REDACTED

BEFORE THE
STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET **DE 24-070**

IN THE MATTER OF: Public Service Company of New Hampshire
d/b/a Eversource Energy
Request for Change in Distribution Rates

DIRECT TESTIMONY

OF

Michael Ty Clark

January 24, 2025

TABLE OF CONTENTS

List of Attachments

I. <u>Introduction</u>

Q. Please state your full name.

A. My name is Michael Ty Clark.

Q. By whom are you employed and what is your business address?

A. I am a Vice President at Christensen Associates Energy Consulting LLC ("CA Energy Consulting"). My business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin, 53705.

Q. Please summarize your education and professional work experience.

A. I received a Bachelor of Arts degree in Economics from Utah State University in 2011, a Master of Science degree in Economics from Florida State University in 2013, and a Doctor of Philosophy degree in Economics from Florida State University in 2015. I have been employed by CA Energy Consulting since 2015 in positions of increasing responsibility. A copy of my curriculum vitae is attached as Attachment MTC-1.

Q. Have you previously testified before the New Hampshire Public Utilities Commission or other regulatory bodies?

A. Yes. I have testified before the New Hampshire Public Utilities Commission ("Commission") on behalf of the New Hampshire Department of Energy ("NHDOE") on marginal cost and rate design topics in Docket DE 23-039. I have also testified before the Florida Public Service Commission and the Michigan Public Service Commission.

II. <u>Purpose of Testimony</u>

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the New Hampshire Department of Energy.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to comment on the test-year billing determinants, Allocated Cost of Service ("ACOS") study, Marginal Cost of Service ("MCOS") study, and rate design items – including Time-of-Day ("TOD"), and revenue decoupling – that Public Service Company of New Hampshire d/b/a/ Eversource Energy ("PSNH" or "Company") has submitted in this proceeding.

Q. What are the major findings from your analysis?

A. The major findings from my analysis are as follows:

- Using relatively low test-year sales of energy, because of mild weather conditions, overstates PSNH's revenue requirement deficiency. PSNH should adjust billed sales during the test year using weather normalization.
- For classification of demand- and customer-related costs in the ACOS study, PSNH should investigate ways to improve the data and analysis of the current Minimum System Study ("MSS") methodology or, failing to make an improvement, explore alternative methods for distribution cost classification.
- For Rate R-OTOD 2, PSNH should incorporate a more consistent rate design methodology by increasing the customer and energy charges so that associated revenues match the proposed revenue target increase of 47%. Specifically, PNSH should increase the proposed customer charge from $23.67 to $24.22, which is closer to the marginal customer cost.

- PSNH should make the following adjustments to TOD periods and prices so that the associated rates better reflect cost drivers:
  - A seasonal TOD period with the peak period occurring only during months June through September (or alternatively July through August).
  - A TOD peak period of 2 to 8 p.m. weekdays, excluding holidays.
  - Apply the recommended TOD period changes to all TOD rates (R-OTOD2, G-OTOD, LG).
  - Update the peak and off-peak prices for TOD rates (R-OTOD2, G-OTOD, LG) using MCOS study results that allocate time-differentiated marginal costs to the recommended TOD periods with the Probability of Peak ("PoP") analysis.
- A Revenue Decoupling Mechanism ("RDM") should not be implemented by PSNH; however, if an RDM is to be implemented, then PSNH's proposed RDM should be modified in the following ways:
  - Include a soft 3% for under recoveries but over recoveries be applied in full;
  - Use forecasted billed sales when calculating the Revenue Decoupling Adjustment Factor ("RDAF"); and
  - Reduce cross-subsidies by calculating a separate RDAF for residential (R, R CWH, R UWH, R LCS, R OTOD2) and general service classes (G, G CH, G UWH, G LCS, G Space, G OTOD, GV, EV-2) as well as not decouple the LG, OL, and EOL rates.

