Total Deductions from Plant** | Sum of Lines 19 to 22 | | **378,209** | **245,633** | **1,280** | **4,587** | **73,972** | **174** | **115** | **118** | **30,447** | **17,628** | **750** | **2,703** | **801** |
| 26 | | ADDITIONS TO PLANT | | | | | | | | | | | | | | | |
| 27 | | Distribution Cash Working Capital | Sch. EHC/TMD-36 | OM_PT | 12,591 | 7,905 | 36 | 157 | 2,518 | 6 | 3 | 4 | 1,138 | 619 | 33 | 108 | 63 |
| 28 | | Materials and Supplies | Sch. EHC/TMD-36 | NETPLANT | 12,213 | 7,985 | 42 | 152 | 2,302 | 6 | 4 | 4 | 1,000 | 579 | 25 | 89 | 26 |
| 29 | | Prepayments | Sch. EHC/TMD-36 | NETPLANT | 729 | 476 | 3 | 9 | 137 | 0 | 0 | 0 | 60 | 35 | 1 | 5 | 2 |
| 30 | | Regulatory Assets | Sch. EHC/TMD-36 | NETPLANT | 3,423 | 2,238 | 12 | 42 | 645 | 2 | 1 | 1 | 280 | 162 | 7 | 25 | 7 |
| 32 | | **Total Additions** | Sum of Lines 27 to 30 | | **28,957** | **18,605** | **92** | **360** | **5,603** | **14** | **8** | **10** | **2,478** | **1,395** | **66** | **227** | **98** |
| 34 | | **TOTAL RATE BASE** | Line 16 - 24 + 32 | | **1,219,367** | **798,511** | **4,241** | **15,232** | **227,342** | **578** | **381** | **393** | **100,404** | **58,134** | **2,465** | **8,991** | **2,695** |
| 36 | | **COST OF CAPITAL** | Sch. EHC/TMD-3 | | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% | 7.08% |
| 38 | | **RETURN ON RATE BASE** | Line 34 x Line 36 | | **86,346** | **56,544** | **300** | **1,079** | **16,099** | **41** | **27** | **28** | **7,110** | **4,117** | **175** | **637** | **191** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 5. OPERATING REVENUES**
**Per Books Test Year 2018**
**(in thousands)**

| Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **OPERATING REVENUES** | | | | | | | | | | | | | | | |
| 440-446 | Distribution Sales Revenue | Att. EHC/TMD-4, p. 1 | DREV | 349,862 | 197,030 | 447 | 4,188 | 83,801 | 201 | 29 | 137 | 36,149 | 18,814 | 1,489 | 4,501 | 3,077 |
| | **OTHER OPERATING REVENUES** | | | | | | | | | | | | | | | |
| 447 | Resales Revenue | Att. EHC/TMD-4, p. 1 | DPLANT_P | 4,931 | 3,001 | 18 | 49 | 930 | 2 | 2 | 1 | 554 | 338 | 15 | 12 | 9 |
| 450 | Late Payment Charge | Att. EHC/TMD-4, p. 1 | LATE | 1,959 | 1,589 | - | - | 262 | - | - | - | 69 | 36 | - | 1 | 1 |
| 451 | Collection Charges | Att. EHC/TMD-4, p. 2 | 451_CC | 758 | 650 | - | - | 104 | - | - | - | 4 | - | - | - | - |
| 451 R14 | Reconnect-Reactivation Fees | Att. EHC/TMD-4, p. 2 | 451_RR | 2,314 | 2,128 | - | - | 180 | - | - | - | 5 | - | - | - | - |
| 451 R15 | Returned Check Fees | Att. EHC/TMD-4, p. 2 | 451_RC | 61 | 56 | - | - | 5 | - | - | - | 0 | - | - | - | - |
| 451 Misc | Other Misc. Service Revenues | Att. EHC/TMD-4, p. 2 | 451_Misc | (24) | (21) | - | - | (4) | - | - | - | (0) | - | - | - | - |
| 454 | Pole and Cable TV Rental | Att. EHC/TMD-4, p. 3 | POL_PLANT | 2,059 | 1,595 | 3 | 9 | 322 | 0 | 0 | 0 | 72 | 43 | 2 | 7 | 5 |
| 454 | Apparatus Rental Revenue | Att. EHC/TMD-4, p. 3 | TRANSF_454 | 3,365 | - | - | - | 8 | - | - | - | 2,648 | 700 | 9 | - | - |
| 454 | Other Rent from Electric Property | Att. EHC/TMD-4, p. 3 | OHPLANT | 285 | 193 | 1 | 2 | 50 | 0 | 0 | 0 | 22 | 14 | 1 | 1 | 1 |
| 456 | Other Electric Revenue | Att. EHC/TMD-4, p. 1 | DPLANT | 52 | 34 | 0 | 1 | 10 | 0 | 0 | 0 | 4 | 2 | 0 | 0 | 0 |
| | Total Other Revenues | Sum of Lines 15 to 24 | | **15,760** | **9,227** | **21** | **62** | **1,867** | **3** | **2** | **2** | **3,380** | **1,134** | **27** | **22** | **15** |
| | **TOTAL OPERATING REVENUE** | Line 12 + Line 26 | | **365,622** | **206,257** | **468** | **4,250** | **85,667** | **204** | **31** | **138** | **39,529** | **19,947** | **1,516** | **4,523** | **3,092** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 6. OPERATION AND MAINTENANCE EXPENSES**
**Per Books Test Year 2018**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | **OPERATING & MAINTENANCE EXPENSE** | | | | | | | | | | | | | | | |
| 12 | | **OPERATION** | | | | | | | | | | | | | | | |
| 13 | 555-557, 569 | Allocated Production and Transmission expenses | Att. EHC/TMD-5, p. 3 | DIS_STATION | 102 | 49 | 1 | 1 | 22 | 0 | 0 | 0 | 18 | 11 | 0 | 0 | 0 |
| 14 | 580 | Sup. & Eng. | Att. EHC/TMD-5, p. 3 | LABOR_D_O | 8,588 | 4,942 | 40 | 189 | 1,696 | 6 | 3 | 5 | 812 | 468 | 18 | 254 | 155 |
| 15 | 581 | Load Dispatching | Att. EHC/TMD-5, p. 3 | DIS_STATION | 902 | 435 | 5 | 11 | 192 | 1 | 1 | 0 | 158 | 96 | 3 | 1 | 1 |
| 16 | 582 | Station Expense | Att. EHC/TMD-5, p. 3 | DIS_STATION | 2,410 | 1,162 | 14 | 29 | 512 | 1 | 1 | 1 | 421 | 256 | 8 | 3 | 2 |
| 17 | 583 | Overhead Line Exp. | Att. EHC/TMD-5, p. 3 | OH_LINE | 2,879 | 1,807 | 10 | 32 | 532 | 1 | 1 | 1 | 292 | 180 | 9 | 8 | 6 |
| 18 | 584 | Underground Line Expenses | Att. EHC/TMD-5, p. 3 | UG_LINE | 1,782 | 1,256 | 11 | 37 | 353 | 1 | 1 | 1 | 68 | 42 | 2 | 6 | 5 |
| 19 | 585 | Street Lighting Exp. | Att. EHC/TMD-5, p. 3 | DIRECT ST | 486 | - | - | - | - | - | - | - | - | - | - | 297 | 189 |
| 20 | 586 | Meter Expense | Att. EHC/TMD-5, p. 3 | MET_PLANT | 2,265 | 1,518 | 14 | 136 | 533 | 3 | 1 | 4 | 51 | 4 | 1 | - | - |
| 21 | 587 | Customer Installation | Att. EHC/TMD-5, p. 3 | D_PLANT_587 | 6 | 4 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | 588 | Misc. Expense | Att. EHC/TMD-5, p. 3 | DPLANT | 2,501 | 1,653 | 8 | 29 | 467 | 1 | 1 | 1 | 197 | 115 | 5 | 21 | 4 |
| 23 | 589 | Rent, Other Expense (Pole rental) | Att. EHC/TMD-5, p. 3 | POL_PLANT | 1,085 | 841 | 1 | 5 | 170 | 0 | 0 | 0 | 38 | 23 | 1 | 4 | 3 |
| 25 | | Distribution Operation Expenses plus Allocated Transm. Expense (sum of lines 13 to 23) | | | 23,008 | 13,666 | 104 | 468 | 4,477 | 16 | 9 | 13 | 2,055 | 1,194 | 48 | 594 | 365 |
| 28 | | **MAINTENANCE** | | | | | | | | | | | | | | | |
| 29 | 590 | Sup. & Eng. | Att. EHC/TMD-5, p. 3 | LABOR_D_M | 163 | 101 | 1 | 2 | 31 | 0 | 0 | 0 | 16 | 10 | 0 | 1 | 1 |
| 30 | 591 | Structure | Att. EHC/TMD-5, p. 3 | DPLANT | 244 | 161 | 1 | 3 | 45 | 0 | 0 | 0 | 19 | 11 | 0 | 2 | 0 |
| 31 | 592 | Station Equipment | Att. EHC/TMD-5, p. 3 | DIS_STATION | 1,649 | 795 | 9 | 20 | 350 | 1 | 1 | 1 | 288 | 175 | 6 | 2 | 2 |
| 32 | 593 | OH Lines, Poles, Towers & Fixtures | Att. EHC/TMD-5, p. 3 | OH_LINE | 56,636 | 35,541 | 188 | 621 | 10,464 | 28 | 19 | 15 | 5,752 | 3,542 | 184 | 163 | 120 |
| 33 | 594 | Underground Line Expenses | Att. EHC/TMD-5, p. 3 | UG_LINE | 876 | 617 | 5 | 18 | 173 | 1 | 0 | 0 | 34 | 21 | 1 | 3 | 2 |
| 34 | 595 | Line Transformers | Att. EHC/TMD-5, p. 3 | TRANSF_PLANT | 828 | 621 | 2 | 5 | 142 | 0 | 0 | 0 | 39 | 14 | 0 | 3 | 2 |
| 35 | 596 | Street Lighting | Att. EHC/TMD-5, p. 3 | DIRECT ST | 48 | - | - | - | - | - | - | - | - | - | - | 30 | 19 |
| 36 | 597 | Meters | Att. EHC/TMD-5, p. 3 | MET_PLANT | 321 | 215 | 2 | 19 | 76 | 0 | 0 | 1 | 7 | 1 | 0 | - | - |
| 37 | 598 | Miscellaneous | Att. EHC/TMD-5, p. 3 | DPLANT | 14 | 9 | 0 | 0 | 3 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 |
| 39 | | Total Maintenance Expense | Sum of lines 29 to 37 | | 60,780 | 38,061 | 208 | 689 | 11,284 | 31 | 20 | 16 | 6,156 | 3,774 | 192 | 203 | 146 |
| 41 | | **TOTAL DISTRIBUTION O&M EXPENSES** | Line 25 + Line 39 | | **83,788** | **51,727** | **312** | **1,156** | **15,761** | **46** | **29** | **29** | **8,211** | **4,968** | **240** | **797** | **511** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 7. CUSTOMER ACCOUNT AND CUSTOMER SERVICE & INFORMATION EXPENSES**
**Per Books Test Year 2018**
**(in thousands)**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | CUSTOMER ACCOUNTS EXPENSES | | | | | | | | | | | | | | | |
| 12 | | CUSTOMER ACCOUNTS | | | | | | | | | | | | | | | |
| 13 | 901 | Supervision Expense | Att. EHC/TMD-5, p. 3 | CUST_ALL | 1 | 1 | - | - | 0 | - | - | - | 0 | 0 | 0 | 0 | 0 |
| 14 | 902 | Meter Reading Expense | Att. EHC/TMD-5, p. 3 | MTR_WF | 2,073 | 1,505 | 32 | 147 | 287 | 2 | 2 | 4 | 86 | 7 | 1 | - | - |
| 15 | 903 | Records & Collection Expense | Att. EHC/TMD-5, p. 3 | COLL903 | 15,058 | 11,872 | - | - | 2,682 | - | - | - | 465 | 38 | - | - | - |
| 16 | 904 | Uncollectible Account Exp. | Att. EHC/TMD-5, p. 3 | UNCOL904 | 2,441 | 2,285 | - | - | 141 | - | - | - | 2 | 1 | - | 7 | 5 |
| 17 | 905 | Miscellaneous Expense | Att. EHC/TMD-5, p. 3 | MIS_CUST XP | 88 | 71 | 0 | 1 | 14 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 |
| 19 | | Total Customer Accounts Exp. | Sum of Lines 13 to 17 | | 19,661 | 15,734 | 32 | 148 | 3,124 | 2 | 2 | 4 | 556 | 46 | 1 | 7 | 5 |
| 22 | | CUSTOMER SERVICE & INFORMATION | | | | | | | | | | | | | | | |
| 23 | 908 | Customer Assistance Expense | Att. EHC/TMD-5, p. 3 | CUS_908 | 267 | - | - | - | - | - | - | - | 247 | 20 | - | - | - |
| 24 | 910 | Miscellaneous CS & I Exp. | Att. EHC/TMD-5, p. 3 | CUS_908 | 10 | - | - | - | - | - | - | - | 9 | 1 | - | - | - |
| 26 | | Total Customer Service Exp. | Line 23 + Line 24 | | 277 | - | - | - | - | - | - | - | 256 | 21 | - | - | - |
| 29 | | SUPERVISION | | | | | | | | | | | | | | | |
| 30 | 911 | Supervision Expense | Att. EHC/TMD-5, p. 3 | CUST EXP_ALL | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 31 | 916 | Supervision & Misc. Expense | | CUST EXP_ALL | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | | Total Customer Edu/Adv. Exp. | Line 30 + Line 31 | | 2 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 35 | | **Total Customer Expense** | Line 19 + Line 26 + Line 33 | | **19,940** | **15,736** | **32** | **148** | **3,124** | **2** | **2** | **4** | **812** | **68** | **1** | **7** | **5** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 8. ADMINISTRATION AND GENERAL EXPENSES**
**Per Books Test Year 2018**
**(in thousands)**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | | ADMIN & GENERAL EXPENSES | | | | | | | | | | | | | | | |
| 13 | 920 | Salaries | Att. EHC/TMD-5, p. 3 | LABOR_D | 21,254 | 14,180 | 76 | 320 | 3,913 | 9 | 6 | 9 | 1,561 | 794 | 35 | 217 | 135 |
| 14 | 921 | Office Supplies Exp. | Att. EHC/TMD-5, p. 3 | DISTOMEXP | 4,085 | 2,569 | 15 | 57 | 783 | 2 | 1 | 1 | 408 | 247 | - | - | - |
| 15 | 922 | A & G Exp. Transferred Credits | Att. EHC/TMD-5, p. 3 | DISTOMEXP | (1,766) | (1,111) | (7) | (25) | (338) | (1) | (1) | (1) | (176) | (107) | - | - | - |
| 16 | 923 | Outside Service Exp | Att. EHC/TMD-5, p. 3 | LABOR_D | 9,376 | 6,256 | 33 | 141 | 1,726 | 4 | 3 | 4 | 689 | 350 | 15 | 96 | 59 |
| 17 | 924 | Property Insurance, Distribution Line | Att. EHC/TMD-5, p. 3 | NPLANT_OH | 164 | 103 | 1 | 2 | 31 | 0 | 0 | 0 | 17 | 10 | 0 | 0 | 0 |
| 18 | 925 | Injuries & Damages | Att. EHC/TMD-5, p. 3 | LABOR_D | 2,286 | 1,525 | 8 | 34 | 421 | 1 | 1 | 1 | 168 | 85 | 4 | 23 | 15 |
| 19 | 926 | Employee Pension & Benefits | Att. EHC/TMD-5, p. 3 | LABOR_D | 13,165 | 8,783 | 47 | 198 | 2,423 | 6 | 4 | 6 | 967 | 492 | 21 | 134 | 84 |
| 20 | 928 | Commission Expense, State Regulatory | Att. EHC/TMD-5, p. 3 | DPLANT | 4,770 | 3,152 | 16 | 56 | 891 | 2 | 1 | 1 | 375 | 218 | 9 | 40 | 8 |
| 21 | 930 | Miscellaneous General Exp. | Att. EHC/TMD-5, p. 3 | DISTOMEXP | 4,574 | 2,877 | 17 | 64 | 877 | 3 | 2 | 2 | 457 | 276 | - | - | - |
| 22 | 931 | Rent | Att. EHC/TMD-5, p. 3 | DPLANT | 988 | 652 | 3 | 12 | 184 | 0 | 0 | 0 | 78 | 45 | 2 | 8 | 2 |
| 23 | 935 | Maintenance of General Plant | Att. EHC/TMD-5, p. 3 | GENPLANT | 177 | 117 | 1 | 3 | 33 | 0 | 0 | 0 | 14 | 7 | 0 | 2 | 1 |
| 26 | EXP_O&M_A&G | Total Admin. & Gen. Expense | Sum of Lines 13 to 23 | | **59,072** | **39,103** | **211** | **863** | **10,943** | **27** | **17** | **24** | **4,555** | **2,418** | **87** | **521** | **304** |
| 28 | **EXP_O&M** | **Total O&M Expense** | Table 6, ln. 41 + Table 7, ln. 35 + Line 26 | | **162,801** | **106,566** | **554** | **2,167** | **29,828** | **75** | **48** | **57** | **13,578** | **7,454** | **328** | **1,324** | **819** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 9. DEPRECIATION EXPENSE**
**Per Books Test Year 2018**
**(in thousands)**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | DEPRECIATION EXPENSE | | | | | | | | | | | | | | | |
| 12 | 303DEP | Intangible Plant in Service | Att. EHC/TMD-28, p. 2 | INTPLANT | 2,219 | 1,462 | 8 | 33 | 410 | 1 | 1 | 1 | 172 | 91 | 4 | 23 | 14 |
| 15 | | DISTRIBUTION PLANT | | | | | | | | | | | | | | | |
| 16 | 360DEP | Land & Land Rights | Att. EHC/TMD-28, p. 2 | LANDPLANT | 177 | 86 | 1 | 2 | 38 | 0 | 0 | 0 | 31 | 19 | 1 | 0 | 0 |
| 17 | 361DEP | Structures & Improvements | Att. EHC/TMD-28, p. 2 | STRPLANT | 392 | 189 | 2 | 5 | 83 | 0 | 0 | 0 | 68 | 42 | 1 | 0 | 0 |
| 18 | 362DEP | Station Equipment | Att. EHC/TMD-28, p. 2 | DIS_STATION | 6,305 | 3,039 | 36 | 75 | 1,339 | 4 | 4 | 2 | 1,102 | 670 | 22 | 7 | 6 |
| 19 | 362.10 | Station Equipment -EMS | Att. EHC/TMD-28, p. 2 | DIS_STATION | 117 | 57 | 1 | 1 | 25 | 0 | 0 | 0 | 20 | 12 | 0 | 0 | 0 |
| 20 | 364DEP | Poles, Towers & Fixtures | Att. EHC/TMD-28, p. 2 | POL_PLANT | 8,930 | 6,916 | 12 | 39 | 1,398 | 2 | 1 | 1 | 313 | 186 | 10 | 31 | 21 |
| 21 | 365DEP | OH Conductor & Devices | Att. EHC/TMD-28, p. 2 | OH_LINE | 13,890 | 8,716 | 46 | 152 | 2,566 | 7 | 5 | 4 | 1,411 | 869 | 45 | 40 | 29 |
| 22 | 366DEP | UG Conduit | Att. EHC/TMD-28, p. 2 | UG_LINE | 930 | 656 | 6 | 19 | 184 | 1 | 0 | 0 | 36 | 22 | 1 | 3 | 2 |
| 23 | 367DEP | UG Conductor & Devices | Att. EHC/TMD-28, p. 2 | UG_LINE | 3,134 | 2,209 | 19 | 64 | 620 | 2 | 1 | 1 | 120 | 74 | 4 | 10 | 8 |
| 24 | 368DEP | Line Transformers | Att. EHC/TMD-28, p. 2 | TRANSF_PLANT | 5,788 | 4,341 | 11 | 37 | 993 | 2 | 1 | 1 | 270 | 98 | 1 | 20 | 14 |
| 25 | 369DEP | Services - OH | Att. EHC/TMD-28, p. 2 | CUS_369 | 4,835 | 3,895 | - | - | 938 | - | - | - | - | - | - | 1 | 2 |
| 26 | 369DEP | Services - UG | Att. EHC/TMD-28, p. 2 | CUS_369 | 3,262 | 2,627 | - | - | 633 | - | - | - | - | - | - | 0 | 1 |
| 27 | 370DEP | Meters | Att. EHC/TMD-28, p. 2 | MET_PLANT | 4,404 | 2,951 | 27 | 265 | 1,037 | 7 | 1 | 8 | 99 | 8 | 1 | - | - |
| 28 | 371DEP | Inst. On Cust. Premises | Att. EHC/TMD-28, p. 2 | CUST_371 | 755 | - | - | - | - | - | - | - | - | - | - | 755 | - |
| 29 | 373DEP | Street Lighting | Att. EHC/TMD-28, p. 2 | ST_DIRECT | 83 | - | - | - | - | - | - | - | - | - | - | 83 | - |
| 31 | | **Total Dist. Plant Dep. Exp.** | Sum of lines 16 to 29 | | **53,002** | **35,681** | **161** | **660** | **9,854** | **24** | **14** | **17** | **3,469** | **2,000** | **87** | **951** | **84** |
| 33 | | GENERAL PLANT | | | | | | | | | | | | | | | |
| 34 | 389 | Land and Land rights | Att. EHC/TMD-28, p. 2 | GPLANT | 1 | 0.58 | 0.00 | 0.01 | 0.16 | 0.00 | 0.00 | 0.00 | 0.07 | 0.04 | 0.00 | 0.01 | 0.01 |
| 35 | 390DEP | Structures & Improvements | Att. EHC/TMD-28, p. 2 | GPLANT | 1,795 | 1,182.89 | 6.45 | 26.78 | 331.76 | 0.83 | 0.53 | 0.73 | 138.92 | 73.35 | 3.27 | 18.28 | 11.43 |
| 36 | 391DEP | Office Furniture & Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 1,438 | 947.33 | 5.17 | 21.45 | 265.69 | 0.66 | 0.42 | 0.59 | 111.26 | 58.75 | 2.62 | 14.64 | 9.15 |
| 37 | 393DEP | Stores Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 216 | 142.54 | 0.78 | 3.23 | 39.98 | 0.10 | 0.06 | 0.09 | 16.74 | 8.84 | 0.39 | 2.20 | 1.38 |
| 38 | 394DEP | Tool, Shop & Garage Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 660 | 434.79 | 2.37 | 9.84 | 121.94 | 0.30 | 0.19 | 0.27 | 51.06 | 26.96 | 1.20 | 6.72 | 4.20 |
| 39 | 395DEP | Laboratory Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 268 | 176.68 | 0.96 | 4.00 | 49.55 | 0.12 | 0.08 | 0.11 | 20.75 | 10.96 | 0.49 | 2.73 | 1.71 |
| 40 | 396DEP | Power Operated Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 5 | 3.50 | 0.02 | 0.08 | 0.98 | 0.00 | 0.00 | 0.00 | 0.41 | 0.22 | 0.01 | 0.05 | 0.03 |
| 41 | 397DEP | Communication Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 2,634 | 1,735.45 | 9.46 | 39.29 | 486.73 | 1.21 | 0.77 | 1.08 | 203.82 | 107.62 | 4.79 | 26.82 | 16.77 |
| 42 | 398DEP | Miscellaneous Equipment | Att. EHC/TMD-28, p. 2 | GPLANT | 86 | 56.94 | 0.31 | 1.29 | 15.97 | 0.04 | 0.03 | 0.04 | 6.69 | 3.53 | 0.16 | 0.88 | 0.55 |
| 44 | | **TotaL Gen. Plant Dep. Exp.** | Sum of lines 34 to 42 | | **7,104** | **4,681** | **26** | **106** | **1,313** | **3** | **2** | **3** | **550** | **290** | **13** | **72** | **45** |
| 47 | EXP_DEP | **Total Depreciation Expense** | Line 12 + Line 31 + Line 44 | | **62,325** | **41,824** | **195** | **799** | **11,577** | **28** | **17** | **21** | **4,191** | **2,381** | **103** | **1,046** | **144** |
| 49 | | AMORTIZATION | | | | | | | | | | | | | | | |
| 51 | 407 | Amortization of Regulatory Asset | | RBASE | 15,815 | 10,445 | 53 | 190 | 2,950 | 7 | 5 | 5 | 1,241 | 715 | 30 | 137 | 36 |
| 52 | | EESCO Depreciation / Amortization | | RBASE | 5,062 | 3,343 | 17 | 61 | 944 | 2 | 2 | 2 | 397 | 229 | 10 | 44 | 12 |
| 54 | | **Total Amortization Expense** | Line 51 + Line 52 | | **$ 20,877** | **$ 13,788** | **$ 70** | **$ 251** | **$ 3,894** | **$ 10** | **$ 6** | **$ 6** | **$ 1,638** | **$ 944** | **$ 40** | **$ 181** | **$ 48** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 10. PAYROLL TAXES AND OTHER NON-INCOME TAXES**
**Per Books Test Year 2018**
**(in thousands)**

| Line | Account | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | **PAYROLL RELATED TAXES** | | | | | | | | | | | | | | | |
| 11 | 408020 | FICA Tax | Att. EHC/TMD-5, p. 4 | O_LABOR | 5,854 | 3,857 | 21 | 87 | 1,082 | 3 | 2 | 2 | 453 | 239 | 11 | 60 | 37 |
| 12 | 408050 | Medicare Tax | Att. EHC/TMD-5, p. 4 | O_LABOR | 1,581 | 1,042 | 6 | 24 | 292 | 1 | 0 | 1 | 122 | 65 | 3 | 16 | 10 |
| 13 | 408010 | Federal Unemployment Tax | Att. EHC/TMD-5, p. 4 | O_LABOR | 38 | 25 | 0 | 1 | 7 | 0 | 0 | 0 | 3 | 2 | 0 | 0 | 0 |
| 15 | 408011 | Massachusetts | Att. EHC/TMD-5, p. 4 | O_LABOR | 48 | 32 | 0 | 1 | 9 | 0 | 0 | 0 | 4 | 2 | 0 | 0 | 0 |
| 16 | 408001 | Connecticut | Att. EHC/TMD-5, p. 4 | O_LABOR | 68 | 45 | 0 | 1 | 13 | 0 | 0 | 0 | 5 | 3 | 0 | 1 | 0 |
| 17 | 4081H0 | New Hampshire | Att. EHC/TMD-5, p. 4 | O_LABOR | 13 | 9 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 |
| 18 | 408360 | District of Columbia | Att. EHC/TMD-5, p. 4 | O_LABOR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | 408180 | Universal Health | Att. EHC/TMD-5, p. 4 | O_LABOR | 9 | 6 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| 20 | | Payroll Taxes Transferred-Credit | Att. EHC/TMD-32, p. 2 | O_LABOR | (3,590) | (2,366) | (13) | (54) | (663) | (2) | (1) | (1) | (278) | (147) | (7) | (37) | (23) |
| 21 | | **Net Payroll Taxes** | Sum of lines 11 to 20 | | **4,021** | **2,649** | **14** | **60** | **743** | **2** | **1** | **2** | **311** | **164** | **7** | **41** | **26** |
| 23 | 408.19 | **Property Tax** | Att. EHC/TMD-5, p. 4 | NETPLANT | **47,118** | **30,805** | **163** | **584** | **8,882** | **22** | **15** | **15** | **3,856** | **2,234** | **95** | **344** | **102** |
| 25 | 408140 | Federal Highway | Att. EHC/TMD-5, p. 4 | NETPLANT | 6 | 4 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | 408300 | Tangible Property | Att. EHC/TMD-5, p. 4 | NETPLANT | 13 | 9 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 |
| 27 | 408400 | New Hampshire Business Enterprise Tax | Att. EHC/TMD-5, p. 4 | NETPLANT | 657 | 429 | 2 | 8 | 124 | 0 | 0 | 0 | 54 | 31 | 1 | 5 | 1 |
| 28 | 408500 | New Hampshire Consumption Tax | Att. EHC/TMD-5, p. 4 | NETPLANT | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 29 | 408600 | Insurance Premium Excise | Att. EHC/TMD-5, p. 4 | NETPLANT | 49 | 32 | 0 | 1 | 9 | 0 | 0 | 0 | 4 | 2 | 0 | 0 | 0 |
| 31 | | **Total Other non-labor related taxes** | Sum of lines 25 to 29 | | **725** | **474** | **3** | **9** | **137** | **0** | **0** | **0** | **59** | **34** | **1** | **5** | **2** |
| 33 | | **TOTAL TAXES OTHER THAN INCOME TAX** | Line 21 + Line 23 + Line 31 | | **51,863** | **33,928** | **180** | **653** | **9,762** | **24** | **16** | **17** | **4,226** | **2,432** | **103** | **391** | **129** |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**TABLE 11. INCOME TAXES**
**Per Books Test Year 2018**
**(in thousands)**

| Line | Description | Reference | Allocator | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | **INCOME TAXES** | | | | | | | | | | | | | | | |
| 11 | Total Distribution Revenue | Table 5, Line 28 | | 365,622 | 206,257 | 468 | 4,250 | 85,667 | 204 | 31 | 138 | 39,529 | 19,947 | 1,516 | 4,523 | 3,092 |
| 13 | Total Expense excluding income taxes | Table 1B | | 297,866 | 196,106 | 999 | 3,871 | 55,060 | 137 | 87 | 102 | 23,634 | 13,212 | 575 | 2,942 | 1,140 |
| 15 | Book Net Income Before Interest and Income Taxes | Line 11 + Line 13 | | 67,757 | 10,151 | (531) | 379 | 30,607 | 67 | (56) | 36 | 15,896 | 6,735 | 940 | 1,581 | 1,952 |
| 17 | Interest on Long Term Debt | | RBASE | (22,286) | (14,719) | (75) | (268) | (4,157) | (10) | (7) | (7) | (1,748) | (1,008) | (43) | (193) | (51) |
| 19 | Operating Income after Interest on LTD | Line 15 + Line 16 | | 45,470 | (4,569) | (606) | 111 | 26,450 | 57 | (63) | 30 | 14,147 | 5,727 | 898 | 1,388 | 1,901 |
| 21 | Permanent & Flowthrough Temporary Differences: | | | | | | | | | | | | | | | |
| 22 | PERMANENT DIFF_Total Gross Plant | | RBASE | 298 | 197 | 1 | 4 | 56 | 0 | 0 | 0 | 23 | 13 | 1 | 3 | 1 |
| 23 | Provision for uncollectible accounts | | UNCOL904 | 5,255 | 4,920 | - | - | 303 | - | - | - | 5 | 3 | - | 14 | 10 |
| 24 | Disallowed meals expense | | LABOR_D | 39 | 26 | 0 | 1 | 7 | 0 | 0 | 0 | 3 | 1 | 0 | 0 | 0 |
| 26 | PERMANENT & FLOW THROUGH DIFF(410-411) | Sum of Lines 22 to 24 | | 5,592 | 5,143 | 1 | 4 | 365 | 0 | 0 | 0 | 31 | 18 | 1 | 17 | 11 |
| 28 | NORMALIZED TIMING DIFF_Dist Gross Plant | Line 32 - 29 - 30 | RBASE | (47,112) | (31,116) | (158) | (567) | (8,787) | (21) | (14) | (15) | (3,696) | (2,131) | (90) | (408) | (108) |
| 29 | NORMALIZED TIMING DIFF_Labor | | O_LABOR | 30,851 | 20,328 | 111 | 460 | 5,701 | 14 | 9 | 13 | 2,387 | 1,261 | 56 | 314 | 196 |
| 30 | NORMALIZED TIMING DIFF_Uncollectibles | | UNCOL904 | (29) | (27) | - | - | (2) | - | - | - | (0) | (0) | - | (0) | (0) |
| 32 | NORMALIZED DIFF(410-411) | Sum of Lines 28 to 30 | | (16,290) | (10,815) | (47) | (107) | (3,087) | (7) | (5) | (2) | (1,309) | (871) | (34) | (94) | 88 |
| 34 | Sub Total-adj to Taxable Income | Line 26 + Line 32 | | (10,698) | (5,672) | (46) | (103) | (2,722) | (7) | (5) | (2) | (1,277) | (853) | (34) | (77) | 99 |
| 36 | Depreciation not Applicable State Inc. Tax | | DPLANT | (23,940) | (15,816) | (80) | (279) | (4,470) | (11) | (7) | (7) | (1,881) | (1,096) | (46) | (203) | (42) |
| 38 | Taxable Income For State Income Taxes | Line 34 + Line 36 | | 10,832 | (26,057) | (732) | (271) | 19,258 | 39 | (75) | 21 | 10,988 | 3,778 | 818 | 1,109 | 1,957 |
| 40 | NH State Tax eff. Tax rate | | | 0.079 | 0.079 | 0.079 | 0.079 | 0.079 | 0.079 | 0.079 | 0.079 | 0.079 | 0.079 | 0.079 | 0.079 | 0.079 |
| 41 | NH Income State Tax | Line 38 x Line 40 | | 856 | (2,058) | (58) | (21) | 1,521 | 3 | (6) | 2 | 868 | 298 | 65 | 88 | 155 |
| 43 | Taxable Income-Federal Tax | Line 36 + Line 38 | | 34,773 | (10,240) | (652) | 8 | 23,728 | 50 | (68) | 28 | 12,870 | 4,874 | 864 | 1,311 | 2,000 |
| 44 | Federal Taxable Income | Line 43 - Line 41 | | 33,917 | (8,182) | (594) | 29 | 22,207 | 47 | (62) | 26 | 12,002 | 4,576 | 799 | 1,224 | 1,845 |
| 46 | Federal Income Tax @21% | Line 44 x 21% | | 7,123 | (1,718) | (125) | 6 | 4,663 | 10 | (13) | 5 | 2,520 | 961 | 168 | 257 | 387 |
| 48 | **Total Current Federal & State Income Taxes** | Line 41 + Line 46 | | **7,978** | **(3,777)** | **(183)** | **(15)** | **6,185** | **13** | **(19)** | **7** | **3,388** | **1,259** | **232** | **345** | **542** |
| 50 | **DEFERRED INCOME TAXES** | | | | | | | | | | | | | | | |
| 52 | Total Deferred Income Taxes | Att. EHC/TMD-34, p. 2 | NETPLANT | 6,030 | 3,943 | 21 | 75 | 1,137 | 3 | 2 | 2 | 494 | 286 | 12 | 44 | 13 |
| 53 | Investment Tax Credit Adjustment | Att. EHC/TMD-5, p. 2 | NETPLANT | (4) | (2) | (0) | (0) | (1) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 55 | **Deferred Inc Tax & Net ITC** | Line 52 + Line 53 | | **6,027** | **3,940** | **21** | **75** | **1,136** | **3** | **2** | **2** | **493** | **286** | **12** | **44** | **13** |

1 **Public Service Company of New Hampshire, d/b/a Eversource Energy**
2 **Allocated Embedded Cost of Service Study**
3 **TABLE 12. OPERATIONS AND MAINTENANCE EXPENSES - PAYROLL COMPONENT**
4 **Per Books Test Year 2018**
5 **(in thousands)**

| Line | Description | Reference | Pro Forma 12/31/2018 | Total Retail | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | **OPERATIONS** | | | | | | | | | | | | | | | |
| 11 | 556 System Control And Load Dispatching | Sch. EHC/TMD-14, W/P 1 | 56 | 51 | 25 | 0 | 1 | 11 | 0 | 0 | 0 | 9 | 5 | 0 | 0 | 0 |
| 12 | 580 Operation Supervision And Engineering | Sch. EHC/TMD-14, W/P 1 | 8,672 | 7,928 | 4,895 | 29 | 109 | 1,491 | 4 | 3 | 3 | 777 | 470 | 23 | 75 | 48 |
| 13 | 581 Load Dispatching | Sch. EHC/TMD-14, W/P 1 | 888 | 812 | 391 | 5 | 10 | 172 | 0 | 0 | 0 | 142 | 86 | 3 | 1 | 1 |
| 14 | 582 Station Expenses | Sch. EHC/TMD-14, W/P 1 | 2,052 | 1,876 | 904 | 11 | 22 | 398 | 1 | 1 | 1 | 328 | 199 | 7 | 2 | 2 |
| 15 | 583 Overhead Line Expenses | Sch. EHC/TMD-14, W/P 1 | 751 | 687 | 431 | 2 | 8 | 127 | 0 | 0 | 0 | 70 | 43 | 2 | 2 | 1 |
| 16 | 584 Underground Line Expenses | Sch. EHC/TMD-14, W/P 1 | 334 | 305 | 215 | 2 | 6 | 60 | 0 | 0 | 0 | 12 | 7 | 0 | 1 | 1 |
| 17 | 585 Street Lighting And Signal System Expenses | Sch. EHC/TMD-14, W/P 1 | 385 | 352 | - | - | - | - | - | - | - | - | - | - | 215 | 137 |
| 18 | 586 Meter Expenses | Sch. EHC/TMD-14, W/P 1 | 1,948 | 1,781 | 1,193 | 11 | 107 | 419 | 3 | 1 | 3 | 40 | 3 | 1 | - | - |
| 19 | 587 Customer Installations Expenses | Sch. EHC/TMD-14, W/P 1 | 5 | 5 | 3 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | 588 Miscellaneous Distribution Expenses | Sch. EHC/TMD-14, W/P 1 | 2,205 | 2,016 | 1,332 | 7 | 24 | 376 | 1 | 1 | 1 | 158 | 92 | 4 | 17 | 4 |
| 21 | 589 Distribution Operations Rent | Sch. EHC/TMD-14, W/P 1 | 231 | 211 | 163 | 0 | 1 | 33 | 0 | 0 | 0 | 7 | 4 | 0 | 1 | 1 |
| 23 | **MAINTENANCE** | | | | | | | | | | | | | | | |
| 24 | 590 Maintenance Supervising & Engineering | Sch. EHC/TMD-14, W/P 1 | 146 | 134 | 83 | 0 | 2 | 25 | 0 | 0 | 0 | 13 | 8 | 0 | 1 | 0 |
| 25 | 591 Maintenance Of Structures | Sch. EHC/TMD-14, W/P 1 | 144 | 131 | 87 | 0 | 2 | 25 | 0 | 0 | 0 | 10 | 6 | 0 | 1 | 0 |
| 26 | 592 Maintenance Of Station Equipment | Sch. EHC/TMD-14, W/P 1 | 1,133 | 1,035 | 499 | 6 | 12 | 220 | 1 | 1 | 0 | 181 | 110 | 4 | 1 | 1 |
| 27 | 593 Maintenance Of Overhead Lines | Sch. EHC/TMD-14, W/P 1 | 8,111 | 7,415 | 4,653 | 25 | 81 | 1,370 | 4 | 2 | 2 | 753 | 464 | 24 | 21 | 16 |
| 28 | 594 Maintenance Of Underground Lines | Sch. EHC/TMD-14, W/P 1 | 451 | 413 | 291 | 3 | 8 | 82 | 0 | 0 | 0 | 16 | 10 | 1 | 1 | 1 |
| 29 | 595 Maintenance Of Line Transformers | Sch. EHC/TMD-14, W/P 1 | 572 | 523 | 392 | 1 | 3 | 90 | 0 | 0 | 0 | 24 | 9 | 0 | 2 | 1 |
| 30 | 596 Maintenance Of Street Lighting And Signal Systems | Sch. EHC/TMD-14, W/P 1 | 45 | 41 | - | - | - | - | - | - | - | - | - | - | 25 | 16 |
| 31 | 597 Maintenance Of Meters | Sch. EHC/TMD-14, W/P 1 | 348 | 318 | 213 | 2 | 19 | 75 | 0 | 0 | 1 | 7 | 1 | 0 | - | - |
| 32 | 598 Maintenance Of Miscellaneous Distribution Plant | Sch. EHC/TMD-14, W/P 1 | 12 | 11 | 7 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| 33 | Operations & Maintenance Expenses - Subtotal | Sum of lines 11 to 32 | **28,487** | **26,044** | **15,778** | **104** | **415** | **4,978** | **15** | **9** | **11** | **2,549** | **1,519** | **69** | **367** | **230** |
| 35 | **Operations & Maintenance Expenses - Customer** | | | | | | | | | | | | | | | |
| 36 | 901 Supervision | Sch. EHC/TMD-14, W/P 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 37 | 902 Meter Reading Expenses | Sch. EHC/TMD-14, W/P 1 | 1,906 | 1,743 | 1,265 | 27 | 124 | 241 | 2 | 1 | 4 | 72 | 6 | 1 | - | - |
| 38 | 903 Customer Records And Collection Expenses | Sch. EHC/TMD-14, W/P 1 | 9,111 | 8,329 | 6,567 | - | - | 1,484 | - | - | - | 257 | 21 | - | - | - |
| 39 | 905 Customer Account Expenses | Sch. EHC/TMD-14, W/P 1 | 63 | 57 | 54 | - | - | 3 | - | - | - | 0 | 0 | - | 0 | 0 |
| 40 | 908 Customer Assistance Expenses | Sch. EHC/TMD-14, W/P 1 | 546 | 499 | 400 | 1 | 4 | 79 | 0 | 0 | 0 | 14 | 1 | 0 | 0 | 0 |
| 41 | Operations & Maintenance Expenses - Customer Subtotal | Sum of lines 36 to 40 | **11,625** | **10,628** | **8,286** | **28** | **127** | **1,808** | **2** | **2** | **4** | **343** | **28** | **1** | **0** | **0** |
| 43 | **Administrative and General Expenses** | | | | | | | | | | | | | | | |
| 44 | 920 Administrative & General Salaries | Sch. EHC/TMD-14, W/P 1 | 14,049 | 12,844 | 8,569 | 46 | 194 | 2,364 | 6 | 4 | 5 | 943 | 480 | 21 | 131 | 81 |
| 45 | 925 Injuries & Damages | Sch. EHC/TMD-14, W/P 1 | 220 | 201 | 134 | 1 | 3 | 37 | 0 | 0 | 0 | 15 | 8 | 0 | 2 | 1 |
| 46 | 926 Employee Pension & Benefits | Sch. EHC/TMD-14, W/P 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 47 | 928 Regulatory Commission Expense | Sch. EHC/TMD-14, W/P 1 | 4 | 4 | 3 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 48 | 935 Maintenance of General Plant | Sch. EHC/TMD-14, W/P 1 | 111 | 102 | 67 | 0 | 2 | 19 | 0 | 0 | 0 | 8 | 4 | 0 | 1 | 1 |
| 49 | Operations & Maintenance Expenses - A&G Subtotal | Sum of lines 44 to 49 | **14,384** | **13,151** | **8,773** | **47** | **198** | **2,421** | **6** | **4** | **5** | **966** | **491** | **21** | **134** | **83** |
| 51 | **TOTAL PAYROLL EXPENSES** | Lines 33 + 41 + 49 | **54,497** | **49,823** | **32,837** | **179** | **741** | **9,206** | **23** | **15** | **20** | **3,858** | **2,038** | **91** | **502** | **314** |

1 **Public Service Company of New Hampshire, d/b/a Eversource Energy**
2 **Allocated Embedded Cost of Service Study**
3 **APPENDIX 1. EXTERNAL AND INTERNAL ALLOCATION FACTORS**
4 **Per Books Test Year 2018**