Q. How is your testimony organized?

A. Section III provides discussion regarding weather normalization of test-year billing determinants. Section IV provides an overview and evaluation of PSNH's ACOS study. Section V provides an overview and evaluation of PSNH's MCOS study. Section VI evaluates PSNH's rate design, including TOD rates. Section VII assesses PSNH's revenue decoupling mechanism. Finally, Section VIII provides a summary of recommendations and conclusion.

III. Weather Normalization of Test-Year Billing Determinants

Q. What are test-year billing determinants?

A. Test-year billing determinants are the customer usage data needed to calculate bills during the test year, such as total sales of energy. Proposed rates are calculated based on test-year billing determinants and proposed revenue requirements. Test-year billing determinants serve as an estimate for expected sales in the future. If the test year had unusual weather, then test-year sales might not be reflective of sales in future years.

Q. What is weather normalization?

A. Energy consumption patterns can change based on weather. For instance, higher temperatures generally result in higher residential usage because of increased cooling from air-conditioning. Weather normalization is a process used to adjust energy sales so that they reflect normal weather conditions.

Q. Why is weather normalization important to consider?

A. Relatively low energy sales in the test year because of weather conditions can result in inflated rates and over recovery of the revenue requirement in years when total sales and weather are normal. Test-year revenues are calculated by multiplying test-year billing determinants with current rates. A comparison of test-year revenues with proposed revenue requirements reveals deficits or surpluses under the current rate structure for each customer class. Proposed rates are then calculated, using test-year billing determinants, so that proposed revenues are sufficient to meet the proposed revenue requirement. If test-year billing determinants are low relative to a "normal" year, then a revenue deficit will appear greater than it would have under more typical weather. Proposed rates will be higher to meet the revenue requirement, but actual revenue will be higher than allowed if sales return to normal levels, resulting in a larger increase in proposed rates to meet the proposed revenue requirement. Consider a simplified example where a $1 million revenue requirement is recovered solely via a $/kWh volumetric charge—assuming relatively low test-year energy sales of 10 million kWh would result in a $0.10 per kWh charge; however, energy sales of 11 million kWh in a normal year would result in a lower $0.09 per kWh charge.[1] Therefore, using test-year sales that are relatively low compared to a normal year results in calculating higher proposed rates. Charging higher rates will lead to over recovery of the revenue requirement during years when sales are at a normal level. For instance, furthering the simplified example, the $0.10 per kWh rate multiplied by normal sales of 11 million kWh results in $1.1 million in revenue, an amount above the $1 million revenue requirement.

[1] Current rates and revenues are irrelevant for calculating the proposed rate but can be useful to demonstrate rate increase percentages and revenue deficiencies. For instance, we can continue the simplified example and assume the current rate is $0.08 per kWh. Assuming again relatively low sales of 10 million kWh would result in test-year revenues of $0.8 million dollars, representing a $0.2 million deficit; however, normal sales of 11 kWh would result in revenues of $0.88 million dollars, representing a lower $0.12 million dollar deficit.

Q. Is weather normalization practiced in New Hampshire?

A. It is my understanding that the electric utilities in New Hampshire have not historically weather normalized sales, but that it is a common practice for New Hampshire gas utilities. For instance, the natural gas companies Liberty Utilities (EnergyNorth Natural Gas) Corp. and Northern Utilities, Inc., weather normalize gas sales.[2] Gas sales are weather dependent because space heating is a common use of gas. Electricity sales can be weather dependent because of space heating and air conditioning usage; however, relative to gas, electricity has more end-uses that are not weather dependent. PSNH electricity sales may become more weather sensitive over time if there is increased adoption of heat pumps and air conditioning.