5 **As per Book Adjusted Test Year**
6 OPTION FILTER

| # | DESCRIPTION | ALLOCATOR | TOTAL SYSTEM | R PL+TOD | R LCS | RWH | GPL+TOD | G SH | G LCS | G-WH | GV | LG | <115 KV RATE B | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | | | | | | | | | | | | | | | **Page 17 of 20** |
| 10 | **CP Allocators** | | 1,667,794.71 | 814,292.07 | 9,522.23 | 8,719.78 | 356,475.26 | 496.95 | 936.50 | 486.96 | 297,653.15 | 176,942.02 | 2,269.80 | - | - |
| 11 | Station-CP related | 20CP | 100.00% | 48.82% | 0.57% | 0.52% | 21.37% | 0.03% | 0.06% | 0.03% | 17.85% | 10.61% | 0.14% | - | - |
| 12 | | | 1,796,073.58 | 865,856.18 | 10,125.21 | 21,408.05 | 381,462.76 | 1,024.60 | 1,002.14 | 656.87 | 313,806.18 | 190,758.87 | 6,237.84 | 2,037.37 | 1,697.51 |
| 13 | 53% Bulk stat; 43% Dis. | 20CP/NCP_P | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 14 | | | | | | | | | | | | | | | |
| 15 | **NCP Allocators** | | | | | | | | | | | | | | |
| 16 | | | 1,940,728.49 | 924,002.95 | 10,805.17 | 35,716.09 | 409,640.15 | 1,619.61 | 1,076.16 | 848.48 | 332,021.31 | 206,339.56 | 10,712.44 | 4,334.83 | 3,611.73 |
| 17 | Demand-non station | NCP_P | 100.00% | 47.61% | 0.56% | 1.84% | 21.11% | 0.08% | 0.06% | 0.04% | 17.11% | 10.63% | 0.55% | 0.22% | 0.19% |
| 18 | | | 1,733,553.03 | 924,002.95 | 10,805.17 | 35,716.09 | 402,553.37 | 1,619.61 | 1,076.16 | 848.48 | 253,364.96 | 94,786.18 | 833.50 | 4,334.83 | 3,611.73 |
| 19 | Company-owned Xfmr | NCP_P_ADJ | 100.00% | 53.30% | 0.62% | 2.06% | 23.22% | 0.09% | 0.06% | 0.05% | 14.62% | 5.47% | 0.05% | 0.25% | 0.21% |
| 20 | | | 1,258,655.13 | 924,002.95 | 10,805.17 | 35,716.09 | 277,880.59 | 1,052.75 | 699.51 | 551.51 | - | - | - | 4,334.83 | 3,611.73 |
| 21 | Single phase D plant | NCP_P_1ph | 100.00% | 73.41% | 0.86% | 2.84% | 22.08% | 0.08% | 0.06% | 0.04% | - | - | - | 0.34% | 0.29% |
| 22 | | NCP_S_1ph | 100.00% | 73.41% | 0.86% | 2.84% | 22.08% | 0.08% | 0.06% | 0.04% | 0.00% | 0.00% | 0.00% | 0.34% | 0.29% |
| 23 | | | 1,259,895.61 | 924,002.95 | 10,805.17 | 35,716.09 | 277,880.59 | 1,619.61 | 1,076.16 | 848.48 | - | - | - | 4,334.83 | 3,611.73 |
| 24 | Secondary plant | NCP_S | 100.00% | 73.34% | 0.86% | 2.83% | 22.06% | 0.13% | 0.09% | 0.07% | - | - | - | 0.34% | 0.29% |
| 30 | | | 535.00 | - | - | - | - | - | - | - | - | - | - | 535.00 | |
| 31 | Streetlighting | CUST_371 | 100.00% | - | - | - | - | - | - | - | - | - | - | 100.00% | |
| 32 | Streetlighting | ST_DIRECT | 1.00 | - | - | - | - | - | - | - | - | - | - | 1.00 | - |
| 33 | Meter cost allocator | METER_370 | 100.00% | 67.00% | 0.62% | 6.01% | 23.54% | 0.15% | 0.03% | 0.18% | 2.25% | 0.18% | 0.03% | - | - |
| 34 | Meter plant weight | MTR_WF | 100.00% | 72.62% | 1.55% | 7.09% | 13.85% | 0.09% | 0.08% | 0.21% | 4.14% | 0.32% | 0.05% | - | - |
| 35 | | | | | | | | | | | | | | | |
| 36 | **Customer Allocators** | | | | | | | | | | | | | | |
| 37 | | | 519,578.20 | 440,810.80 | - | - | 76,487.00 | - | - | - | 1,383.40 | 106.00 | 18.00 | 535.00 | 238.00 |
| 38 | Customer-related | CUST_ALL | 100.00% | 84.84% | - | - | 14.72% | - | - | - | 0.27% | 0.02% | 0.00% | 0.10% | 0.05% |
| 39 | | | (6,372,372.00) | (2,926,586.00) | - | - | (3,228,828.00) | - | - | - | (138,474.73) | (72,669.26) | (5,798.00) | (9.32) | (6.68) |
| 40 | Customer deposit | CUST_235 | 100.00% | 45.93% | - | - | 50.67% | - | - | - | 2.17% | 1.14% | 0.09% | 0.00% | 0.00% |
| 41 | | | 547,273.26 | 440,810.80 | - | - | 106,206.69 | - | - | - | - | - | - | 77.91 | 177.87 |
| 42 | Services | SERV_369 | 100.00% | 80.55% | - | - | 19.41% | - | - | - | - | - | - | 0.01% | 0.03% |
| 43 | | | 522,073.99 | 440,810.80 | - | - | 76,487.00 | - | - | - | 1,383.40 | 106.00 | 18.00 | 1,973.03 | 1,295.76 |
| 44 | Customers | CUST_D | 100.00% | 84.43% | - | - | 14.65% | - | - | - | 0.26% | 0.02% | 0.00% | 0.38% | 0.25% |
| 45 | | | 500,667.92 | 440,810.80 | - | - | 56,588.33 | - | - | - | - | - | - | 1,973.03 | 1,295.76 |
| 46 | Single-phase cust | CUST_D_1ph | 100.00% | 88.04% | - | - | 11.30% | - | - | - | - | - | - | 0.39% | 0.26% |
| 47 | | | 520,349.13 | 440,810.80 | - | - | 75,163.77 | - | - | - | 1,055.67 | 48.69 | 1.40 | 1,973.03 | 1,295.76 |
| 48 | Transformer-customer | CUST_368 | 100.00% | 84.71% | - | - | 14.44% | - | - | - | 0.20% | 0.01% | 0.00% | 0.38% | 0.25% |
| 49 | | | 500,667.92 | 440,810.80 | - | - | 56,588.33 | - | - | - | - | - | - | 1,973.03 | 1,295.76 |
| 50 | Secondary customer | CUST_S | 100.00% | 88.04% | - | - | 11.30% | - | - | - | - | - | - | 0.39% | 0.26% |
| 51 | | | 50,269.88 | - | - | - | - | - | - | - | 46,430.47 | 3,839.41 | | | |
| 52 | Account 908 | CUS_908 | 100.00% | - | - | - | - | - | - | - | 92.36% | 7.64% | - | - | - |
| 53 | | | - | - | - | - | - | - | - | - | - | - | - | | |
| 54 | Uncollectible | UNCOL904 | 100.00% | 93.63% | - | - | 5.76% | - | - | - | 0.10% | 0.05% | - | 0.28% | 0.19% |
| 55 | | | | | | | | | | | | | | | |
| 56 | Account 903 | COLL903 | 100.00% | 78.85% | - | - | 17.81% | - | - | - | 3.09% | 0.26% | - | - | - |
| 57 | | | 7,889,479,674 | 3,144,970,835 | 36,776,884 | 92,916,119 | 1,716,678,138 | 5,451,861 | 4,509,879 | 3,379,300 | 1,665,675,827 | 1,172,438,767 | 18,134,625 | 17,231,142 | 11,316,297 |
| 58 | Sales kWh | ENERGY | 100.00% | 39.86% | 0.47% | 1.18% | 21.76% | 0.07% | 0.06% | 0.04% | 21.11% | 14.86% | 0.23% | 0.22% | 0.14% |
| 7 | | | | | | | | | | | | | | | **Page 18 of 20** |
| 8 | **Revenue Allocators** | | | | | | | | | | | | | | |
| 9 | | | 350,464,781 | 197,369,537 | 447,452 | 4,195,321 | 83,944,995 | 201,725 | 28,868 | 136,748 | 36,211,761 | 18,846,284 | 1,491,300 | 4,508,952 | 3,081,838 |
| 10 | Dist. Revenue | DREV | 100.00% | 56.32% | 0.13% | 1.20% | 23.95% | 0.06% | 0.01% | 0.04% | 10.33% | 5.38% | 0.43% | 1.29% | 0.88% |
| 11 | Revenue from Xfrm | TRANSF_454 | 100.00% | - | - | - | 0.24% | - | - | - | 78.69% | 20.80% | 0.27% | - | - |
| 12 | 451 Revenue | 451_Misc | 100.00% | 85.01% | - | - | 14.72% | - | - | - | 0.28% | - | - | - | - |
| 13 | 452 Revenue | 451_CC | 100.00% | 85.77% | - | - | 13.68% | - | - | - | 0.55% | - | - | - | - |
| 14 | 453 Revenue | 451_RR | 100.00% | 92.00% | - | - | 7.77% | - | - | - | 0.23% | - | - | - | - |
| 15 | 454 Revenue | 451_RC | 100.00% | 91.25% | - | - | 8.31% | - | - | - | 0.44% | - | - | - | - |
| 16 | Other revenue 451 | CUST_451 | 100.00% | 90.52% | - | - | 9.17% | - | - | - | 0.29% | 0.02% | 0.00% | 0.00% | - |
| 17 | | | | | | | | | | | | | | | |
| 18 | **INTERNAL ALLOCATORS** | | | | | | | | | | | | | | |
| 19 | **Operation & Maintenance Allocators** | | | | | | | | | | | | | | |
| 20 | | OM_581 | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 21 | | OM_582 | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 22 | | OM_583 | 100.00% | 62.75% | 0.33% | 1.10% | 18.48% | 0.05% | 0.03% | 0.03% | 10.16% | 6.25% | 0.33% | 0.29% | 0.21% |
| 23 | | OM_584 | 100.00% | 70.48% | 0.62% | 2.05% | 19.79% | 0.07% | 0.04% | 0.04% | 3.83% | 2.38% | 0.12% | 0.33% | 0.26% |
| 24 | | OM_585 | 100.00% | - | - | - | - | - | - | - | - | - | - | 61.08% | 38.92% |
| 25 | | OM_586 | 100.00% | 67.00% | 0.62% | 6.01% | 23.54% | 0.15% | 0.03% | 0.18% | 2.25% | 0.18% | 0.03% | - | - |
| 26 | | OM_587 | 100.00% | 72.22% | 0.22% | 2.09% | 19.97% | 0.05% | 0.01% | 0.06% | 0.78% | 0.06% | 0.01% | 4.49% | 0.02% |
| 27 | | OM_588 | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| 28 | | OM_589 | 100.00% | 77.45% | 0.13% | 0.44% | 15.65% | 0.02% | 0.01% | 0.01% | 3.50% | 2.09% | 0.11% | 0.35% | 0.24% |
| 29 | | OM_590 | 100.00% | 62.12% | 0.37% | 1.28% | 18.84% | 0.05% | 0.04% | 0.03% | 10.04% | 6.06% | 0.29% | 0.52% | 0.36% |
| 30 | | OM_591 | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| 31 | | OM_592 | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 32 | | OM_593 | 100.00% | 62.75% | 0.33% | 1.10% | 18.48% | 0.05% | 0.03% | 0.03% | 10.16% | 6.25% | 0.33% | 0.29% | 0.21% |
| 33 | | OM_594 | 100.00% | 70.48% | 0.62% | 2.05% | 19.79% | 0.07% | 0.04% | 0.04% | 3.83% | 2.38% | 0.12% | 0.33% | 0.26% |
| 34 | | OM_595 | 100.00% | 75.00% | 0.19% | 0.64% | 17.16% | 0.03% | 0.02% | 0.02% | 4.66% | 1.70% | 0.02% | 0.34% | 0.24% |
| 35 | | OM_596 | 100.00% | - | - | - | - | - | - | - | - | - | - | 61.08% | 38.92% |
| 36 | | OM_597 | 100.00% | 67.00% | 0.62% | 6.01% | 23.54% | 0.15% | 0.03% | 0.18% | 2.25% | 0.18% | 0.03% | - | - |

**Public Service Company of New Hampshire, d/b/a Eversource Energy**
**Allocated Embedded Cost of Service Study**
**APPENDIX 1. EXTERNAL AND INTERNAL ALLOCATION FACTORS**
**Per Books Test Year 2018**

**As per Book Adjusted Test Year**
OPTION FILTER

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OM_598 | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| OM_901 | 100.00% | 77.96% | 0.26% | 1.20% | 17.01% | 0.02% | 0.01% | 0.04% | 3.23% | 0.26% | 0.01% | 0.00% | 0.00% |
| OM_902 | 100.00% | 72.62% | 1.55% | 7.09% | 13.85% | 0.09% | 0.08% | 0.21% | 4.14% | 0.32% | 0.05% | - | - |
| OM_903 | 100.00% | 78.85% | - | - | 17.81% | - | - | - | 3.09% | 0.26% | - | - | - |
| OM_905 | 100.00% | 93.63% | - | - | 5.76% | - | - | - | 0.10% | 0.05% | - | 0.28% | 0.19% |
| OM_908 | 100.00% | 80.03% | 0.16% | 0.75% | 15.89% | 0.01% | 0.01% | 0.02% | 2.83% | 0.24% | 0.01% | 0.03% | 0.02% |
| OM_ALL | 100.00% | 61.74% | 0.37% | 1.38% | 18.81% | 0.06% | 0.03% | 0.04% | 9.80% | 5.93% | 0.29% | 0.95% | 0.61% |
| | 24,900.33 | 15,633.73 | 70.49 | 311.17 | 4,979.49 | 12.29 | 6.01 | 8.67 | 2,251.23 | 1,224.76 | 65.78 | 212.86 | 123.85 |
| OM_PT | 100.00% | 62.79% | 0.28% | 1.25% | 20.00% | 0.05% | 0.02% | 0.03% | 9.04% | 4.92% | 0.26% | 0.85% | 0.50% |
| OM_PT property tax | 13,538.63 | 8,851.348 | 46.856 | 167.946 | 2,552.251 | 6.373 | 4.213 | 4.326 | 1,107.985 | 641.856 | 27.183 | 98.968 | 29.323 |
| % of PM_PT-payroll taxe | 522.69 | 344.406 | 1.878 | 7.796 | 96.593 | 0.241 | 0.154 | 0.214 | 40.449 | 21.358 | 0.951 | 5.323 | 3.328 |
| % of total PM_PT-taxes | | 56.62% | 66.47% | 53.97% | 51.26% | 51.87% | 70.05% | 49.92% | 49.22% | 52.41% | 41.32% | 46.49% | 23.68% |
| % of total PM_PT- payroll taxes | | 2.20% | 2.66% | 2.51% | 1.94% | 1.96% | 2.56% | 2.46% | 1.80% | 1.74% | 1.45% | 2.50% | 2.69% |
| % of total PM_PT-O&M | | 41.18% | 30.86% | 43.52% | 46.80% | 46.17% | 27.40% | 47.62% | 48.99% | 45.85% | 57.23% | 51.01% | 73.64% |

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**Other Internal Allocators**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LATE | 100.00% | 81.12% | - | - | 13.38% | - | - | - | 3.55% | 1.85% | - | 0.06% | 0.04% |
| | 919,161.71 | 446,587.11 | | | 197,986.41 | | | | 189,709.30 | 72,609.32 | 3,769.54 | 4,636.55 | 3,863.49 |
| POWERF | 100.00% | 48.59% | - | - | 21.54% | - | - | - | 20.64% | 7.90% | 0.41% | 0.50% | 0.42% |
| | 306,248.38 | 147,637.08 | 1,726.45 | 3,650.28 | 65,043.19 | 174.70 | 170.87 | 112.00 | 53,507.07 | 32,526.28 | 1,063.61 | 347.39 | 289.44 |
| DIS_STATION | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| | 1,023,762.60 | 638,282.03 | 4,038.36 | 11,579.24 | 193,348.93 | 500.43 | 379.66 | 279.78 | 104,247.09 | 63,731.34 | 2,778.03 | 2,634.26 | 1,963.47 |
| NPLANT_OH | 100.00% | 62.35% | 0.39% | 1.13% | 18.89% | 0.05% | 0.04% | 0.03% | 10.18% | 6.23% | 0.27% | 0.26% | 0.19% |
| RBASE | 100.00% | 66.05% | 0.34% | 1.20% | 18.65% | 0.05% | 0.03% | 0.03% | 7.85% | 4.52% | 0.19% | 0.87% | 0.23% |
| | 582,095.62 | 365,281.80 | 1,931.86 | 6,385.68 | 107,544.87 | 289.57 | 192.41 | 151.70 | 59,117.83 | 36,400.08 | 1,895.40 | 1,670.56 | 1,233.87 |
| OH_LINE | 100.00% | 62.75% | 0.33% | 1.10% | 18.48% | 0.05% | 0.03% | 0.03% | 10.16% | 6.25% | 0.33% | 0.29% | 0.21% |
| | 172,499.49 | 121,578.09 | 1,071.38 | 3,541.42 | 34,130.44 | 115.64 | 76.84 | 60.58 | 6,602.94 | 4,099.17 | 212.89 | 563.91 | 446.18 |
| UG_LINE | 100.00% | 70.48% | 0.62% | 2.05% | 19.79% | 0.07% | 0.04% | 0.04% | 3.83% | 2.38% | 0.12% | 0.33% | 0.26% |
| DIRECT ST | - | - | - | - | - | - | - | - | - | - | - | 61.08% | 38.92% |
| | 90,764.20 | 60,815.87 | 565.26 | 5,451.64 | 21,365.37 | 138.72 | 30.85 | 160.93 | 2,042.16 | 165.94 | 27.47 | - | - |
| MET_PLANT | 100.00% | 67.00% | 0.62% | 6.01% | 23.54% | 0.15% | 0.03% | 0.18% | 2.25% | 0.18% | 0.03% | - | - |
| | 260,810.97 | 188,363.61 | 565.26 | 5,451.64 | 52,096.07 | 138.72 | 30.85 | 160.93 | 2,042.16 | 165.94 | 27.47 | 11,716.86 | 51.47 |
| D_PLANT_587 | 100.00% | 72.22% | 0.22% | 2.09% | 19.97% | 0.05% | 0.01% | 0.06% | 0.78% | 0.06% | 0.01% | 4.49% | 0.02% |
| | 303,587.83 | 235,116.11 | 404.26 | 1,336.25 | 47,511.48 | 60.59 | 40.26 | 31.74 | 10,637.18 | 6,332.15 | 333.36 | 1,059.81 | 724.63 |
| POL_PLANT | 100.00% | 77.45% | 0.13% | 0.44% | 15.65% | 0.02% | 0.01% | 0.01% | 3.50% | 2.09% | 0.11% | 0.35% | 0.24% |
| | 257,940.23 | 193,453.11 | 497.22 | 1,643.56 | 44,260.39 | 74.53 | 49.52 | 39.04 | 12,020.63 | 4,378.48 | 38.83 | 875.04 | 609.87 |
| TRANSF_PLANT | 100.00% | 75.00% | 0.19% | 0.64% | 17.16% | 0.03% | 0.02% | 0.02% | 4.66% | 1.70% | 0.02% | 0.34% | 0.24% |
| | 79,773.43 | 42,520.12 | 497.22 | 1,643.56 | 18,524.42 | 74.53 | 49.52 | 39.04 | 11,659.17 | 4,361.80 | 38.36 | 199.48 | 166.20 |
| TRANSF_PLANT_NCP | 100.00% | 53.30% | 0.62% | 2.06% | 23.22% | 0.09% | 0.06% | 0.05% | 14.62% | 5.47% | 0.05% | 0.25% | 0.21% |
| | 178,166.80 | 150,932.99 | - | - | 25,735.97 | - | - | - | 361.46 | 16.67 | 0.48 | 675.56 | 443.67 |
| TRANSF_PLANT_CUST | 100.00% | 84.71% | - | - | 14.44% | - | - | - | 0.20% | 0.01% | 0.00% | 0.38% | 0.25% |
| SHARE OF NCP | | 21.98% | | | 41.85% | 100.00% | | | 96.99% | 99.62% | 98.77% | 22.80% | 27.25% |
| | 1,924,064.47 | 1,271,155.45 | 6,401.30 | 22,442.00 | 359,282.90 | 874.49 | 581.03 | 569.29 | 151,214.46 | 88,120.55 | 3,716.40 | 16,297.71 | 3,408.90 |
| DPLANT | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| | 19,937.79 | 15,734.33 | 32.18 | 147.68 | 3,123.84 | 1.87 | 1.76 | 4.36 | 811.61 | 67.66 | 1.12 | 6.76 | 4.62 |
| CUST EXP_ALL | 100.00% | 78.92% | 0.16% | 0.74% | 15.67% | 0.01% | 0.01% | 0.02% | 4.07% | 0.34% | 0.01% | 0.03% | 0.02% |
| | 82,239.95 | 51,727.06 | 311.51 | 1,156.39 | 15,760.84 | 46.17 | 29.08 | 29.37 | 8,211.35 | 4,968.18 | - | - | - |
| DISTOMEXP | 100.00% | 62.90% | 0.38% | 1.41% | 19.16% | 0.06% | 0.04% | 0.04% | 9.98% | 6.04% | - | - | - |
| | 885,683.45 | 600,397.91 | 2,336.11 | 7,721.93 | 155,056.34 | 350.16 | 232.67 | 183.44 | 69,755.01 | 42,732.23 | 2,228.76 | 2,730.37 | 1,958.50 |
| OHPLANT | 100.00% | 67.79% | 0.26% | 0.87% | 17.51% | 0.04% | 0.03% | 0.02% | 7.88% | 4.82% | 0.25% | 0.31% | 0.22% |
| OHPLANT_ncp | | 199,772.42 | 2,336.11 | 7,721.93 | 87,310.14 | 350.16 | 232.67 | 183.44 | 68,620.64 | 42,645.32 | 2,214.00 | 937.20 | 780.87 |
| OHPLANT_CUST | | 400,625.49 | - | - | 67,746.20 | - | - | - | 1,134.37 | 86.92 | 14.76 | 1,793.17 | 1,177.64 |
| | 1,213,327.61 | 738,466.23 | 4,379.11 | 12,174.52 | 228,717.90 | 562.34 | 434.94 | 317.51 | 136,214.44 | 83,217.42 | 3,631.47 | 2,999.80 | 2,211.92 |
| DPLANT_P | 100.00% | 60.86% | 0.36% | 1.00% | 18.85% | 0.05% | 0.04% | 0.03% | 11.23% | 6.86% | 0.30% | 0.25% | 0.18% |
| | 342,589.41 | 165,156.46 | 1,931.32 | 4,083.45 | 72,761.55 | 195.44 | 191.15 | 125.29 | 59,856.50 | 36,386.02 | 1,189.83 | 388.61 | 323.79 |
| DPLANT_P_CP | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |

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**Other Internal Allocators**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 439,649.92 | 209,322.34 | 2,447.79 | 8,091.07 | 92,799.31 | 366.90 | 243.79 | 192.21 | 75,215.64 | 46,743.88 | 2,426.78 | 982.01 | 818.20 |
| DPLANT_P_NCP | 100.00% | 47.61% | 0.56% | 1.84% | 21.11% | 0.08% | 0.06% | 0.04% | 17.11% | 10.63% | 0.55% | 0.22% | 0.19% |
| | 431,088.29 | 363,987.44 | - | - | 63,157.04 | - | - | - | 1,142.30 | 87.53 | 14.86 | 1,629.18 | 1,069.94 |
| DPLANT_P_CUST | 100.00% | 84.43% | - | - | 14.65% | - | - | - | 0.26% | 0.02% | 0.00% | 0.38% | 0.25% |
| | 158,352.45 | 127,547.74 | - | - | 30,730.70 | - | - | - | - | - | - | 22.54 | 51.47 |
| CUS_369 | 100.00% | 80.55% | - | - | 19.41% | - | - | - | - | - | - | 0.01% | 0.03% |
| | 19,571.45 | 15,663.00 | 32.03 | 147.02 | 3,109.70 | 1.86 | 1.75 | 4.34 | 553.03 | 46.27 | 1.12 | 6.73 | 4.60 |
| MIS_CUST XP | 100.00% | 80.03% | 0.16% | 0.75% | 15.89% | 0.01% | 0.01% | 0.02% | 2.83% | 0.24% | 0.01% | 0.03% | 0.02% |
| NETPLANT | 100.00% | 65.38% | 0.35% | 1.24% | 18.85% | 0.05% | 0.03% | 0.03% | 8.18% | 4.74% | 0.20% | 0.73% | 0.22% |
| NETPLANT-CP | 100.00% | 48.63% | 0.56% | 1.17% | 21.19% | 0.06% | 0.06% | 0.04% | 17.30% | 10.47% | 0.34% | 0.11% | 0.09% |
| NETPLANT-NCP | 100.00% | 52.54% | 0.61% | 2.01% | 21.48% | 0.08% | 0.06% | 0.04% | 14.05% | 8.28% | 0.40% | 0.25% | 0.20% |
| NETPLANT-CUST | 100.00% | 80.81% | 0.08% | 0.75% | 16.13% | 0.02% | 0.00% | 0.02% | 0.55% | 0.04% | 0.01% | 1.31% | 0.27% |
| | 52,960.12 | 34,895.96 | 190.27 | 789.96 | 9,787.02 | 24.41 | 15.57 | 21.64 | 4,098.36 | 2,164.00 | 96.36 | 539.38 | 337.20 |

1 **Public Service Company of New Hampshire, d/b/a Eversource Energy**
2 **Allocated Embedded Cost of Service Study**
3 **APPENDIX 1. EXTERNAL AND INTERNAL ALLOCATION FACTORS**
4 **Per Books Test Year 2018**
5 **As per Book Adjusted Test Year**
6 OPTION FILTER

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25 | INTPLANT | 100.00% | 65.89% | 0.36% | 1.49% | 18.48% | 0.05% | 0.03% | 0.04% | 7.74% | 4.09% | 0.18% | 1.02% | 0.64% |
| 26 | | 9,953.05 | 4,798.20 | 56.11 | 118.63 | 2,113.90 | 5.68 | 5.55 | 3.64 | 1,738.98 | 1,057.10 | 34.57 | 11.29 | 9.41 |
| 27 | LANDPLANT | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 28 | | 26,387.98 | 12,721.19 | 148.76 | 314.53 | 5,604.46 | 15.05 | 14.72 | 9.65 | 4,610.45 | 2,802.64 | 91.65 | 29.93 | 24.94 |
| 29 | STRPLANT | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |
| 30 | | 194,020.81 | 127,842.27 | 697.05 | 2,894.03 | 35,855.02 | 89.43 | 57.05 | 79.28 | 15,014.43 | 7,927.88 | 353.02 | 1,976.03 | 1,235.33 |
| 31 | GENPLANT | 100.00% | 65.89% | 0.36% | 1.49% | 18.48% | 0.05% | 0.03% | 0.04% | 7.74% | 4.09% | 0.18% | 1.02% | 0.64% |
| 32 | AG_920 | 100.00% | 66.72% | 0.36% | 1.51% | 18.41% | 0.04% | 0.03% | 0.04% | 7.34% | 3.73% | 0.16% | 1.02% | 0.63% |
| 33 | AG_925 | 100.00% | 66.72% | 0.36% | 1.51% | 18.41% | 0.04% | 0.03% | 0.04% | 7.34% | 3.73% | 0.16% | 1.02% | 0.63% |
| 34 | AG_926 | 100.00% | 66.72% | 0.36% | 1.51% | 18.41% | 0.04% | 0.03% | 0.04% | 7.34% | 3.73% | 0.16% | 1.02% | 0.63% |
| 35 | AG_928 | 100.00% | 66.07% | 0.33% | 1.17% | 18.67% | 0.05% | 0.03% | 0.03% | 7.86% | 4.58% | 0.19% | 0.85% | 0.18% |
| 36 | AG_935 | 100.00% | 65.89% | 0.36% | 1.49% | 18.48% | 0.05% | 0.03% | 0.04% | 7.74% | 4.09% | 0.18% | 1.02% | 0.64% |
| 37 | LABOR_D | 100.00% | 66.72% | 0.36% | 1.51% | 18.41% | 0.04% | 0.03% | 0.04% | 7.34% | 3.73% | 0.16% | 1.02% | 0.63% |
| 38 | LABOR_D_O | 100.00% | 57.54% | 0.47% | 2.20% | 19.75% | 0.07% | 0.04% | 0.06% | 9.46% | 5.45% | 0.21% | 2.96% | 1.80% |
| 39 | LABOR_D_M | 100.00% | 62.12% | 0.37% | 1.28% | 18.84% | 0.05% | 0.04% | 0.03% | 10.04% | 6.06% | 0.29% | 0.52% | 0.36% |
| 40 | O_LABOR | 100.00% | 65.89% | 0.36% | 1.49% | 18.48% | 0.05% | 0.03% | 0.04% | 7.74% | 4.09% | 0.18% | 1.02% | 0.64% |
| 41 | | 26,387.98 | 12,721.19 | 148.76 | 314.53 | 5,604.46 | 15.05 | 14.72 | 9.65 | 4,610.45 | 2,802.64 | 91.65 | 29.93 | 24.94 |
| 42 | STRUCT_D | 100.00% | 48.21% | 0.56% | 1.19% | 21.24% | 0.06% | 0.06% | 0.04% | 17.47% | 10.62% | 0.35% | 0.11% | 0.09% |

**STATE OF NEW HAMPSHIRE**

**BEFORE THE**

**NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION**

**DOCKET NO. DE 19-057**

**REQUEST FOR PERMANENT RATES**

# DIRECT TESTIMONY OF

# AMPARO NIETO

***Marginal Cost of Distribution Service Study and Implications for Rate Design***

**On behalf of the Public Service Company of New Hampshire**

**d/b/a Eversource Energy**

**May 28, 2019**

Public Service Company of New Hampshire
d/b/a Eversource Energy
Docket No. DE 19-057
Testimony of Amparo Nieto
May 28, 2019

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## Attachment

Attachment MCOSS-1 - Marginal Cost of Service Study Report with Summary MCOSS Worksheets

**STATE OF NEW HAMPSHIRE**

**BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION**

**DIRECT TESTIMONY OF**
**AMPARO NIETO**

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

**May 28, 2019**

**Docket No. DE 19-057**

---

## I. INTRODUCTION

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

A. My name is Amparo Nieto. I am a Senior Vice President at Economists Incorporated ("EI"). My office is located at 101 Mission Street, San Francisco, California.

**Q. On whose behalf are you testifying in this rate case?**

A. I am testifying on behalf of Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH" or the "Company").

**Q. What is the purpose of your testimony?**

A. I recently completed an updated electricity marginal cost of distribution service study ("MCOSS") for PSNH. This testimony describes the method used, summarizes the results by rate class and discusses the main implications for evaluating the efficiency of existing PSNH's distribution rate design and potential revisions. The marginal cost results are useful to inform the direction of the changes that PSNH may adopt to improve existing distribution rates, both with regard to structure and price levels of specific components.

The MCOSS is also helpful to inform class revenue targets that would be consistent with marginal cost principles. The 2019 MCOSS results has been filed in this proceeding and are included in Attachment MCOSS-1.

**Q. Have you also provided separate testimony in this rate case on the Company's allocated cost of service study?**

A. Yes. I have also conducted an Allocated Cost of Service Study ("ACOSS") for the Company as required by the Commission and provided separate testimony on that topic. My ACOSS testimony includes further information on my professional background and qualifications.

**Q. How is your testimony organized?**

A. My testimony is organized as follows.

- In Section II, I summarize the findings of the MCOSS and the key implications for rate design.
- In Section III, I discuss why it is important to take into account marginal costs in distribution ratemaking.
- In Section IV, I discuss the specific marginal distribution cost methods that I employed to estimate PSNH's marginal costs.
- In Section V, I explain my review of class marginal distribution cost revenues, comparing them with the current rate revenues and ACOSS class revenue requirements and discuss the main findings from this comparison.

- In Section VI, I discuss the distribution rate structures that would more closely follow the marginal cost structure of the Company's distribution service, as well as the changes to specific rate components that would enable a more efficient use of the distribution system via more cost-reflective price signals.

- In Section VII, I provide conclusions on my review of PSNH's final rate designs.

## II. SUMMARY OF TESTIMONY

**Q. Please summarize the key findings and recommendations of your direct testimony regarding the marginal cost results.**

A. The MCOSS includes an estimate of all of the elements of marginal distribution costs of service by taking into account the specific characteristics of PSNH's distribution system and its customers. The marginal cost of electricity delivery represents the incremental cost incurred by the Company to serve the next unit of demand at any given point in time, voltage level and location. The incremental cost incurred by the Company to provide customer access to the grid as well as other customer-related services are also part of the marginal costs of distribution service. PSNH's MCOSS, as summarized in Attachment MCOSS-1, reveals that marginal upstream distribution costs are currently very low on a system-wide basis, given the relatively small amount of planned capacity expansion needed to meet station peak load growth over the study period 2020 through 2024. The peak load served by the identified substation projects represent only about 20 percent of the overall forecasted retail peak load in year 2024. This means that approximately 80 percent of the system will not require any upstream distribution capacity upgrades to reliably meet the expected peak load as per design requirements. The MCOSS also demonstrates that there are two different cost drivers for upstream distribution and the more local distribution facilities.

**Q. Please summarize the key findings and recommendations of your direct testimony regarding use of marginal cost results for revenue allocation.**

A. The Company's rates have been traditionally set on the basis of allocated cost of service studies. As I discuss in Section V of my testimony, a MCOSS-based revenue requirement allocation is more likely to lead to a welfare-maximizing pricing solution as compared to an ACOSS-based approach. The Company recognizes that there is a merit in using the findings of MCOSS in the rate design process, but it is proposing to continue relying on ACOSS as a reference for setting class revenue targets. Departing from the ACOSS method in the current rate case would result in major rebalancing among rate classes, further beyond the re-balancing already suggested by the 2019 ACOSS. In particular, the residential class would see a larger revenue target increase, which would be countered by significantly large reductions in revenue targets to other rate classes. These class revenue target shifts combined with a 19.98 percent increase in overall distribution revenue requirement would produce too large bill impacts. I find to be a reasonable concern. PSNH is not proposing any structural changes for its main rate classes in this proceeding, which would have enabled a smoother transition to a marginal cost-based revenue requirement approach. I recommend that the Company revisits a marginal cost-based revenue target approach at a later stage. In the meantime, it is still important to review the current marginal cost revenues by rate class and establish whether each class is paying at least marginal costs plus a share of the distribution sunk costs.

**Q. Please summarize the key findings of your direct testimony regarding use of marginal costs for rate design.**

A. This testimony describes what an efficient rate structure would look like if the Company were able to revise existing rates so that all customers could face a more efficient price signal, through the use of charges that more closely reflect the underlying distribution marginal costs. My main recommendations are summarized below.

- To follow cost causation, and given the low marginal distribution costs on a system-wide basis, it is essential to shift a share of the current recovery of distribution sunk costs away from the per-kWh or demand charges and towards customer charges for most customer classes.

- Introducing a monthly distribution facility charge on a per kW of customer maximum design (or connected) demand is useful to better align the cost driver of local facilities (transformers, local primary conductors and secondary voltage lines) to the method of recovery. This approach recognizes the more fixed nature of the transformers, which are sized based on the maximum demands that the local customers can be expected to impose over the service life of the facilities. These costs are more appropriately recovered using the customer's estimated design or contract demand as opposed to using actual metered demand or kilowatt-hours in a given month, to limit inter and intra-class subsidies.

- If introducing a contract demand or facilities charge is not feasible for a given rate class, I recommend recovering the marginal facilities cost estimated for the average customer as a monthly fixed charge, after appropriate consideration of bill impacts. The sum of monthly marginal customer and facilities cost should guide the required customer charge differential for one phase and three-phase customers within a given rate class.

- Ideally, all distribution rates would be seasonally differentiated, with a two-month summer season (July and August) to signal the months with the highest capacity constraints, or a four-month season (June through September) if switching to two-months would produce excessive bill impacts.

- Time-differentiation for distribution rates must keep in mind the system-wide distribution hourly marginal cost patterns. The current peak period should be shortened, and the peak/off-peak charge differential should be reduced.

**Q. Are PSNH'S proposed rate changes supported by the findings of the MCOSS?**

A. PSNH's distribution rate design proposals represent a conscious effort to moderate bill impacts resulting from the overall class revenue requirement increase, while still making an effort to adopt a number of measures that aim to improve the efficiency of rates, as informed by the MCOSS findings. The Company has increased the fixed charges of all customer classes as part of the overall revenue increase, to bring them closer to marginal customer cost in most cases, or to the sum of marginal customer and facilities costs, in the case of residential and commercial time-of-day rates. The Company also has ensured that the customer charges of the general service single phase and three phase customers are set to reflect the single-phase versus three-phase marginal customer and facilities cost relationship. A decision to modify the peak period in PSNH's existing Time of Day (TOD) distribution rates is pending given the Company's time of use pilot that the Company is planning to launch in the near term. Other factors such as introducing seasonality in rates will be addressed as more data by rate class is developed.

## III. DEFINITION OF MARGINAL COSTS AND THE THEORY SUPPORTING USE OF MARGINAL COST FOR UTILITY RATES

**Q. What is marginal cost?**

A. Marginal cost is the cost of the additional resources needed to produce and/or deliver the next small increment of output (or the costs avoided when consumers reduce their demand by a small amount). In perfectly competitive conditions, a market-clearing price is defined by the intersection of the total suppliers' marginal supply cost curve and the aggregated demand curve. In absence of market failures such as externalities, or economies of scale, the market clearing price will equal the social marginal cost of service. This outcome is economically efficient because it leads to a level of production (demand) that maximizes the sum of producer profits and the consumer surplus (the consumer's valuation of the product net of the price paid for it). In presence of natural monopolies such as regulated distribution utilities exhibiting large economies of scale, marginal cost continues to be important to signal the cost implications of increasing amounts of demand. Customers make decisions based on how the marginal increase in the bill compares to the value they obtain from the additional use of electricity.

**Q. What are the benefits of setting distribution rates that closely reflect the marginal grid costs?**

A. Aiming to achieve economic efficiency in the use of the distribution grid requires that the variable component of the delivery rates reflects as close as possible the marginal costs of providing service at any given time. If the price for additional usage of electricity reflects marginal costs, the utility will only plan for system upgrades to meet peak load growth when justified by the consumers' willingness to pay. In this scenario, the pattern and cycles of capacity expansion, and subsequently the cost of service, will be more aligned with how customers value reliable delivery of electricity. To maximize the efficiency gains from rate reforms, rates also need to inform the relative level of marginal cost differentials by time of day and/or season, and difference in marginal cost of service by voltage service. This is particularly important because it will lead customers to make decisions that align customer load reductions with system savings. Optimal utilization reduces unnecessary financial burden on the utility and ultimately on the rates paid by utility customers. It also reduces inter and intra-class cross subsidies.

**Q. How do marginal cost-based rates affect intra-class equity?**

A. If the variable rate is higher than the underlying marginal cost the quantity demanded will be too low as compared to the optimal level – additional electricity could have been served at a cost that would be lower than its value to the customer. Rate structure also needs to be aligned with marginal cost structure. If costs that do not vary with usage are recovered in a per-kWh charge, a high-load factor customer will pay more towards recovery of sunk costs, even though the customer may not impose higher costs than a lower load factor customer within the same class. The lack of time-differentiation or poorly designed periods may exacerbate this problem. A distortion also occurs in the case of prices that are set below the underlying marginal costs. In both cases there is a net deadweight loss that has both efficiency and equity implications.

**Q. Are marginal cost price signals important for efficient adoption of DERs by customers?**

A. Yes. Customers who face marginal cost-based price signals will decide to self-generate only when the cost of doing so is lower than the cost of having the utility delivering electricity to customer premises. Marginal cost-based rates are more likely to send economically efficient price signals as to when and where it is valuable for the system that the customer invests in energy storage along with rooftop solar or another form of distributed generation. Traditional net metering billing practices combined with simplified rate structures that often do not follow marginal cost structures are likely to produce the wrong incentives to adopt DERs. If the energy or demand charges are not marginal cost-based, in either regular or standby rates, customer-owned storage may be installed at a cost that exceeds the marginal cost of using the utility's resources. This outcome is not only inefficient but inequitable. Such inequity is exacerbated as self-supply alternatives available to consumers continue to grow, such as rooftop solar and other DER.

**Q. What is the right time framework to estimate marginal costs of distribution service?**

A. The marginal cost of securing delivery of power through the distribution grid for an additional kW at a given hour will vary depending on the amount of notice assumed, and the ability of the utility to respond to the change in usage. In the short run, these marginal costs involve mainly distribution losses and potentially shortage costs, if the transformer or grid does not have sufficient capacity to accommodate the new load. The value of the foregone electricity to the customer for whom the service has been interrupted represents the short-run marginal ("shortage") cost. This pure short-run marginal cost-scenario is not helpful to set utility rates, because the utility rates are set in advance for a number of years and, unless some forms of dynamic pricing, do not change in real-time conditions. For purposes of setting rates, the MCOSS needs to adopt a longer time framework for measuring marginal distribution costs, recognizing that the utility will plan the system as required in response to an anticipated unit of additional usage, which in some locations may involve capacity additions.

## IV. METHOD USED IN PSNH'S MCOSS

**Q. Please describe the main elements of the MCOSS that you prepared for PSNH.**

A. The MCOSS as filed by PSNH was a forward-looking exercise over a five-year horizon. This timeframe represents a good balance between the advance period that PSNH typically needs to formalize distribution investment plans (two to three years) and the timeframe needed to obtain a more stable price signal. The MCOSS covers the following elements of delivery service:

1. Marginal, time-related upstream delivery costs, including costs of bulk and non-bulk distribution stations, and trunk-line primary feeders that connect these substations to the more local primary lines. These are time-related costs as they are closely related to the growth in expected station peak loads. Only load increases

(or reductions) in hours coincident with the station peak hours have a bearing on the marginal costs of this component of service.

2. Local distribution facilities costs, including transformers and conductors local to the customer premises (primary and secondary). These elements of plant are not expanded with near term load fluctuations, but with additions of new customers and the long-term provision of service to the customer. When a new customer begins to receive service, marginal facilities cost is represented by the cost of installing enough transformer and local line capacity to accommodate the customer's expected long-term maximum demand.

3. Other components of distribution equipment are strictly customer-related, such as the cost of meters and service drops.

4. On-going marginal customer-related costs such as those required to administer and process meter reads and billing, and other services.

The annualized bulk station and non-bulk substation marginal costs are averaged across all the capacity-expansion areas and a system-wide average marginal cost is calculated for rate setting purposes. Marginal operation and maintenance ("O&M") expenses, and loading factors were included in the final annual cost. The MCOSS summarizes hourly marginal bulk and non-bulk distribution station costs by pricing periods suitable for the design of time of use ("TOU") and seasonal tariffs.

**Q. Please describe PSNH's primary distribution system.**

A. PSNH's primary voltage distribution system starts with bulk stations that are fed from the transmission system (115kV) and typically convert power to 34.5 kV or directly to 12 kV. Lower voltage distribution substations convert the load coming from the bulk station to either 12 kV or 4 kV; and trunk-line primary feeders connect the substation down to the primary tap lines. More than 80 percent of the total PSNH's retail load is served from small primary step transformers that convert the load directly coming from the bulk system to either 12.47 kV or 4.16 kV.

**Q. Please explain what criteria you used to select distribution station projects suitable for inclusion in the MCOSS.**

A. The marginal high-voltage distribution cost analysis builds upon a review of the Company's budgeted investments in both bulk and non-bulk substations during the upcoming planning period (2020-2024). The first step was to identify the relevant investments associated with planned bulk station upgrades or replacement projects. The criteria involved selection of projects that could potentially be avoided if the particular substation experienced peak load reductions. The majority of the distribution projects involve replacement of existing substation transformers with one (or two) larger transformers. They may intend to address overload conditions, and some may be driven by upcoming additions of industrial or commercial load, and/or by the need to offload nearby substations. PSNH's capital plan foresees station upgrade investments needed to ensure that peak load will be meet under both base case (N-0) and contingency scenarios (N-1). The Company's five-year capital plan includes upgrades for a portion of the bulk substations that are falling short of meeting the N-1 planning design criteria. N-0 projects inherently have a higher priority due to the need to have the capability to serve customer load under normal (base case) conditions.

**Q. What investments did you exclude from the marginal substation cost analysis**?

A. I excluded projected investments associated with retirement of obsolete equipment, since these are unlikely to be impacted by changes in the load. The MCOS study also excludes investments that are incurred to address asset condition, such as substandard design, old electromechanical relays, stations that need low-side voltage conversion, control house condition, or other reliability-related costs that are unrelated to growth in peak load.

**Q. What did your analysis of bulk station load forecasts on a system-wide basis reveal?**

**A.** I reviewed the Company's five-year forecast of bulk station peak load growth, which takes into account an assessment of both organic load growth and expected step load additions due to commercial and industrial activity. PSNH distribution planners decide the timing of expansion of a station under N-1 planning criteria when the station is loaded at or above 75 percent of its normal (nameplate) rating, since this level of load begins to compromise the station's long-term emergency rating. The emergency rating reflects the load that can be sustained temporarily, i.e., for a limited number of hours before voltage instability (or ultimately loss of load) occurs. Using the N-1 design criteria, I estimated the share of the bulk distribution system that is likely to require expansion as new load materializes using station peak forecast over the five-year period. The analysis reviewed that the majority of bulk stations will have ample capacity to serve peak demand during the study period.

**Q. How did you estimate the marginal non-bulk substation cost over the full five-year planning period?**

A. PSNH's capital plan includes an estimated amount of peak-load related investment in non-bulk distribution stations over the period 2020-2024, albeit it is not based on identified locations. The MCOSS relied on a forecast of non-bulk station peak loads over the next five years and compared them to the station long-term emergency ratings to identify potential investment needs at specific locations. These forecasts used the average regional peak load growth rates, rather than relying on station-specific projections since they were not available. PSNH, like many other US distribution utilities, predicts non-bulk station investments driven by peak load growth with sufficient confidence within a timeframe of two to three years. Projection of non-bulk expansion investments further into the future tend to be less certain than those at the higher voltage stations. Decisions about ultimately expanding a station transformer are not formalized until the station peak load begins to reach its long-term emergency rating. My review of these stations found that most of PSNH's non-bulk distribution system has more than sufficient capacity to meet expected peak load over the study period. The few capacity constraints that the MCOSS identified are largely expected to be addressed by switching load to a neighbor station with sufficient spare capacity in the near term. These short-term measures defer the need for expanding the substation transformer at least for the next five years examined in the study.