Q. Does PSNH weather normalize their electricity sales?

A. No.

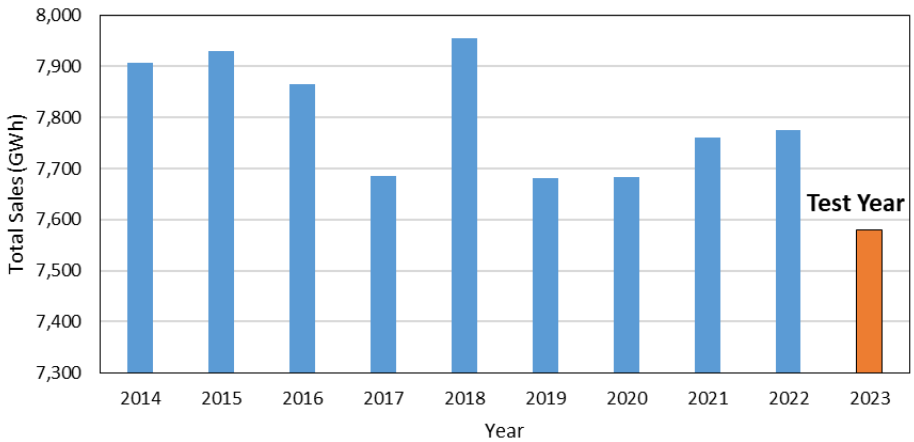
Q. Does PSNH have decreased test-year electricity sales because of weather?

A. Yes. PSNH sales are relatively low during the test year because of weather. Figure 1 contains PSNH's total electricity sales between 2014 and 2023 and illustrates that test-year sales are lower than historical values. For instance, total sales in 2023 are 2.5% less than sales in 2022. Sales declines can be caused by many factors—e.g., weather, economics, price response, energy efficiency, number of customers—which may impact separate customer classes differently. When asked about which factors contributed to the sales decline in the test year, PSNH Witness Davis responded, "Unlike previous years where the COVID-19 pandemic had

[2] For Liberty Utilities, see Direct Testimony of Tyler J. Culbertson and C. Drew Cayton in Docket No. DG 23-067. https://www.puc.nh.gov/Regulatory/Docketbk/2023/23-067/MOTIONS-OBJECTIONS/23-067_2023-07-27_ENGI_TESTIMONY-CULBERTSON-CAYTON-PERM.PDF.
For Northern Utilities, see Prefiled Testimony of Francis X. Wells in Docket No. DG 23-085. https://www.puc.nh.gov/Regulatory/Docketbk/2023/23-085/INITIAL%20FILING%20-%20PETITION/23-085_2023-09-15_NORTHERN_TESTIMONY-WELLS.PDF. The testimony for Northern Utilities details that normal weather is assumed as the average of the actual degree days over the last 15 years (p. 4).

a macro-level impact on energy usage, *weather appears to be a significant factor in decreased sales in 2023 compared with 2022* [emphasis added]. Increased supply prices may also be a significant factor impacting lower 2023 sales during this period."[3]

Figure 1: Total PSNH Electricity Sales, 2014-2023



Source: See Attachment MTC-3, Data Request No. DOE 9-191.

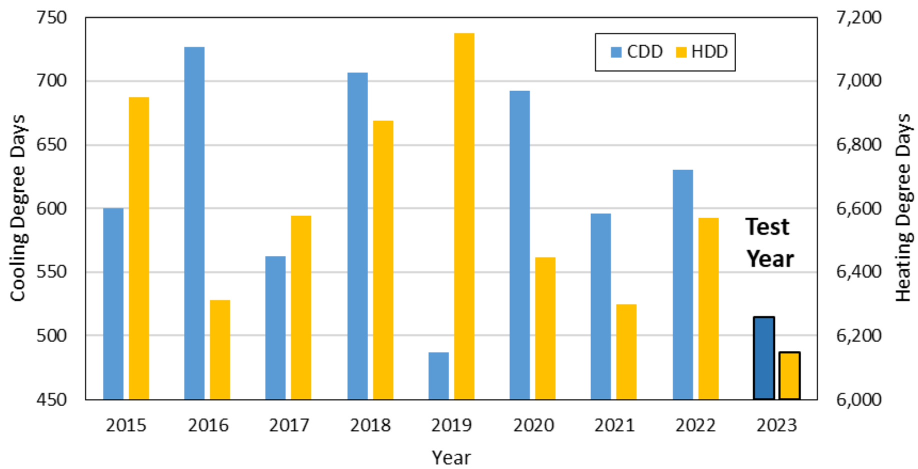
Q. Can you describe PSNH's weather history?