**Q. Please explain the method you used to recognize geographical differences in the computation of a system-wide marginal cost estimate for bulk and non-bulk stations.**

A. PSNH's standard distribution rates do not vary by geographical location, thus, the MCOSS calculates a system-wide average to be useful for rate design. The estimated marginal station cost per-kW of peak load was weighted by the retail peak-load share corresponding to those stations that are due for expansion. A zero marginal cost is implicitly assumed for any areas not likely to require capacity investments. This represent about 80 percent of the PSNH's retail load in the case of bulk stations. An equivalent approach was used to estimate a system-wide marginal cost for non-bulk stations. About 95 percent of the areas served by non-bulk stations will not need to be upgraded for peak load reasons in the 2020-2024 timeframe. The marginal non-bulk per-kW cost was further adjusted to recognize that the majority of PSNH's retail customers (or 83 percent of the total load) are not served from these lower voltage substations but from smaller primary transformers.

**Q. Did you use any other adjustment factor to marginal investment in distribution substation?**

A. In the case of bulk stations, converting the marginal investment per kW of capacity to a dollar per-kW of peak load carrying capability required adjusting the unit cost by the 75 percent planning design factor. The marginal station cost by voltage level, both on a system-wide and on a locational basis (averaged for all the areas of expansion) are provided in Attachment MCOSS-1.

**Q. How did you time-differentiate the marginal distribution substation costs?**

A. The MCOSS includes an analysis of historical hourly bulk substation data during the last four years (2015 - 2018) which determined that the majority of the stations are more likely to experience their peak load between 11:00 am and 7:00 pm on summer weekdays, and primarily in July and August. The MCOSS developed allocation factors based on relative probability of distribution peak to allocate the annualized marginal costs to peak and off-peak periods. The current on-peak period in TOD distribution rates is defined as 7:00 am to 8:00 pm on weekdays, year-round. This peak period is too broad and fails to effectively signal the hours with the highest cost of distribution service. As informed by the MCOSS, there is only a subset of those hours that are responsible for the investment in distribution substation and primary feeder infrastructure.

**Q. What method did you employ to estimate the marginal primary distribution trunk-line feeder costs?**

A. The Company's capital plan for the next five years does not include primary trunk line feeder expansion related to meeting peak load, therefore the marginal cost for that component is zero.

**Q. Please explain your computation of local marginal distribution facilities costs**

A. The MCOSS estimates the cost that is incurred by PSNH when connecting the most typical (average customer) in a given rate class to the grid. The Company is responsible to provide customer access in perpetuity, unless the site is permanently abandoned. The design demand that the Company considers when installing a transformer and local lines is the maximum load that the customers connected to those facilities are expected to impose on the local distribution system. This is distinctly different from the coincident peak demands that are considered when designing plant at the upstream distribution voltage levels.

The facilities cost approach estimates the current opportunity cost or "rental" value of the average customer connection in the class. The study identifies the current installed cost and size of secondary transformer, primary lines, and/or secondary lines for different customer configurations in a rate class, net of up-front customer contributions. The marginal local distribution costs may vary depending on whether there are overhead or underground facilities. Single versus three-phase connections also have different connection costs. To estimate the typical installed cost of distribution facilities, PSNH provided an extensive sample of work orders associated with customer connection jobs in the most recent three years (2015-2017). I considered the sample to be large enough to be representative of the entire service territory. The work orders included specific descriptions on the work, cost of connection before and after customer contributions, transformer capacity and number of accounts per jobs for each service classification. I computed the typical per-kW installed cost of connection by customer class, after taking into account customer contributions and using appropriate weighting factors where corresponding for overhead and underground facilities, single and three-phase facilities within each customer class.

**Q. Why are the investments in distribution facilities not related to changes in on-going energy usage?**

A. The utility will typically invest in distribution facilities when a customer is initially connected to the grid, and again whenever the facilities are replaced at the end of their service life. At that point, the cost of the new transformer may have changed due to inflation, technological change, or design standards. It may also occur, albeit less frequently that a significant change in the customer mix at the specific site has taken place, due to construction of data intensive buildings in the premise or other factors. In some cases, the customer may install limited-load equipment or equivalent measures that might warrant a lower level of design demand. A customer may be entitled to a lower than the standard average design demand in cases where the utility has installed an automated load control system or other energy-efficiency measures that permanently reduce its maximum demand.

**Q. Describe your method to estimate marginal customer costs.**

A. The third part of the study involves analysis of the marginal customer-related costs, i.e., those costs unrelated to energy or demand. These include the installed cost of the meter and service drop, customer accounts and customer service and informational expenses. Once the annualized installed cost of these assets for all customer categories are estimated, marginal O&M and marginal customer service expenses are added to obtain total marginal customer costs. As part of this analysis, street lighting marginal costs are also computed, taking into account typical investment per fixture.

**Q. What elements of the study relied on historical information?**

A. The components of MCOSS that rely on historical information include the marginal distribution O&M expenses, the marginal customer service and informational expenses, and the marginal customer account expenses. Marginal customer account and service expenses represent the cost of adding and maintaining a new customer account. These costs were estimated from a review of dollars of expense per unit of capacity or customer for the last five years from FERC Form 1 data. Weighting factors were obtained from the ACOSS, based on relative labor requirements and frequency of each activity by customer class. In addition, loading factors were projected based on how administration and general

(A&G) expenses and general plant have historically changed with increments in O&M or plant.

## V. USE OF MARGINAL COSTS FOR CLASS REVENUE REQUIREMENT ALLOCATION

**Q. What cost allocation approach should be used in setting rate class' revenue responsibility?**

A. Class revenue targets should consider the differences in the costs of providing service to different customer classes. There is extensive literature on efficient public pricing (or utility pricing) that supports the use of marginal costs both to set marginal-cost based rate structures and to set class revenue targets. Due to the economies of scale inherent to a natural monopoly such as that of the utility distribution business, rates that are set equal to marginal costs will not match the utility's revenue requirement and an adjustment will be needed to ensure that the utility recovers a fair return on required investments and operational costs. Reconciling marginal costs of service with the utility's overall distribution revenue requirement should be done in a manner that minimizes large departures from efficient electricity consumption levels by customer class. Many utilities rely to different degrees on marginal cost studies for rate design but not for revenue allocation. The most commonly employed cost of service studies by utilities for utility revenue allocation purposes in the U.S., and one adopted by PSNH is all prior rate cases is the ACOS or embedded cost approach. Any change in the method to allocate revenue responsibilities across customer classes may entail efficiency gains but also income distributional impacts that would need to be considered.

**Q. Is the use of marginal costs for revenue requirement allocation purposes supported by economic literature?**

A. One of the best-known approaches is that discussed by Ramsey (1927).[1] Ramsey demonstrated that to maximize social welfare, those consumers with relatively more inelastic demands for a particular good will need to pay a higher markup above marginal cost as compared to less price elastic consumer types to make the utility whole. Price elasticity of demand is defined as the percentage change in quantity demanded divided by the percent change in price. All other things equal, rates that follow the Ramsey inverse-price elasticity method raise more revenue from price inelastic customers per unit of demand, because this minimizes total deviations from the optimal consumption level that would occur in absence of market failures (if customers could just pay marginal costs).

**Q. Do U.S. utilities use the Ramsey approach in setting marginal cost-based revenue allocations?**

A. In practice, utilities that use marginal costs for decisions on class revenue requirements typically use a variant of Ramsey pricing termed "equal percentage of marginal costs" ("EPMC") methodology due to lack of precise elasticity data by rate classes and legacy methods. Under the EPMC method, each rate class is allocated a share of the revenue requirement based on its share of total class marginal cost revenues. EPMC is generally used to set the starting point for class revenue targets in California and Nevada, among other states. EPMC is however, rarely applied without any modifications to it based on available qualitative evidence of customer reaction to prices, or to mitigate any effects of

[1] *Ramsey, F.P. 1927. A contribution to the theory of taxation.* Economic Journal 37, 47–61

a rate shock that may be caused by changes in bills. This is because otherwise, the most price-inelastic rate class would receive the same mark-up as classes with lower price-elastic customers, even though they are likely to respond differently to the price changes, leading to a loss in consumer surplus. Lower marginal cost mark ups for customers with high price demand elasticity may also be necessary to avoid an uneconomic bypass of the grid. It is inefficient that customers largely deviate from the usage that they would have made of the grid if rates were set at marginal costs.

**Q. Is it possible to set efficient rates using an ACOS-based revenue requirement allocation?**

A. To avoid cross-subsidization, marginal costs should ideally be used as the starting point of the rate class revenue target, i.e., making sure that no rate class pays below the marginal costs of serving them. When using an embedded cost of service as the basis to set class revenue targets, particular attention should still be paid to whether the resulting class targets always ensure that all customers pay at least their marginal cost of service. In developing the ACOSS, I introduced modifications to the allocators to the extent that it was feasible to keep in mind marginal cost principles. This moves the class revenue targets in an appropriate direction, relative to efficient allocation of rates, although not enough to make the two methods comparable. An ACOS-based cost allocation may in some cases give less room to undertake the appropriate split of cost recovery between fixed and energy charges. In other words, rate design may be more constrained in its ability to send an efficient price signal (closer to marginal cost) in the volumetric portion of the rate. For example, the ACOSS may suggest to allocate more costs to demand charges even if this overestimates the incremental cost impact of an increase of kW by the customer. The ACOSS also is limited because it relies on accounting information and is not granular enough to establish time-differentiation or cost differentiation by voltage level.

**Q. Did you compute marginal cost revenues by class to determine a comparison with ACOS study revenue targets and EPMC?**

A. Yes. Once the marginal unit costs are estimated, I followed these steps:

1. The annual marginal (per-kWh) costs of distribution substations, the annual marginal (per-kVA, per-kW per customer) local facilities costs, and the annual marginal customer costs by class, were multiplied by the respective customer class' billing determinants. This required using the test-year data on hourly usage by class (in the case of distribution substations), the assumed design demand (in the case of local facilities) and the test-year customer and meter numbers (for marginal customer costs).
2. The resulting marginal cost revenues by class were then added across all customer classes and compared to the total distribution revenue requirement to determine the overall distribution revenue gap.
3. The percent increase required to bring overall marginal costs revenues to revenue requirement was used to allocate the revenue gap to all customer classes.

**Q. How do the marginal cost revenues compare to current rate revenues by class?**

A. According to my calculations, all customer classes are currently paying at least their marginal cost of service. This is the first condition for efficiency. However, the current revenue shares by class are misaligned with the percentage of marginal cost revenues by class. While revenue requirement split across rates does not need to exactly keep the same proportions of class marginal cost revenues, they should ideally only depart from those proportions in inverse relationship to their price demand elasticity. Table 1 below compares current revenues with marginal cost revenues by rate class. The residential rate currently contributes to 56.32 percent of the total distribution rate revenues, even though their proportional share of total marginal costs is 68.60 percent. In contrast, all other major rate classes, i.e., rate G, GV revenues are in close proportion to their share of overall marginal costs, albeit slightly higher. The LG rate contributes far above its marginal cost revenues. This outcome would suggest a shift of cost recovery towards the residential class would be required for a more efficient allocation of sunk costs among customer classes.

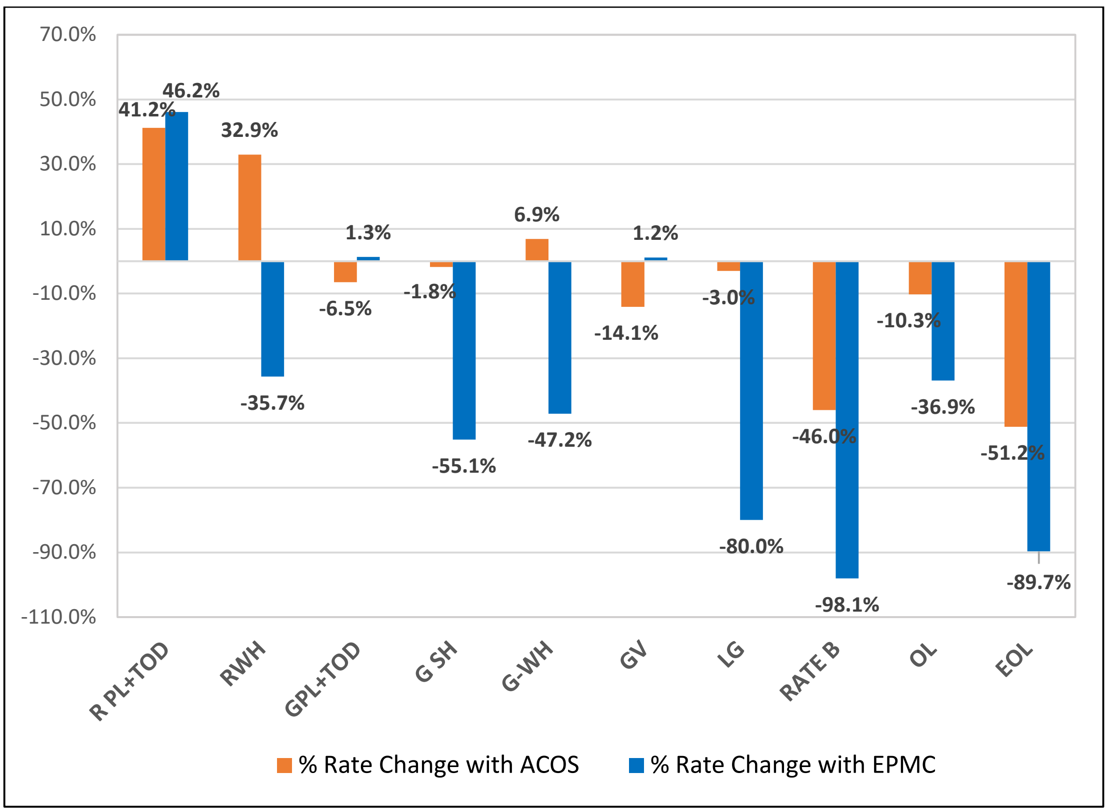
**Table 1: Comparison of Current Distribution Revenues and Marginal Cost Revenues by Rate Class**

| Rate Class | Current Revenue | MCOS Revenues | Current Revenue Class Share | Marginal Cost Class Share |
|---|---|---|---|---|
| | (000 $) | (000 $) | (%) | (%) |
| R PL+TOD | $197,030 | $169,601 | 56.32% | 68.60% |
| R LCS | 447 | 287 | 0.13% | 0.12% |
| RWH | 4,188 | 1,587 | 1.20% | 0.64% |
| GPL+TOD | 83,801 | 49,997 | 23.95% | 20.22% |
| G SH | 201 | 53 | 0.06% | 0.02% |
| G LCS | 29 | 25 | 0.01% | 0.01% |
| G-WH | 137 | 42 | 0.04% | 0.02% |
| GV | 36,149 | 21,536 | 10.33% | 8.71% |
| LG | 18,814 | 2,219 | 5.38% | 0.90% |
| RATE B | 1,489 | 17 | 0.43% | 0.01% |
| OL | 4,501 | 1,672 | 1.29% | 0.68% |
| EOL | 3,077 | 187 | 0.88% | 0.08% |
| **Total** | **$349,862** | **$247,223** | 100.00% | 100.00% |

**Q. What are the required rate changes required by EPMC and how it would compare with ACOS-based rate changes by class?**

A. The ACOSS revenue targets for proforma test year 2018 suggest a comparable percent change is required for the Residential rates, to improve inter-class equity. Both studies suggest that under each method, the residential class should increase by more than the overall distribution revenue requirement increase. The EPMC suggests that all customers except for the residential standard and TOD rate are paying more than their fair costs and should see a reduced rate. However, the ACOSS offer very different result for all other rate classes, in particular the LG rate and the smaller rate classes, as compared to the EPMC-based allocation. The smaller rate classes are particularly sensitive to changes in revenue allocation method. Figure 1 below illustrates the impact in terms of required distribution rate changes under each method.

**Figure 1: Percent Changes over Current Distribution Rates as Suggested by EPMC and Compared to ACOS Method for Test Year 2018**




**Q. What are the main take-aways from this comparison?**

A. A number of factors are behind the large differences in results. Marginal costs are forward looking, while embedded costs are, to a large extent, backward looking. Marginal costs are driven by current technology and design criteria, while the ACOSS uses accounting costs that are a function of prior planning practices and are heavily influenced by past regulatory policies. In addition, the EPMC allocations are based on a more granular analysis as to the use of different components of the distribution system by voltage level as well as by time of day and season. For example, in the case of LG customers, the ACOSS allocates plant and O&M expense for feeders below the 34.5-kV level, even though these customers are connected at or above that level. They also receive an allocation of sunk costs even though the marginal cost of primary feeders is zero for the upcoming planning period. Both studies reveal that the current rate targets are misaligned with cost causation.

## VI. RECOMMENDATIONS ON RATE STRUCTURES

**Q. What goals are served by using marginal costs in ratemaking in addition to sending efficient price signals?**

A. The efficiency goal in utility rate designs need to be balanced with equity, rate stability, customer acceptance (avoidance of rate shock), and price understandability goals. The goal of 'fairness' in utility pricing sometimes is equated with the protection of low-income users, but this income redistribution related goal should not be ideally addressed through standard rate design, to avoid distortion of the price signal that all customers see. A plan to gradually increase small customers' distribution fixed charges to the level of marginal customer costs would give more efficient signals about the true cost of being connected to the system and would mitigate subsidies to low-use customers from high-use customers. Equity may also be interpreted as ensuring that all customer classes are paying at least the marginal cost of the service they receive, and if needed, an efficiently allocated share of the revenue gap. The difference or marginal cost revenue gap needs to be allocated to rate classes in the least distorting manner. Any class paying less than marginal cost plus the efficient allocation of the revenue gap is being subsidized by other customers, the utility's investors, or both. Cross-subsidies may also occur within a given class. To some extent these cross-subsidies can be ameliorated using the proper rate structure.

**Q. How can utility rates be structured to reflect marginal costs?**

A. Rates need to be designed as a multi-part structure that preserves economically efficient price signals for the key components of the service. Costs that do not vary with on-going changes in usage should be recovered in fixed charges to keep volumetric (e.g., per-kW or per-kW) charges as close as possible to the underlying, near-term marginal costs.

**Q. What are your recommendations for PSNH'S distribution rates?**

A. PSNH's marginal costs associated with peak load growth are low on a system-wide average basis over the five-year planning period. The current per-kWh charges in PSNH's distribution rates generally exceed the per-kWh marginal costs of upstream distribution service, suggesting an artificially high incentive to conserve system-wide. Ideally, an efficient distribution rate would be a three-part rate that reflects the underlying structure of marginal costs of service. In particular, this rate would have the following rate components:

1. A monthly customer charge that recovers marginal customer-related costs (meter, service drop, customer-related expenses such as meter reading, billing, customer accounting, and customer information).

2. A monthly distribution facilities charge per customer's kW of design demand, that recovers the marginal costs of local distribution facilities; as discussed earlier this

concept of customer design demand is different from metered monthly customer maximum demand. Fluctuations of electricity usage by the customer from one month to the next do not free up transformer capacity available to serve him and other local connected customers on a long-term basis. Ideally, the billing systems would include a record of design demand or maximum average connected load for a given rate class. The charge can also be established as a per-contract kW charge for demand-metered customers, with the contract demand level set at no less than the highest 30-minute maximum demand recorded over the past 12 or 18 months.

3. Energy charges (ideally seasonally differentiated and differentiated by peak and off-peak) that recover the estimated marginal distribution substation and marginal trunk line feeder costs. This charge is applicable to incremental and decremental usage and it is critical to keep it as close as possible to marginal cost. It can be replaced by an on-peak demand charge for demand-metered customers.

The fixed charge may also be designed to include the marginal monthly distribution facilities costs (converted on a per-customer monthly charge using the average customer's design demand for the class), if a contract or facilities demand charge to recover those costs is not separately included in rates. This approach works better if the rate class includes relative homogeneous customers with comparable maximum non-coincident demands.

Recovery of other costs above marginal cost of service should ideally be included, to the extent feasible, in the fixed component of the rate. Generally, customer demand is less sensitive with respect to increases in the fixed component of the rates. Changes in the monthly bill from month to month are directly related to the specific volumetric charge. The caveat is that customer charges should not be increased to the point that it makes a customer disconnect from the grid, or relocate to other utility's service territory. Such an outcome would represent uneconomic bypass. Table 2 shows marginal unit cost for each component of the service using the existing time of day periods and the year-round construct of the existing rates. Marginal local distribution facilities costs are shown separately, in two alternative ways – per customer and per kW of monthly design or contract demand. Marginal primary costs are also shown in two alternative ways – per kW of monthly metered demand and per kWh of usage. While these cost figures have not been marked up to reflect the class revenue targets, they are nevertheless useful to assess the efficiency of the price signals in the current rates.

**Table 2: Marginal Unit Cost of Distribution Using Existing Distribution Rates**

| | | Local Distribution Facility Marginal Costs | | Time-Related Primary Distribution Marginal Cost | | |
|---|---|---|---|---|---|---|
| **Service Classification** | **Customer Cost** | **Monthly Facilities Cost per Customer** | **Per-kW of Contract or Design kW** | **TOU Period** | **Per-kW of Max demand** | **Per-kWh** |
| | **($/Cust./mo)** | **($/Cust/mo)** | **($/kW-mo)** | | **($/kW-mo)** | **($/kWh)** |
| **R-P&L** | 14.91 | 16.96 | 1.46 | All | 0.46 | 0.00063 |
| **R-OTOD** | 17.15 | 16.96 | 1.46 | Peak | 0.46 | 0.00168 |
| | | | | Off-Peak | 0.00 | 0.00001 |
| **R-C-WH** | 1.75 | 1.21 | 1.46 | All | 0.46 | 0.00063 |
| **R-UC-WH** | 1.75 | 1.21 | 1.46 | All | 0.46 | 0.00063 |
| **R-LCS** | 2.39 | 3.70 | 1.46 | All | 0.46 | 0.00063 |
| **GS-P&L-P1** | 15.04 | 27.22 | 1.39 | All | 0.46 | 0.00063 |
| **GS-P&L-P3** | 32.64 | 52.26 | 1.99 | All | 0.46 | 0.00063 |
| **GS-OTOD-P1** | 20.06 | 27.22 | 1.39 | Peak | 0.46 | 0.00168 |
| | | | | Off-Peak | 0.00 | 0.00001 |
| **GS-OTOD-P3** | 44.33 | 52.26 | 1.99 | Peak | 0.46 | 0.00168 |
| | | | | Off-Peak | 0.00 | 0.00001 |
| **GS-UC-WH** | 1.75 | 0.88 | 1.39 | All | 0.46 | 0.00063 |
| **GS-LCS-P1** | 2.39 | n.a. | 1.39 | All | 0.46 | 0.00063 |
| **GS-LCS-P3** | 7.41 | n.a. | 1.99 | All | 0.46 | 0.00063 |
| **GS-SH** | 4.52 | 5.66 | 1.39 | All | 0.46 | 0.00063 |
| **GV□** | 1,238.71 | na | na | All | 0.46 | 0.00063 |
| **LG** | 1,245.15 | na | na | Peak | 0.46 | 0.00059 |
| | | | | Off-Peak | 0.00 | 0.00001 |

**Q. What is your recommendation with regard to the residential fixed charges?**

A. In the case of the Residential rate, the current fixed charge is below the marginal monthly customer costs. Because of this, too much of the class revenue target is being recovered through the kWh charge. There is currently a large difference between the existing volumetric charge and the underling marginal costs stated on a per-kWh. My recommendation was to lower the volumetric charge in existing standard residential rate R towards the estimated marginal unit costs, but limit increases in customer charges to avoid rate shock. A monthly facilities charge, converted to a per-customer charge for the average residential customer, would be about $17 per month. Together with the marginal residential customer-related costs of $14.91, this would mean a total fixed charge of $31.87, before considering the required increase of the Company's revenue requirement. PSNH is proposing a moderate increase of the customer charge to $13.89. This charge allows for 93 percent recovery of the marginal customer costs. A gradual plan to further increase small customers' fixed charges to the level of monthly marginal customers and facilities costs should be considered in the future to give more efficient signals about the true opportunity cost of keeping the customer connected to the system. Such process would require ensuring that low income customers receive appropriate bill rebates through a mechanism that tracks eligibility conditions.

**Q. What is your recommendation for General Service rates?**

A. My recommendation for rates GV and LG, is to increase their fixed charges towards a level closer to the marginal costs. In the General Service rate schedule, both the demand charge and kWh charges are too high as compared to marginal costs. The block charges are unnecessary because the price differential between block 2 and block 3 is too small to influence usage decisions. It would more appropriate to eliminate blocks or at least reduce them to have no more than two block charges. The size of the first block should be set so that the majority of customers in the class face the tail block price for at least a portion of their usage every month. The price of the tail kWh block would reflect the marginal cost, and recovery of sunk costs would take place in the first tier. In this economic environment of slow demand growth and sufficient grid capacity to meet most of the projected load forecast, declining block rates are helpful to bring the marginal prices closer to marginal costs of serving them. However, block rate structures with more than two tiers create confusion, since the customer does not know at which point in time within the month he has reached the next usage block level. Thus, block prices are not as effective to induce efficient usage behavior.

**Q. What is the main benefit of lowering the volumetric charge?**

A. With a lower kWh or metered kW charge that reflects the low cost that incremental usage imposes on PSNH's system, customers are not artificially constrained for using their electrical appliances or driven to use other forms of energy because of disproportionately high usage charges. They will have the opportunity to increase electricity use, while lowering their average cost of electricity and as a result, improve the efficiency with which society's resources are allocated. A change in usage in the off-peak period has no bearing on the station loading.

**Q. What is your recommendation regarding the appropriate time of use periods for those rates that are time-differentiated?**

A. The current Residential TOD rate is overestimating the peak marginal cost of service. A peak to off-peak differential of 13 cents per kWh, year round, is not cost reflective, even within the summer season. The broad peak period also leads no room for customers to save electricity costs in any substantial manner unless all usage is shifted to late night and weekends. The peak charge should be reduced and the off-peak charge may need to be increased to make sure that the absolute price differential between the peak and off-peak charges is closer to the underlying marginal costs price differentials. Developing efficient rates also requires to have seasonally-differentiated charges.

**Q. Overall, what is your conclusion on PSNH's proposed rate designs as filed in this proceeding?**

A. PSNH's proposed rate designs recognize that while a primary goal of rate design is to seek economic efficiency, consideration should be given to the need for gradualism. The Company is undertaking an increase in rates for all rate classes by increasing all rate components over the current rates. Instead of recovering the full revenue increase entirely on the volumetric charges of the rates, it has proposed a partial increase in the customer charges. This brings the fixed charge closer to the marginal customer cost for the residential class. Additional work is required towards efficient distribution rates that consider recovering not only marginal customer costs plus marginal facilities cost recovery on a more fixed basis, similar to what is already reflected in the optional time of day rates. This will allow decreasing the volumetric rates and more effectively signal the low prevailing incremental distribution cost of serve an additional kW. A stricter application of marginal cost principles to rate design would have resulted in even higher fixed charges for residential and general service customers. PSNH has not taken steps in the current rate case to improve the structure of the time of day rates by shortening the peak period. The introduction of seasonality in distribution rates is another aspect that is not being addressed at this time, but it is among the aspects of potential rate design that will merit consideration in later rate cases. Improved use of the system and reduced cross subsidies between classes are the main benefits to ratepayers that result from continuing to take into account marginal costs in rate design in the future.

**Q. Does this conclude your testimony?**

A. Yes, it does.

# Marginal Cost of Distribution Service Study and Implications for Rate Design

**Prepared for the Public Service Company of New Hampshire**

**d/b/a Eversource Energy**

**May 28, 2019**

Economists INCORPORATED

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# Eversource Energy's Marginal Cost of Distribution Service Study and Implications for Rate Design

## I. INTRODUCTION

Eversource Energy ("Eversource", or "The Company"), retained Economists Incorporated (EI) to develop a system-wide marginal cost of service (MCOS) study for electricity distribution service in New Hampshire for a five-year planning period 2020-2024. EI has developed a forward-looking MCOS study that takes into account the Company's prevailing engineering design standards and planning process. In the context of the utility distribution service the marginal cost requires evaluating the utility's response, from a planning perspective, with respect to either a small anticipated change in the use of the system in a given hour, or changes in customer connections or service requirements.[1]

This report summarizes the approach that EI has followed to estimate upstream distribution marginal costs by voltage level of service, local distribution facilities costs, and marginal customer costs, and presents a summary of the results.

The results of the MCOS study are helpful to inform the direction of reforms that are needed for Eversource's distribution rate designs, in terms of both structure and rate levels of rate components Additionally, it provides useful information on the time-differentiated distribution value of load reductions from customer-sited distributed generation (DG), as well as other distributed energy resources (DERs).

[1] Marginal cost also represents the value of those resources in their next best alternative use, known as the opportunity cost.

# II. UPSTREAM DISTRIBUTION MARGINAL COSTS

## A. Elements of Primary System

The NH system is varied and complex. The starting point for the MCOS study was identifying the various elements and voltage levels of the Company's distribution system. Eversource's primary voltage distribution system includes the following main elements:

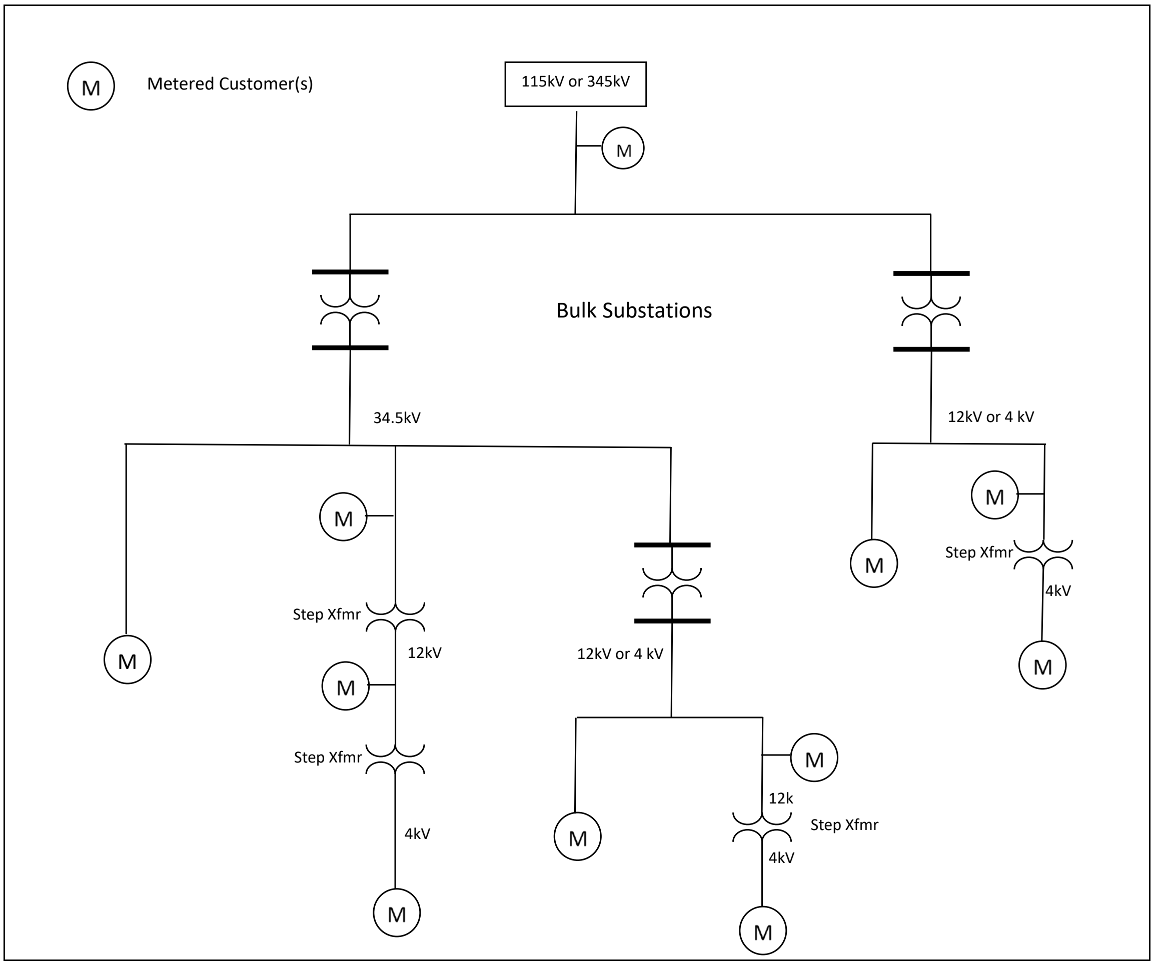
- Bulk stations that are fed from the transmission system (115kV) and typically convert power to 34 kV or directly to 12 kV;
- Distribution (non-bulk) substations that convert the load coming from the bulk station to either 12 kV or 4 kV, and
- Trunk-line primary feeders.

The Company's has an extensive 34.5kV system. About 340,000 customers (about 83 percent of the total load) are connected to this system through small pole mounted step transformers that convert the load coming from the bulk system to either 12.47 kV or 4.16 kV.

The remaining 17% of the load is served from distribution substations. A small share of Eversource's service territory customers (about 30 MW) receive electricity from bulk stations that are located in Vermont. At the more local level, Eversource's distribution facilities include local primary taps, primary-to-secondary transformers, switchgear, secondary lines, and service drop.

Eversource also serves wholesale distribution customer loads from its system. These loads need to be taken into account when designing the system, just as the retail loads, and are therefore considered when estimating the share of stations that are likely to require capacity expansion to meet peak load growth. The simplified diagram below illustrates the variety of configuration of Eversource's distribution system.

**Figure 1. Typical Eversource New Hampshire's Electricity Distribution System**




## B. Marginal Substation Investment

The MCOS builds upon an in-depth review of the Company's budgeted investments for the upcoming planning period (2020-2024). Eversource, like many other distribution utilities, generally predicts the required investments in non-bulk substations to meet expected peak load with sufficient confidence within a timeframe of two to three years. Projected distribution capital expansion investments further into the future are less certain and subject to further review based on monitoring growth of station peak loads as the date approaches. The 2019 MCOS utilizes project expectations as per the Company's capital plan over years 2020-2024, along with information on expected peak load conditions over the study period to compute marginal station costs. This is necessary to provide a longer-term view of marginal costs.

EI reviewed the current and expected station peak loading as well as existing transformer nameplate ratings over the next five years. Our review identified specific bulk station and distribution substation expansion projects that are needed to address N-0 and N-1 limitations in meeting peak load reliably based on the current standards. These projects generally involve replacement of existing substation transformers with one (or two) larger transformers. The investments intend to address existing or expected overload conditions, serve new step industrial or commercial load additions, and/or offload nearby substations. A number of stations not currently in the Company's capital plan are at or moderately exceeding the maximum peak loading allowed under N-1 criteria. However, upon consultation with the Company, a decision was made not to include these stations in the MCOSS since the Company does not expect to address those N-1 related capacity needs in the current five-year horizon.

EI isolated the cost associated with capacity expansion to meet peak load from other costs that are purely due to modernize the station or improve the condition of the transformer and would need to be incurred regardless of changes in peak load. In general, the MCOS excludes investments that are incurred to address a change in the substation configuration, including such items as replacement of electromechanical relays with numerical relays, or other reliability-related costs that are unique to the stations and not triggered by growth in load (or avoided by load reductions). Projects associated with retirement of obsolete equipment were entirely left out of the MCOS calculation, since these are one-time investments and are unlikely to be impacted by growth or reductions in load.

Going forward, the Company does not foresee significant peak load growth on a system-wide basis. Eversource's peak loads in the New Hampshire system are expected to grow generally at less than 1 percent per year throughout the study period, albeit growth is not uniform across the system. The Eastern and Central and regions are expected to experience relative larger than average demand growth due to higher commercial and industrial activity in a number of areas. The majority of the bulk stations and substations are expected to be able to accommodate load growth without needing a capacity addition over the upcoming five-year period.

To compute the marginal cost of bulk and distribution stations we divided the identified peak-load related station investments by the station's project added capacity. In the case of bulk stations, converting the marginal investment per kW of added capacity to a dollar per-kW of added peak load carrying capability required using the N-1 design criteria o adjustment factor. N-1 criteria in the case of bulk stations requires that the station is pre-loaded at no more than 75 percent of its normal (nameplate) rating, to avoid compromising the station long term emergency rating.[2] On the other hand, non-bulk substations are not generally considered for an upgrade until their loads begin to reach their long term emergency (LTE) rating. Thus, no adjustment factor was necessary in the case of marginal non-bulk substation costs.

## C. Operation and Maintenance Expenses

Marginal distribution station and line O&M expenses are a component of marginal distribution cost, since these expenses increase as the amount of plant in service does. EI reviewed the Company's FERC Form 1 annual distribution O&M expenses in recent years (2014-2018) and divided the annual expenses by the kW of non-coincident peak demand at bulk stations and distribution substations, separately for each type. Upon review of the annual expense per kW (in constant dollars) in these years, the average of the per-kW expenses over the four-year period was used to represent expected marginal O&M expenses per kW of station peak load.

## D. System-wide versus Locational Cost Estimates

Eversource's standard distribution rates do not vary by geographical location, therefore, EI calculated a system-wide marginal cost by multiplying the locational cost by the peak-load share of the bulk and distribution stations that are expected to require peak-load related capacity investments over the five-year period, as compared to total retail load. Because of the higher uncertainty of station peak load growth beyond a two-year timeframe, a number of non-bulk distribution capacity expansion investments are not formalized or specifically identified by area in the plan. The MCOS study uses available information of regional forecasts of annual peak load growth, along with information on known industrial step load additions at specific stations to estimate the share of the system potentially subject to requiring growth-related expansion over the full five-year period as new load materializes. A review of the station loads and nameplate ratings revealed that most areas, including some of the high-growth regions will have ample station capacity to serve peak loads during the study period. A zero marginal cost is implicitly assumed for these areas.

Finally, the marginal non-bulk substation cost was adjusted to recognize that they only serve about 17 percent of total retail load. The marginal bulk station cost was adjusted to take into account that about 2 percent of the retail load is not served from stations located in Vermont.

The bulk station and distribution substation marginal costs were annualized, both for the capacity-expansion areas and as a system-wide average marginal cost estimate, using marginal

[2] The emergency rating reflects the load that can be sustained for a limited number of hours before voltage instability (or ultimately loss of load) occurs.

O&M expenses, and loading factors.

## E. Time-differentiation

The annualized marginal bulk station and marginal distribution costs must be allocated to those peak hours in the year when load growth (or load reduction) is more likely to have an impact on the planned investment decisions. The MCOS uses hourly probability of peak factors for each typical weekday and weekend by month to allocate the annual marginal bulk station and non-bulk substation costs to hours and months. An analysis of the combined hourly load shapes of the entire set of Eversource's bulk substations during the four most recent four years (2015 through 2018) to account for weather variability showed that load growth that peak hours of weekdays in July and August drive distribution capacity expansion. Only a small number of bulk substations, representing about 10 percent of the total load, peak outside of the summer season, in the winter months of December or January. The months of July and August account for 97 percent of the system-wide annual probability of distribution peak. The remaining 3 percent falls in the months of September and June.

The seasonality observed in the resulting hourly marginal costs indicates that consideration of seasonality for Eversource's distribution rates may be required for efficient pricing. These results also show that the broad definition of the peak period in current rates (7 am to 8 pm, Monday through Friday) is not appropriate. Hours 11 am to 7 pm of summer weekdays include the highest marginal hourly distribution costs.

To be useful for potential revisions to time of day rates, as well as to guide other time of use rate analyses, EI evaluated a seasonal option where the summer season only includes July and August (Option A). We performed a sensitivity analysis as part of our statistical analysis around the peak hours and determined that a daily on-peak period, 11 am to 7 pm for weekdays provided the highest goodness of fit. This means that the price signals based on these periods are a good fit to the underlying time variation in marginal costs.

EI modelled marginal costs under a second alternative seasonal definition, to test the resulting average marginal costs in the event that the Company considered a less drastic shift towards seasonally differentiated rates. Under Option B, the total system-wide bulk station and distribution station marginal cost estimates would be averaged for a four-month summer period (June-Sep), with the same summer daily peak/off-peak definition as in Option A. Rates based on Option B seasons would produce less efficient price signals since the summer capacity marginal cost would be equally spread across the four months. Tables 1 and 2 below summarize the two alternative costing periods.

**Table 1. Alternative Time of Day and Seasonal Periods (Option A)**

| **Seasons** | | **Time of Use Hours** |
|---|---|---|
| Summer (July - August) | *Peak:* | Mo - Fri: 11 am to 7:00 pm; except Holidays |
| | *Off-Peak:* | Mo - Fri: 7:00 pm to 11:00 am; Weekends and Holidays: All hours |
| Winter (Jan – June & Sep-Dec) | *No TOD* | All hours |

**Table 2. Alternative Time of Day and Seasonal Periods (Option B)**

| **Seasons** | | **Time of Use Hours** |
|---|---|---|
| Summer (June - Sep) | *Peak:* | Mo - Fri: 11:00 am to 7:00 pm; except Holidays |
| | *Off-Peak:* | Mo - Fri: 7:00 pm to 11:00 am. Weekends and Holidays: All hours |
| Winter (Jan – May & Oct – Dec) | *No TOD* | All hours |

Table 3 shows the sum of system-wide marginal distribution bulk station and distribution station costs stated on a per-kW-month basis for a secondary-connected customer. The results are shown by peak/off-peak periods using three alternatives. Seasonal average marginal costs on a monthly basis are also shown for the sake of comparison.

**Table 3. Time-differentiated System-Wide Marginal per-kW Station Costs**

| | Marginal Cost of Bulk + Dist. Subs At Secondary Service (2019 $ per kW-mo) | Marginal Cost of Bulk + Dist. Subs At Primary Service (2019 $ per kW-mo) |
|---|---|---|
| **Current TOU** | | |
| Peak | $0.455 | $0.453 |
| Off-Peak | $0.004 | $0.004 |
| **Annual Average** | $0.459 | $0.457 |
| **Option A** | | |
| Winter, All hours | $0.017 | $0.016 |
| Summer (Jul & Aug) Peak | $2.546 | $2.532 |
| Summer (Jul & Aug) Off-Peak | $0.127 | $0.127 |
| **Winter Average** | **$0.017** | **$0.016** |
| **Summer Average (Jul-Aug)** | **$2.674** | **$2.659** |
| **Option B** | | |
| Winter, All hours | $0.000 | $0.000 |
| Summer (June-Sep) Peak | $1.291 | $1.283 |
| Summer (June-Sep) Off-Peak | $0.088 | $0.087 |
| **Winter Average** | **$0.000** | **$0.000** |
| **Summer Average (Jun-Sep** | **$1.378** | **$1.370** |

# III. LOCAL DISTRIBUTION FACILITIES

## A. Investment

The distribution facilities that are closer to the customers may include primary taps, line transformers and secondary lines. These are less extensively shared. Upon consultation with the Company, we confirmed that Eversource designs these facilities using engineering standards that take into consideration the number of customers who will use those facilities, and those customers' expected maximum loads over the service life of the transformer. Thus, the marginal cost of local distribution facilities is driven by the customer's "design demands", or connected load per customer. This level of kW represents the maximum load that customers may impose on the local system and does not change with variations of actual metered demand from month to month or even year to year.

The Company uses different transformer size standards for customers that use all electric appliances instead of relying partially on oil/gas, or customers with known air conditioning loads. The level of kW may also vary depending on the type of area (rural vs. urban), but specific information by area type was not available.

To estimate the typical installed cost of distribution facilities, Eversource provided an extensive sample of work orders associated with customer connection jobs for single-phase and three-phase customers in the most recent three years (2015-2017). The sample was considered large enough to be representative of the entire service territory. EI reviewed the work orders, and computed the average per kW cost of distribution facilities, after customer contributions as per the line extension policy, as well as average design demand by class. As a measure of design demand, the transformer capacity was divided by the number of customers that are typically served from one transformer, differentiating by rate class and type of service.

## B. Operation and Maintenance Expenses

Marginal distribution facility O&M expenses were estimated from historical data (2014-2018) given that there was not a forecast of O&M expenses. The O&M facilities expense per kW of design demand was separated into primary and secondary categories on the basis of miles of circuit. The total design demand was the product of customer counts and per-customer design demand estimates by customer category. EI also estimated the average street lighting O&M expense using per-light average expense over the period 2016-2018 and installed cost of the fixtures expected to be used by street lights going forward.

## C. Monthly Facilities Marginal Costs

Table 4 summarizes the monthly marginal local distribution facilities costs, stated as a fixed cost per kW of customer's design demand, and converted into a fixed cost per customer, using the class' average design demand. Table 6 summarizes the monthly marginal customer-related costs by rate class.