A. Yes. Figure 2 shows weather data in the form of total cooling degree days ("CDDs") and heating degree days ("HDDs") for the years 2015 through the test year 2023.[4] CDDs are intended to reflect the need for cooling-related usage (e.g., air conditioner use) as temperatures increase, while HDDs are intended to reflect the need for space heating in cold weather. Larger CDD and HDD values indicate that the weather is hotter and colder, respectively. Figure 2 demonstrates that weather during the test year was relatively mild compared to other years with lower than usual CDD and HDD values. Hotter weather during

[3] See Attachment MTC-2, Data Request No. DOE 12-233.
[4] Monthly CDDs and HDDs were provided by PSNH in response to a data request, see Attachment DOE 12-234.xlsx. Daily CDDs and HDDS can be added up across days of the calendar month and year. CDD and HDD values are calculated based on a threshold. For instance, a CDD60 value indicates a cooling degree day with a 60-degree threshold and is calculated as CDD60 = Max{0, (MaxT + MinT)/2 – 60}. Similarly, HDD60 indicates a heating degree day with a 60-degree threshold and is calculated as HDD60 = MAX{0, 60 – (MaxT + MinT)/2}.

summer months is associated with higher electricity use because of increased air conditioning loads; on the other hand, colder weather during winter months is associated with higher electricity use because of heating loads. Therefore, it is not surprising that PSNH had lower energy sales during the test year because of the relatively mild summer and winter weather conditions.

Figure 2: PSNH CDD and HDD Weather Pattern



Source: See Attachment MTC-4, Data Request No. DOE 12-234.

Q. Have you investigated the impact of weather normalization on PSNH test-year sales?

A. Yes. PSNH provided monthly usage, customer counts, CDDs, and HDDs since 2015 in responses to data requests.[5] I use this data to weather normalize PSNH's test-year sales, as described further below.

Q. Please describe the approach you used to weather normalize PSNH test-year sales.

A. I estimated weather sensitivity of customer classes using regression analysis. Specifically, a class's monthly use per customer ("UPC") is modeled as a function of weather (CDD and

[5] See Attachment MTC-3, Data Request No. DOE 9-191, for usage data and Attachment MTC-4, Data Request No. DOE 12-234, for weather data.

HDD), month indicators, a year trend, and an indicator for the COVID-19 pandemic.[6] The month indicators and trend variable serve as a proxy for seasonality and economic variables that affect UPC. It is possible that PSNH could refine the model by including its first-hand information regarding customer class specific changes and economic activity. In the models presented here, the same regression specification is estimated separately for Residential (Rates R, R CWH, R UWH, R LCS, R OTOD), General Service (Rates G, G CH, G UWH, G LCS, G Space, G OTOD), Primary General Service (GV), and Large General Service (LG).[7] Model outputs are evaluated to determine goodness of fit and whether the estimated weather coefficients indicate the expected relationship (i.e., hotter weather results in increased usage for residential customers) and are statistically significant.

Weather normalization is appropriate when a customer class's energy consumption is weather sensitive (i.e., customer usage changes in response to weather and is statistically significant). Weather normalized sales are calculated by adjusting observed sales by estimated usage difference between normal and actual weather conditions. Specifically, the weather normalization, given the regression specification described above, would be conducted as follows for each customer class:

$$Q_{Nrml} = Q_{Actl} + Cust \times \{\beta_{CDD}(CDD_{Nrml} - CDD_{Actl}) + \beta_{HDD}(HDD_{Nrml} - HDD_{Actl})\}.$$

Where *Q*, *Cust, CDD,* and *HDD* represent total sales, the number of customers, CDDs, and HDDs, respectively. Subscripts *Nrml* and *Actl* represent normalized and actual values,

[6] The COVID-19 indicator variable covers the period March 2020 through May 2021. Monthly usage data is provided as a billing month (i.e., Jan 1 billing date capture usage from previous month) while CDD and HDD values are provided as calendar months; therefore, CDD and HDD values are converted to approximate billing months by averaging the current and previous month values.