**Table 4: Summary of Monthly Marginal Local Distribution Facilities Costs by Rate Class**

| Customer Class | Monthly Facilities Cost per kW of Design Demand | Average Customer Design Demand | Monthly Facilities Cost for the Average Customer |
|---|---|---|---|
| | (2019 $/kW/mo) | (kW-mo) | ($/Cust/mo.) |
| Residential Power & Light | $1.46 | 11.63 | $16.96 |
| Residential OTOD | $1.46 | 11.63 | $16.96 |
| General Service Power & Light 1 Phase | $1.39 | 19.52 | $27.22 |
| General Service Power & Light 3 Phase | $1.99 | 26.32 | $52.26 |
| General Service OTOD 1 Phase | $1.39 | 19.52 | $27.22 |
| General Service OTOD 3 Phase | $1.99 | 26.32 | $52.26 |
| | | Average kW/ fixture | |
| Rate OL | $1.46 | 0.25 | $0.36 |
| Rate EOL | $1.46 | 0.01 | $0.01 |

# IV. MARGINAL CUSTOMER COSTS

## A. Meter and Service Drop

Eversource provided the current installed cost of a typical meter by rate class. EI annualized this cost using the appropriate economic carrying charge, as explained in Appendix 1 of this report. EI added an estimate of marginal meter O&M costs, based on recent meter O&M expenses and assuming that the meter O&M is proportional to the cost of the meter in order to estimate meter O&M differentiated by rate class. Appropriate loaders were applied to determine the annual marginal meter cost by class.

The second customer-related cost component is the service drop. The service drop generally serves a single customer. EI estimated the annualized installed cost of the service drop (after customer contributions) for all customer categories. A weighted average installed cost per customer service drop was computed separately for single phase and three phase, as well as by overhead vs. underground, based on customers using each type of service drop by rate class.

## B. Customer Accounts and Customer Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are costs that are the function of a number of customers on the system. The MCOS study relied on weighting factors developed by Eversource for several customer accounts and customer service and informational expenses by class. EI reviewed the average per-customer expense for the period 2014-2018, stated in constant dollars and used as an estimate of future marginal expense of these set of accounts.

## C. Monthly Marginal Customer Costs

Table 5 summarizes the monthly marginal customer cost by rate class.

**Table 5. Summary of Monthly Marginal Customer Costs by Rate Class**

| | Marginal Customer Cost ($/Cust/mo.) |
|---|---|
| Residential Power & Light | $14.91 |
| Residential OTOD | $17.15 |
| Residential Controlled WH | $1.75 |
| Residential LCS | $2.39 |
| Residential Uncontrolled WH | $1.75 |
| General Service Power & Light 1 Phas | $15.04 |
| General Service Power & Light 3 Phas | $32.64 |
| General Service OTOD 1 Phase | $20.06 |
| General Service OTOD 3 Phase | $44.33 |
| General Service Uncontrolled WH | $1.75 |
| General Service LCS 1 Phase | $2.39 |
| General Service LCS 3 Phase | $7.41 |
| General Service Space Heating | $4.52 |
| Rate GV | $1,238.71 |
| Rate GV – (Rate B; < 115 KV level) | $23.15 |
| Rate LG | $1,245.15 |
| Rate LG – (Rate B; < 115 KV level) | $23.67 |

# V. USING MARGINAL COSTS IN UTILITY PRICING

Economic theory holds that economic efficiency is maximized when customers face prices that reflect the marginal costs of using more units of the product or service. In the context of utility distribution service, economic efficiency can be measured as the ability of rates to enable a more efficient use and expansion of the utility's infrastructure and resources, ultimately allowing a lower overall cost of service.

## A. Efficient Distribution Marginal-Cost Based Rate Design

System-wide marginal costs are helpful for setting retail rates, both for determining the proper time-differentiation as well as to guide the level of the kWh and kW charges. Cost recovery of sunk costs (the difference between class marginal costs and allocated fixed costs) should primarily be reconciled through the least elastic portions of the bill, namely the basic service charge, to limit the deviation from efficient electricity consumption. An efficient distribution rate structure follows the marginal cost drivers of each component of service:

- Seasonal and time-of-day -differentiated per-kWh charges that recover marginal distribution substation and upstream feeder costs (the per-kWh charges may also be replaced with time-differentiated metered per-kW charges).
- A monthly fixed customer charge that recovers marginal customer-related costs, including the monthly costs of the meter, service drop, customer service and account expenses.
- A monthly distribution facilities charge based on customer's contract or facility design demand that recovers the marginal costs of local distribution facilities (local primary lines, transformers, secondary lines).

The facility charge may be levied on an estimate of the customer's design demand that reflects the per-kW customer monthly maximum demand or a contract demand that the customer is not expected to exceed at any time. This approach recognizes the more fixed nature of the costs of the transformers, which are sized to serve the long-term maximum demands of the few customers connected to it. Transformers and local lines are installed with sufficient capacity so that they do not need to be expanded as the local load grows, except for unusual circumstances.

Recovering marginal facilities costs through a monthly fixed charge (calculated on the basis of the class average design demand) may be appropriate if there are not significant differences in customer kW size within the rate class. When adopting a fixed monthly fixed charge it is best to differentiate within the class separating subgroups with homogeneous loads such as all-electric residential customers vs. gas heating customers.

## B. Marginal Cost Use for DER and NEM Evaluation

Time-differentiated marginal costs associated with the upstream distribution grid over the upcoming utility's planning period provide useful information to evaluate and design DER pricing models. An important goal in determining distribution rates for DERs is to ensure that these resources are connected to the utility system in the most efficient way possible and to avoid uneconomic bypass, which would increase the overall cost of service.

Marginal cost information is important to provide the right incentives to locate where and when those resources can bring the most value to the system. Following the marginal cost structure of distribution service involves separating the costs that are associated with local facilities from those that are time-related. In the case of Eversource, the MCOS results suggest that the highest primary distribution value of DER ouput is concentrated on mid-day to 7:00 pm in July and August. The system-wide time-differentiation results obtained in this MCOS study under Option A provide a reasonable basis upon which to inform DER compensation.

Ultimately, rates for DG customers need to contribute to cost recovery in a manner that is aligned with the costs they incrementally caused to the system, which may be higher or lower than regular customers. The cost allocation should be comparable to those of non-DER customers but the price mechanism may need to be different to avoid the limitations that may be present with excessive simplification of the standard rates.

## C. Summary of Marginal Unit Costs by Customer Class

In order to evaluate the efficiency in the existing distribution price signals, it is useful to compare them with marginal unit costs. Table 6 summarizes the marginal cost results following the structure of Eversource's existing distribution rates, i.e., using the TOU periods as in current TOD rates.

Primary distribution costs are stated on both demand and an energy basis. For maximum efficiency in price signals, these rate components should be time-differentiated by time of day and season. The local distribution facilities costs are shown in two alternative ways – per customer and per kW of monthly design or contract demand since these costs do not change with kWh usage or near-term changes in customer metered peak load. While these cost figures have not been marked up to reflect the class revenue targets, they are useful to assess the efficiency of the price signals in the current rates.

We note that the figures reflect marginal unit costs for each component of service, with no reconciliation for revenue targets. A mark-up to the components would be necessary to capture the class allocated revenue requirement.

## Table 6. Marginal Costs for 2020-2024 averaged according to Existing Rate Structures

| | | Local Distribution Facility Marginal Costs | | Time-Related Primary Distribution Marginal Cost | | |
|---|---|---|---|---|---|---|
| **Service Classification** | **Customer Cost** | **Monthly Facilities Cost per Customer** | **Per-kW of Contract or Design kW** | **TOU Period** | **Per-kW of Max demand** | **Per-kWh** |
| | **($/Cust./mo)** | **($/Cust/mo)** | **($/kW-mo)** | | **($/kW-mo)** | **($/kWh)** |
| **R-P&L** | 14.91 | 16.96 | 1.46 | All | 0.46 | 0.00063 |
| **R-OTOD** | 17.15 | 16.96 | 1.46 | Peak | 0.46 | 0.00168 |
| | | | | Off-Peak | 0.00 | 0.00001 |
| **R-C-WH** | 1.75 | 1.21 | 1.46 | All | 0.46 | 0.00063 |
| **R-UC-WH** | 1.75 | 1.21 | 1.46 | All | 0.46 | 0.00063 |
| **R-LCS** | 2.39 | 3.70 | 1.46 | All | 0.46 | 0.00063 |
| **GS-P&L-P1** | 15.04 | 27.22 | 1.39 | All | 0.46 | 0.00063 |
| **GS-P&L-P3** | 32.64 | 52.26 | 1.99 | All | 0.46 | 0.00063 |
| **GS-OTOD-P1** | 20.06 | 27.22 | 1.39 | Peak | 0.46 | 0.00168 |
| | | | | Off-Peak | 0.00 | 0.00001 |
| **GS-OTOD-P3** | 44.33 | 52.26 | 1.99 | Peak | 0.46 | 0.00168 |
| | | | | Off-Peak | 0.00 | 0.00001 |
| **GS-UC-WH** | 1.75 | 0.88 | 1.39 | All | 0.46 | 0.00063 |
| **GS-LCS-P1** | 2.39 | n.a. | 1.39 | All | 0.46 | 0.00063 |
| **GS-LCS-P3** | 7.41 | n.a. | 1.99 | All | 0.46 | 0.00063 |
| **GS-SH** | 4.52 | 5.66 | 1.39 | All | 0.46 | 0.00063 |
| **GV** | 1,238.71 | na | na | All | 0.46 | 0.00063 |
| **LG** | 1,245.15 | na | na | Peak | 0.46 | 0.00059 |
| | | | | Off-Peak | 0.00 | 0.00001 |

# APPENDIX 1:  DERIVATION OF ANNUAL MARGINAL COSTS

# ANNUALIZATION PROCESS

This Appendix includes the explanation of the various steps to derive the annualized bulk station, distribution substation and primary feeder costs, the annualized marginal cost for local primary and secondary distribution facilities, marginal cost per lighting fixture, and the annualized cost of meters and service drop by rate class.

The MCOS estimated annualized marginal cost for each component of service by multiplying the marginal investments for each plant type by the annual economic carrying charge, expressed as a percentage. The marginal investment is adjusted using a general plant loading factor and a plant-related A&G loading factor.

Converting estimates of marginal distribution plant investment into annual costs for use in rate design and other cost analysis, requires estimating an economic carrying charge (ECC). The first year ECC represents today's market or "rental" value per kW. Subsequent years' ECC are calculated by applying annual inflation in such a way that the present value of the stream of annual revenues equals the present value of the revenue requirement associated with owning the asset.

To these costs, EI added marginal O&M expenses, adjusted by non-plant related A&G expenses. Revenue requirement for working capital including cash, materials, supplies and prepayments is also added to obtain the annualized marginal costs of different types of plant.

A summary of the calculation of these components is provided below.

**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE**
**D/B/A, EVERSOURCE ENERGY**
**TABLE A.1.1. DERIVATION OF ANNUAL BULK AND NON-BULK SUBSTATION COST**

| | **System-Wide Average of Marginal Cost** | | **MCs in Capacity-Expanding Areas** | |
|---|---|---|---|---|
| | Bulk Station | Non-bulk Substation | Bulk Station | Non-bulk Substation |
| | (2019 $/kW) | (2019 $/kW) | (2019 $/kW) | (2019 $/kW) |
| Locational marginal Investment per kW of added peak load carrying capability (2020-2024) | $182.51 | $250.60 | $182.51 | $250.60 |
| Share of total retail peak load at expanding stations | 20.3% | 5.5% | | |
| Share of total retail load fed from station type | 98.2% | 17.5% | | |
| System-wide marginal Investment per kW of Peak Loa | $36.33 | $2.41 | | |
| Economic Carrying Charge | 8.43% | 8.43% | 8.43% | 8.43% |
| General Plant Loader | 1.0697 | 1.0697 | 1.0697 | 1.0697 |
| Plant-related A&G Loader | 1.0002 | 1.0000 | 1.0000 | 1.0000 |
| Subtotal Annualized Capital Costs | $3.28 | $0.22 | $16.46 | $22.60 |
| O&M Expenses | | | | |
| Annual Marginal O&M Expenses per kW of Peak Loa | $1.51 | $0.07 | $7.45 | $7.57 |
| A&G Loading 1.049 (Non-plant Related) | 1.049 | 1.049 | 1.049 | 1.049 |
| Working Capital Revenue Requirement | | | | |
| Material, Supplies and Prepayments | $0.066 | $0.004 | $0.330 | $0.453 |
| Cash Working Capital Allowance | $0.020 | $0.001 | $0.098 | $0.100 |
| **Total Annualized Marginal Station Cost ($/kW-yr)** | **$4.94** | **$0.30** | **$24.70** | **$31.09** |

**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE**
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**TABLE A.1.2. DERIVATION OF ANNUAL DISTRIBUTION FACILITIES COSTS**

| | R-P&L | R-OTOD | R-C-WH | R-UC-WH | R-LCS | GS-P&L-P1 | GS-P&L-P3 | GS-OTOD-P1 | GS-OTOD-P3 | GS-UC-WH | GS-LCS-P1 | GS-LCS-P3 | GS-SH | OL | EOL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Residential Power & Light | Residential OTOD | Residential Controlled WH | Residential Uncontrolled WH | Residential LCS | General Service Power & Light 1 Phase | General Service Power & Light 3 Phase | General Service OTOD 1 Phase | General Service OTOD 3 Phase | General Service Uncontrolled WH | General Service LCS 1 Phase | General Service LCS 3 Phase | General Service Space Heating | Rate OL | Rate EOL |
| | ---------------- (2019 Dollars per kW of Design Demand) ---------------- | | | | | | | | | | | | | | |
| Marginal Investment per kW of Design Demand after customer contributions ($/kW) | $118.24 | $118.24 | $118.24 | $118.24 | $118.24 | $118.24 | $189.85 | $118.24 | $189.85 | $118.24 | $118.24 | $189.85 | $118.24 | $118.24 | $118.24 |
| General Plant Loading | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 | 1.070 |
| Annual Economic Carrying Charge | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% |
| Annualized Costs | $11.50 | $11.50 | $11.50 | $11.50 | $11.50 | $11.50 | $18.46 | $11.50 | $18.46 | $11.50 | $11.50 | $18.46 | $11.50 | $11.50 | $11.50 |
| Annual O&M Expense per kW of Design Demand With A&G Loading x 1.0487 | 5.71 | 5.71 | 5.71 | 5.71 | 5.71 | 4.96 | 4.96 | 4.96 | 4.96 | 4.96 | 4.96 | 4.96 | 4.96 | 5.71 | 5.71 |
| Subtotal Distribution Facilities Marginal Costs | $17.21 | $17.21 | $17.21 | $17.21 | $17.21 | $16.46 | $23.42 | $16.46 | $23.42 | $16.46 | $16.46 | $23.42 | $16.46 | $17.21 | $17.21 |
| Working Capital Rev. Req. | | | | | | | | | | | | | | | |
| Material, Supplies and Prepayments | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.34 | 0.21 | 0.34 | 0.21 | 0.21 | 0.34 | 0.21 | 0.21 | 0.21 |
| Cash Working Capital Allowance | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.07 | 0.07 |
| **Total Annualized Marginal Facilities Cost per kW of Design Demand ($/kW-yr)** | **$17.50** | **$17.50** | **$17.50** | **$17.50** | **$17.50** | **$16.74** | **$23.83** | **$16.74** | **$23.83** | **$16.74** | **$16.74** | **$23.83** | **$16.74** | **$17.50** | **$17.50** |

**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE**
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**TABLE A.1.3. ANNUAL CUSTOMER-RELATED MARGINAL UNIT COST**
**RESIDENTIAL AND GENERAL SERVICE**

| | R-P&L | R-OTOD | R-C-WH | R-LCS | R-UC-WH | GS-P&L-P1 | GS-P&L-P3 | GS-OTOD-P1 | GS-OTOD-P3 | GS-UC-WH | GS-LCS-P1 | GS-LCS-P3 | GS-SH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Residential Power & Light | Residential OTOD | Residential Controlled WH | Residential LCS | Residential Uncont. WH | GS P&L 1 Phase | GS P&L 3Phase | GS OTOD 1 Phase | GS OTOD 3 Phase | GS Uncont. WH | GS LCS 1 Phase | GS LCS 3 Phase | GS Space Heating |
| | ---------------- (2019 Dollars per Customer) ---------------- | | | | | | | | | | | | |
| Meter | | | | | | | | | | | | | |
| Installed Meter Cost | $57.35 | $152.35 | $57.35 | $57.35 | $57.35 | $57.35 | $269.69 | $269.69 | $764.07 | $57.35 | $57.35 | $269.69 | $169.96 |
| With General Plant Loading | $61.34 | $162.96 | $61.34 | $61.34 | $61.34 | $61.34 | $288.49 | $288.49 | $817.33 | $61.34 | $61.34 | $288.49 | $181.81 |
| Annual ECC related to Capital Investment | 9.37% | 9.37% | 9.37% | 9.37% | 9.37% | 9.37% | 9.37% | 9.37% | 9.37% | 9.37% | 9.37% | 9.37% | 9.37% |
| Subtotal Annualized Meter Costs | $5.75 | $15.27 | $5.75 | $5.75 | $5.75 | $5.75 | $27.03 | $27.03 | $76.57 | $5.75 | $5.75 | $27.03 | $17.03 |
| Meter O&M Expenses with A&G Loading | $10.29 | $27.33 | $10.29 | $10.29 | $10.29 | $10.29 | $48.38 | $48.38 | $137.07 | $10.29 | $10.29 | $48.38 | $30.49 |
| Service drop | | | | | | | | | | | | | |
| Installed Service Cost | | | | | | | | | | | | | |
| With General Plant Loading x 1.0697 | $1,090.18 | $1,090.18 | - | - | - | $1,090.18 | $2,718.40 | $1,090.18 | $2,718.40 | - | - | - | - |
| Annual ECC related to Capital Investment | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% | 9.09% |
| Annualized Service Drop Costs | 99.12 | 99.12 | - | - | - | 99.12 | 247.15 | 99.12 | 247.15 | - | - | - | - |
| Customer services | | | | | | | | | | | | | |
| Customer Accounts Expenses | $57.77 | $57.77 | $4.41 | $11.71 | $4.41 | $59.286 | $59.286 | $59.286 | $59.286 | $4.4 | $11.6 | $11.6 | $5.7 |
| Customer Service & Informational Expenses | $0.16 | $0.16 | $0.00 | $0.00 | $0.00 | $0.159 | $0.159 | $0.159 | $0.159 | $0.0 | $0.0 | $0.0 | $0.0 |
| With non-plant A&G Loading x 1.0487 | $60.75 | $60.75 | $4.63 | $12.28 | $4.63 | $62.34 | $62.34 | $62.34 | $62.34 | $4.63 | $12.20 | $12.20 | $5.96 |
| **Sub-total Annualized Cost of Meter, Service and Customer Expenses** | $175.90 | $202.46 | $20.66 | $28.31 | $20.66 | $177.49 | $384.89 | $236.86 | $523.12 | $20.66 | $28.23 | $87.60 | $53.48 |
| Working Capital Rev. Req. | | | | | | | | | | | | | |
| Material, Supplies and Prepayments | $2.08 | $2.26 | $0.11 | $0.11 | $0.11 | $2.08 | $5.43 | $2.49 | $6.39 | $0.11 | $0.11 | $0.52 | $0.33 |
| Cash Working Capital | $0.89 | $1.11 | $0.19 | $0.28 | $0.19 | $0.91 | $1.39 | $1.39 | $2.51 | $0.19 | $0.28 | $0.76 | $0.46 |
| **Total Annual Customer Marginal Costs** | **$178.87** | **$205.83** | **$20.96** | **$28.71** | **$20.96** | **$180.48** | **$391.72** | **$240.74** | **$532.01** | **$20.96** | **$28.62** | **$88.88** | **$54.26** |

# PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
# D/B/A, EVERSOURCE ENERGY
## TABLE A.1.4. ANNUAL CUSTOMER-RELATED MARGINAL UNIT COST
## MIDDLE AND LARGE GENERAL SERVICE CUSTOMERS

| | GV | LG |
|---|---|---|
| Meter | | |
| Installed Meter Cost | $709.00 | $726.82 |
| With General Plant Loading x 1.0697 | $758.42 | $777.48 |
| Annual ECC related to Capital Investment | 9.37% | 9.37% |
| Annualized Meter Costs | $71.05 | $72.83 |
| Meter O&M Expenses with A&G loading | $127.19 | $130.39 |
| Customer services | | |
| Customer Accounts Expenses | $544.86 | $612.92 |
| Customer Service & Informational Expenses | $13,264.01 | $13,264.01 |
| With non-plant A&G Loading x 1.0487 | $14,481.37 | $14,552.73 |
| **Sub-total Annualized Cost of Meter and Customer Expenses** | $14,679.60 | $14,755.95 |
| Working Capital Rev. Req. | | |
| Material, Supplies and Prepayments | $1.37 | $1.40 |
| Cash Working Capital | $183.52 | $184.46 |
| **Total Annual Customer Marginal Costs** | **$14,864.49** | **$14,941.82** |

**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE**
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**TABLE A.1.5. ANNUAL CUSTOMER-RELATED MARGINAL COST FOR STREET LIGHTING**

| | **Rate OL** | | | **Rate EOL** |
|---|---|---|---|---|
| | HP-Sodium | Metal Halide | LED | LED |
| Service drop | | | | |
| Installed Service Cost | $61.61 | $56.81 | 22.41 | 22.41 |
| With General Plant Loading x 1.0697 | $65.91 | $60.77 | $23.98 | $23.97 |
| Annual ECC related to Capital Investment | 9.09% | 9.09% | 9.09% | 9.09% |
| Annualized Service Drop Costs | $5.99 | $5.52 | $2.18 | $2.18 |
| Customer services | | | | |
| Customer Accounts Expenses | $26.76 | $26.76 | $26.76 | $18.30 |
| Customer Service & Informational Expenses | $0.00 | $0.00 | $0.00 | $0.00 |
| With non-plant A&G Loading x 1.0487 | $28.06 | $28.06 | $28.06 | $19.19 |
| **Sub-total Annualized Cost of Service Drop and Customer Service** | $34.05 | $33.59 | $30.24 | $21.37 |
| Working Capital Rev. Req. | | | | |
| Material, Supplies and Prepayments | $0.12 | $0.11 | $0.04 | $0.04 |
| Cash Working Capital | $0.35 | $0.35 | $0.35 | $0.24 |
| **Total Annual Customer Marginal Costs** | **34.52** | **34.05** | **30.64** | **21.66** |

# APPENDIX 2: MCOSS SUPPORTING WORKSHEETS

## Table A.2.1 Marginal Investment in Bulk Substations (2020-2024)

| Region | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Total (2019$) | Existing Capacity | New | Added | Average Cost per kW added | Average Cost per added Carrying Capability |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | *(000 $), $2019* | | | | | *MW* | | *$/kW* | *$/kW* |
| **Total Bulk Investment (Peak Related)** | **2,500.00** | **9,000.00** | **5,000.00** | **5,000.00** | **4,000.00** | **2,000.00** | **$27,500** | **451.2** | **652.1** | **200.9** | **$136.88** | **$182.51** |

## Table A.2.2 Marginal Investment in Non-Bulk Substations (2020-2024)

| | 2021 | 2022 | 2023 | 2024 | Total (2019$) | Existing Capacity | New | Added | Average Cost per Added Carrying Capability |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | **MW** | **MW** | **MW** | **$/kW** |
| **Total Non-Bulk Investment (Peak Related)** | 400.00 | 1,600.00 | 1,600.00 | 1,600.00 | **5,200** | **16.8** | **37.5** | **20.8** | **$250.60** |

## Table A.2.3 Retail Peak Load-Share in Areas of Capacity Expansion Need

| | Year 2024 |
|---|---|
| **Total Retail Peak served from Bulk Stations (a)** | **1,973.25** |
| **Total Retail Peak Load in Capacity Expansion Need Areas (b)** | **399.78** |
| ***Ratio (b)/(a)*** | ***20.26%*** |

## Table A.2.4 Marginal O&M Expenses of Bulk Station and Non-Bulk Substation Peak Load

| **Bulk Distribution Station O&M** | 2014 | 2015 | 2016 | 2017 | 2018 | Average |
|---|---|---|---|---|---|---|
| | *Year* | | | | | |
| Annual Bulk Station O&M Expenses (000 Dollars) | $14,630.27 | $15,193.45 | $15,563.97 | $14,831.24 | $16,318.65 | |
| Weather- normalized Bulk Station NCP (MW) | 2,244 | 2,284 | 2,126 | 2,237 | 2,262 | |
| O&M expense per kW of Bulk Station Peak Load | $6.52 | $6.65 | $7.32 | $6.63 | $7.22 | |
| Weighted Labor and Materials Cost Index (2019=1.00) | 0.88 | 0.90 | 0.91 | 0.94 | 0.98 | |
| Bullk Station O&M expense per kW of Peak Load (2019 Dollars) | $7.39 | $7.38 | $8.03 | $7.06 | $7.37 | |
| Marginal Station O&M Expense per kW of Peak Load in Areas of Growth over 2020-2024 ($/kW-yr) | | | | | | $7.45 |
| Station Peak-load Share in areas of capacity expansion | | | | | | 20.26% |
| **System-wide Marginal Bulk Station O&M Expense ($/kW-yr)** | | | | | | **$1.51** |

| **Non-Bulk Distribution Station O&M** | 2014 | 2015 | 2016 | 2017 | 2018 | Average |
|---|---|---|---|---|---|---|
| | *Year* | | | | | |
| Annual Distribution Subst. and Trunkline O&M Expenses (000 Dollars) | $2,217.72 | $2,303.09 | $2,359.25 | $2,248.18 | $2,398.91 | |
| Weather-normalized Dist. Substation NCPs (MW) | 335 | 341 | 317 | 334 | 327 | |
| O&M expense per kW of Dis. Substation Peak Load (2019 $/kW) | $6.63 | $6.76 | $7.44 | $6.74 | $7.33 | |
| Weighted Labor and Materials Cost Index (2019=1.00) | 0.88 | 0.90 | 0.91 | 0.94 | 0.98 | |
| Dis. Substation O&M expense per kW of Peak Load (2019 $/kW) | $7.51 | $7.50 | $8.16 | $7.18 | $7.49 | |
| Marginal Station O&M Expense per kW of Peak Load in Areas of Growth over 2020-2024 ($/kW-yr) | | | | | | $7.57 |
| Station Peak-load Share in areas of capacity expansion | | | | | | 5.51% |
| System-wide Marginal Distribution Substation O&M Expense ($/kW-yr) | | | | | | $0.42 |
| Share of the Company load served from a distribution substation | | | | | | 17.46% |
| **System-wide Marginal Distribution Station O&M Expense ($/kW-yr)** | | | | | | **$0.07** |

## Table A.2.5. Bulk and Non-Bulk Station Costs by TOU Periods and Seasons (Current Periods)

**Current TOU Periods**

Probability of System Peak:

| Year-Round **Peak** | Year-Round **Off-Peak** |
|---|---|
| **99.2%** | **0.8%** |

| | **Bulk Substation** | | **Dist. Substation** | |
|---|---|---|---|---|
| | **Year-round** | | **Year-round** | |
| | **Peak** | **Off-Peak** | **Peak** | **Off-Peak** |
| **Losses Through Levels** | | | | |
| Secondary | 1.0518 | 1.0518 | 1.0417 | 1.0417 |
| Primary | 1.0460 | 1.0460 | 1.0360 | 1.0360 |
| **Annual MC (System Wide-Average)** | | | | |
| $/kW-yr (Total) | 4.94 | | 0.30 | |
| $/kW-yr (Costing Period) | 4.9029 | 0.0417 | 0.30 | 0.00 |
| $ per kW per month | 0.4086 | 0.0035 | 0.0247 | 0.0002 |
| Hours by Costing Period | 3,246 | 5,514 | 3,246 | 5,514 |
| $/kWh | 0.0015 | 0.0000 | 0.0001 | 0.0000 |
| **Cost per kWh ($/kWh)** | | | | |
| Secondary Cost adjusted by losses | 0.0016 | 0.0000 | 0.0001 | 0.0000 |
| Primary Cost | 0.0016 | 0.0000 | 0.0001 | 0.0000 |
| **Cost per kW ($/kW-mo)** | | | | |
| Secondary Cost adjusted by losses | 0.4298 | 0.0037 | 0.0257 | 0.0002 |
| Primary Service | 0.4274 | 0.0036 | 0.0256 | 0.0002 |

## Table A.2.6. Bulk and Non-Bulk Station Costs by TOU Periods and Seasons (Option A Periods)

**Option A - TOU**

Probability of Distribution System Peak:

| Peak Summer (July & August) | | All Other Months |
|---|---|---|
| **Peak** | **Off-Peak** | **All Hours** |
| 92.38% | 4.62% | 2.99% |

| | Bulk Substation | | | Dist. Substation | | |
|---|---|---|---|---|---|---|
| | Summer | | Winter | Summer | | Winter |
| | Peak | Off-Peak | All Hours | Peak | Off-Peak | All Hours |
| **Losses Through Levels** | | | | | | |
| Secondary | 1.0518 | 1.0518 | 1.0518 | 1.0417 | 1.0417 | 1.0417 |
| Primary | 1.0460 | 1.0460 | 1.0460 | 1.0360 | 1.0360 | 1.0360 |
| **Annual MC (System Wide-Average)** | | | | | | |
| $/kW-yr (Total) | | 4.94 | | | 0.30 | |
| $/kW-yr (Costing Period) | 4.5679 | 0.2287 | 0.1481 | 0.2761 | 0.0138 | 0.0090 |
| $ per kW per month | 2.2840 | 0.1143 | 0.0148 | 0.1381 | 0.0069 | 0.0009 |
| Hours by Costing Period | 341 | 1,123 | 7,296 | 341 | 1,123 | 7,296 |
| $/kWh | 0.0134 | 0.0002 | 0.0000 | 0.0008 | 0.0000 | 0.0000 |
| **Cost per kWh ($/kWh)** | | | | | | |
| Secondary Cost adjusted by losses | 0.0141 | 0.0002 | 0.0000 | 0.0008 | 0.0000 | 0.0000 |
| Primary Cost | 0.0140 | 0.0002 | 0.0000 | 0.0008 | 0.0000 | 0.0000 |
| **Cost per kW ($/kW-mo)** | | | | | | |
| Secondary Cost adjusted by losses | 2.4024 | 0.1203 | 0.0156 | 0.1438 | 0.0072 | 0.0009 |
| Primary Service | 2.3891 | 0.1196 | 0.0155 | 0.1430 | 0.0072 | 0.0009 |

## Table A.2.7. Bulk and Non-Bulk Station Costs by TOU Periods and Seasons (Option B Periods)

**Option B - TOU**

Probability of Distribution System Peak:

| Summer (June - Sep) | | All Other Months |
|---|---|---|
| **Peak** | **Off-Peak** | **All Hours** |
| 93.65% | 6.35% | 0.000% |

| | Bulk Substation | | | Dist. Substation | | |
|---|---|---|---|---|---|---|
| | Summer | | Winter | Summer | | Winter |
| | Peak | Off-Peak | All Hours | Peak | Off-Peak | All Hours |
| **Losses Through Levels** | | | | | | |
| Secondary | 1.0518 | 1.0518 | 1.0518 | 1.0417 | 1.0417 | 1.0417 |
| Primary | 1.0460 | 1.0460 | 1.0460 | 1.0360 | 1.0360 | 1.0360 |
| **Annual MC (System Wide-Average)** | | | | | | |
| $/kW-yr (Total) | | 4.94 | | | 0.30 | |
| $/kW-yr (Costing Period) | 4.6305 | 0.3141 | 0.00 | 0.2799 | 0.0190 | 0.0000 |
| $ per kW per month | 1.1576 | 0.0785 | 0.00 | 0.0700 | 0.0047 | 0.0000 |
| Hours by Costing Period | 681 | 2,247 | 5,832.00 | 681 | 2,247 | 5,832 |
| $/kWh | 0.0068 | 0.0001 | 0.00 | 0.0004 | 0.0000 | 0.0000 |
| **Cost per kWh ($/kWh)** | | | | | | |
| Secondary Cost adjusted by losses | 0.0072 | 0.0001 | 0.00 | 0.0004 | 0.0000 | 0.0000 |
| Primary Cost | 0.0071 | 0.0001 | 0.00 | 0.0004 | 0.0000 | 0.0000 |
| **Cost per kW ($/kW-mo)** | | | | | | |
| Secondary Cost adjusted by losses | 1.2177 | 0.0826 | 0.00 | 0.0729 | 0.0049 | 0.0000 |
| Primary Service | 1.2109 | 0.0821 | 0.00 | 0.0725 | 0.0049 | 0.0000 |

## Table A.2.8 Installed Cost of Single-Phase Distribution Facilities

| Construction Type | Average Gross Facilities Cost per kVA (2019$) | Average Facilities Cost (after CIAC) per KVA (2019$) | Average OH/UG split | Average Transformer Size (kVA) | No. of Residential customers per transformer 1-ph | Average kVA per Customer (residential) | No. of GS 1-ph Customers per Transformer | Average kVA per Customer (GS) |
|---|---|---|---|---|---|---|---|---|
| UG 1 PH | $174.04 | $126.77 | 0.21 | **50** | 2.6 | 19.23 | 1.55 | 32.26 |
| OH 1 PH | $191.79 | $115.98 | 0.79 | **25** | 2.6 | 9.62 | 1.55 | 16.13 |
| Average Cost (after CIAC) | | **$118.24** | | | Weighted Average kVA (1-ph) | **11.63** | Weighted Average kVA (1-ph) | **19.52** |

## Table A.2.9 Installed Cost of Three-Phase Distribution Facilities

| Construction Type | Average Gross Facilities Cost per kVA (2019$) | Average Net Facilities Cost (after CIAC) per KVA (2019$) | Average OH/UG split | Average Transformer Cost per kVA (2019$) | Median Transformer Size (KVA) | Max Size (KVA) | No. of customers per transformer GS-3ph | kVA per GS Customer | |
|---|---|---|---|---|---|---|---|---|---|
| UG | $168.87 | $141.26 | 0.39 | $80.77 | 50.0 | 175.0 | 1.9 | 26.32 | |
| OH | $229.67 | $220.91 | 0.61 | $84.49 | 50.0 | 150.0 | 1.9 | 26.32 | |
| Average Cost (After CIAC) | | | **$189.85** | | | | Weighted Average kVA (3-ph) | **$26.32** | **kVA** |

## Table A.2.10 Marginal O&M Expenses for Distribution Facilities

| | Year 2014 | 2015 | 2016 | 2017 | 2018 | Average |
|---|---|---|---|---|---|---|
| Secondary Portion of Distribution Facility O&M Expenses (000's Dollars) | $4,290.6 | $3,968.8 | $4,397.1 | $4,253.5 | $4,105.1 | |
| Primary Portion of Distribution Facility O&M Expenses (000's Dollars) | $25,939.3 | $28,609.9 | $32,561.3 | $29,665.4 | $31,227.8 | |
| Design Demand on Secondary (MW) | 6,552 | 6,544 | 6,605 | 6,674 | 6,757 | |
| Design Demand on Primary (MW) | 6,704 | 6,696 | 6,758 | 6,829 | 6,914 | |
| Weighted Labor and Materials Cost Index (2019 = 1.00) | 0.88 | 0.90 | 0.91 | 0.94 | 0.98 | |
| Secondary Distribution Facilities O&M Expense Per kW of Design Demand (2019 Dollars/kW) | $0.74 | $0.67 | $0.73 | $0.68 | $0.62 | |
| Primary Distribution Facilities O&M Expense Per kW of Design Demand (2019 Dollars/kW) | $4.38 | $4.74 | $5.28 | $4.63 | $4.61 | |
| Annual Primary Distribution Facilities O&M Expense per kW for Primary Customer ($/kW-yr) | | | | | | **$4.73** |
| Total Annual Primary and Secondary Distribution Facilities O&M Expense per kW for Secondary Customer ($/kW-yr) | | | | | | **$5.45** |

## Table A.2.11 Lighting O&M per Light

| | 2017 | 2018 | Average |
|---|---|---|---|
| Total Lighting Operation & Maintenance Expenses ('000 Dollars) | $633 | $641 | |
| Number of ST Lights | 25,770 | 25,770 | |
| O&M Expenses Per Light (Dollars) | 24.56 | 24.88 | |
| Weighted Labor and Materials Cost Index (2019=1.00) | 93.88 | 97.92 | |
| Lighting Expense Per Light (2019 Dollars) | 0.26 | 0.25 | |
| Estimated Annual Weighted Lighting O&M Expense for Planning Period | | | **$0.26** |

# Table A.2.12 Annualized ST Fixture Cost

**HP SODIUM**

| | 50W | 70 | 100 | 150 | 250 | 400 | 1,000 |
|---|---|---|---|---|---|---|---|
| | (2019 Dollars per fixture) | | | | | | |
| Marginal Investment per fixture | $435 | $433 | $459 | $465 | $532 | $683 | $1,100 |
| With General Plant Loading x 1.0697 | $465.84 | $462.88 | $490.67 | $497.71 | $568.83 | $730.28 | $1,176.38 |
| Annual Economic Carrying Charge Related to Capital Investment | 11.10% | 11.10% | 11.10% | 11.10% | 11.10% | 11.10% | 11.10% |
| Annualized Costs | $51.72 | $51.39 | $54.48 | $55.26 | $63.15 | $81.08 | $130.61 |
| Lighting O&M Expenses | $0.26 | $0.26 | $0.26 | $0.26 | $0.26 | $0.26 | $0.26 |
| With A&G Loading x 1.0487 (non-plant related) | $0.27 | $0.27 | $0.27 | $0.27 | $0.27 | $0.27 | $0.27 |
| Annual Fixture-related Costs | $51.99 | $51.66 | $54.75 | $55.53 | $63.43 | $81.35 | $130.88 |
| Working Capital | | | | | | | |
| Material and Supplies | $4.50 | $4.47 | $4.74 | $4.81 | $5.49 | $7.05 | $11.36 |
| Prepayments | $3.88 | $3.85 | $4.08 | $4.14 | $4.73 | $6.08 | $9.79 |
| Cash Working Capital Allowance | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 |
| Total Working Capital | $8.41 | $8.35 | $8.85 | $8.98 | $10.26 | $13.16 | $21.18 |
| Revenue Requirement for Working Capital | $0.85 | $0.84 | $0.89 | $0.90 | $1.03 | $1.32 | $2.13 |
| Total Annual Marginal Per-Light Cost | **$52.84** | **$52.50** | **$55.64** | **$56.43** | **$64.46** | **$82.67** | **$133.01** |

**METAL HALIDE**

| | 50 W | 70 W | 100 W | 175 | 250 W | 400 W | 1,000 |
|---|---|---|---|---|---|---|---|
| | (2019 Dollars per fixture) | | | | | | |
| Marginal Investment per fixture | $471 | $510 | $497 | $522 | $561 | $684 | $1,135 |
| With General Plant Loading x 1.0697 | $503.36 | $545.49 | $531.57 | $557.92 | $600.02 | $732.19 | $1,213.68 |
| Annual Economic Carrying Charge Related to Capital Investment | 11.10% | 11.10% | 11.10% | 11.10% | 11.10% | 11.10% | 11.10% |
| Annualized Costs | $55.89 | $60.56 | $59.02 | $61.94 | $66.62 | $81.29 | $134.75 |
| Lighting O&M Expenses | $0.26 | $0.26 | $0.26 | $0.26 | $0.26 | $0.26 | $0.26 |
| With A&G Loading x 1.0487 (non-plant related) | $0.27 | $0.27 | $0.27 | $0.27 | $0.27 | $0.27 | $0.27 |
| Annual Fixture-related Costs | $56.16 | $60.83 | $59.29 | $62.21 | $66.89 | $81.56 | $135.02 |
| Working Capital | | | | | | | |
| Material and Supplies | $4.86 | $5.27 | $5.13 | $5.39 | $5.79 | $7.07 | $11.72 |
| Prepayments | $4.19 | $4.54 | $4.42 | $4.64 | $4.99 | $6.09 | $10.10 |
| Cash Working Capital Allowance | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 |
| Total Working Capital | $9.08 | $9.84 | $9.59 | $10.06 | $10.82 | $13.20 | $21.85 |
| Revenue Requirement for Working Capital | $0.91 | $0.99 | $0.96 | $1.01 | $1.09 | $1.33 | $2.20 |
| Total Annual Marginal Per-Light Cost | **$57.07** | **$61.82** | **$60.25** | **$63.23** | **$67.98** | **$82.89** | **$137.22** |

**LED LIGHTS**

| | 50 W | 75 W | 100 W | 150 W | 250 W | 400 W |
|---|---|---|---|---|---|---|
| | (2019 Dollars per fixture) | | | | | |
| Marginal Investment per fixture | $606.08 | $594.97 | $602.72 | $651.33 | $715.96 | $942.17 |
| With General Plant Loading x 1.0697 | $648.33 | $636.44 | $644.73 | $696.72 | $765.86 | $1,007.84 |
| Annual Economic Carrying Charge Related to Capital Investment | 11.10% | 11.10% | 11.10% | 11.10% | 11.10% | 11.10% |
| Annualized Costs | $71.98 | $70.66 | $71.58 | $77.35 | $85.03 | $111.90 |
| Lighting O&M Expenses | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| With A&G Loading x 1.0487 (non-plant related) | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Annual Fixture-related Costs | $71.98 | $70.66 | $71.58 | $77.35 | $85.03 | $111.90 |
| Working Capital | | | | | | |
| Material and Supplies | $6.26 | $6.15 | $6.23 | $6.73 | $7.40 | $9.73 |
| Prepayments | $5.39 | $5.30 | $5.36 | $5.80 | $6.37 | $8.39 |
| Cash Working Capital Allowance | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Total Working Capital | $11.66 | $11.44 | $11.59 | $12.53 | $13.77 | $18.12 |
| Revenue Requirement for Working Capital | $1.17 | $1.15 | $1.16 | $1.26 | $1.38 | $1.82 |
| Total Annual Marginal Per-Light Cost | **$73.15** | **$71.81** | **$72.75** | **$78.61** | **$86.41** | **$113.72** |

## Table A.13. Meter O&M Expense

| | 2014 | 2015 | 2016 | 2017 | 2018 | Average of 2016-2018 |
|---|---|---|---|---|---|---|
| Total Meter O&M Expenses (000's Dollars) | $5,218.5 | $6,886.5 | $6,868.5 | $6,238.0 | $4,949.7 | |
| Number of Metered Accounts | 556,182 | 554,127 | 557,589 | 561,881 | 567,397 | |
| Weighted Number of Accounts | 647,202 | 644,811 | 648,839 | 653,834 | 660,252 | |
| Meter Expense Per Weighted Account (Nominal dollars) | 8.06 | 10.68 | 10.59 | 9.54 | 7.50 | |
| Weighted Labor and Materials Cost Index (2019 = 1.00) | 0.88 | 0.90 | 0.91 | 0.94 | 0.98 | |
| Meter Expense Per Weighted Account (2019 Dollars) | $9.14 | $11.86 | $11.61 | $10.16 | $7.66 | |
| Estimated Annual Weighted Meter O&M Expense | | | | | | **$9.8** |

## Table A.2.14 Customer Account Expense per Weighted Customer Numbers

| **Customer Account Expense Calculation** | 2014 | 2015 | 2016 | 2017 | 2018 | Average 2016-2018 |
|---|---|---|---|---|---|---|
| Total Customer Accounts Expense (000's Dollars) | $32,405.1 | $34,225.9 | $29,651.4 | $28,814.3 | $28,563.9 | |
| Annual Number of Accounts | 557,145 | 555,082 | 558,529 | 562,695 | 568,170 | |
| Weighted Average Number of Accounts | 527,594 | 525,641 | 528,905 | 532,850 | 538,035 | |
| Customer Accounts Expense Per Weighted Account | $61.42 | $65.11 | $56.06 | $54.08 | $53.09 | |
| Labor Cost Index (2019 = 1.00) | 0.86 | 0.89 | 0.92 | 0.94 | 0.97 | |
| Customer Accounts Expense Per Weighted Customer (2019 Dollar: | $71.20 | $73.28 | $61.26 | $57.37 | $54.68 | |
| Estimated Annual Weighted Customer Accounts Expense | | | | | | **$57.77** |

## Table A.2.15 Customer Service and Informational Expense per Weighted Customer Numbers

| **Customer Service & Informational Expense Calculation** | 2014 | 2015 | 2016 | 2017 | 2018 | Average 2014-2018 |
|---|---|---|---|---|---|---|
| Total Customer Service and Informational Expense (000's Dollars) | $17,562.30 | $16,025.58 | $16,145.63 | $16,301.44 | $23,327.79 | |
| Average Number of Customers | 503,999 | 503,280 | 508,002 | 513,304 | 519,583 | |
| Weighted Average Number of Customers | 121,197,265 | 121,024,366 | 122,159,871 | 123,434,850 | 124,944,861 | |
| Customer Service and Informational Expense Per Weighted Custoı | $0.14 | $0.13 | $0.13 | $0.13 | $0.19 | |
| Labor Cost Index (2019 = 1.00) | 0.86 | 0.89 | 0.92 | 0.94 | 0.97 | |
| Customer Service and Informational Expense Per Weighted Custoı | $0.17 | $0.15 | $0.14 | $0.14 | $0.19 | |
| Estimated Annual Weighted Customer Service and Informational Expense | | | | | | **$0.16** |