[7] Rate EV-2 is excluded because it has less than one year of data. The outdoor lighting rates, OL and EOL, are not expected to be weather sensitive, and I confirmed this via the described regression analysis.

respectively. Lastly, β represents the estimated weather coefficient for the corresponding CDD and HDD weather variables.[8] I calculated normal weather conditions as the average monthly values over the years provided by PSNH, 2015 through 2023.

Q. What are the results of the process to weather normalize sales?

A. Table 1 provides the results of the weather normalization process. Weather adjusted sales are greater than test-year sales for the Residential, General Service, and Primary General Service classes. Large General Service was not found to be weather sensitive and, as a result, has no difference between actual and weather normalized sales.

Table 1: Actual and Weather Normalized 2023 Test-Year Energy Sales

Rate Class	Actual[1] (GWh)	Weather Normalized (GWh)	% Difference
Residential	3,261	3,357	2.9%
General Service	1,573	1,595	1.4%
Primary General Service	1,587	1,595	0.5%
Large General Service	1,136	1,136	0.0%
Total[2]	**7,580**	**7,705**	**1.6%**

Sources and Notes:
1. See Attachment MTC-3, Data Request No. DOE 9-191.
2. Total includes outdoor lighting and EV rates.

Q. How do your estimates of weather-normalized energy sales impact test-year distribution revenues and the revenue requirement deficiency?

A. Weather adjusted sales can be multiplied by current rates to calculate weather normalized test-year distribution revenues. The revenue requirement deficiency is the difference between the test-year revenue requirement and distribution revenues; therefore, adjustments to distribution revenues have a corresponding impact on the revenue requirement deficiency. Table 2 provides a comparison of actual and weather normalized test-year distribution

[8] Only statistically significant coefficients are used. In other words, the β value is set to zero if the corresponding weather coefficient is not statistically significant.

revenues. The weather normalization of energy sales results in an increase of $6,360,344 to test-year distribution results; therefore, the revenue requirement deficiency would be reduced by this amount if weather normalized sales were implemented.

Table 2: Actual and Weather Normalized 2023 Test-Year Distribution Revenues

Class	Actual[1]	Weather Normalized	Difference
Residential	$ 249,464,535	$ 254,475,372	$ 5,010,837
General Service	96,860,565	98,032,022	1,171,458
Primary General Service[2]	43,309,598	43,487,646	178,049
Large General Service	22,370,087	22,370,087	-
Outdoor Lighting	6,338,708	6,338,708	-
Total	**$ 418,343,492**	**$ 424,703,836**	**$ 6,360,344**

Sources and Notes:
1. Attachment ES-EAD-13, p.2.
2. Includes Rates GV and EV-2.

Q. Do you think that PSNH should weather normalize their electricity sales?

A. Yes. As stated above, reduced electricity sales during the test year due to mild weather results in higher rates and thus over-recovery of the revenue requirement under normal weather conditions. Weather normalized electricity sales should be used when it is believed that weather affects sales in a meaningful way. PSNH has indicated that weather did impact sales during the test year, and I have found that weather normalization of sales would reduce PSNH's revenue requirement deficiency by $6,360,344. Adjustments to test-year sales because of weather is comparable to other adjustments PSNH makes between "per book" and "pro forma" calculations, which are intended to represent values for a normal year going forward.[9] Weather normalization should also be investigated in future rate cases as energy consumption may become more weather sensitive because of increased heat pump

[9] For example, test-year revenues have a pro-forma adjustment to account for rate changes on August 1, 2023. See Attachment ES-REVREQ-1.xlsx, Schedule ES-REVREQ-4, p. 1.

penetration. As more customers adopt heat pumps, we would expect class-level electric usage to be more sensitive to HDDs.[10]

IV. Allocated Cost of Service Study

Q. Did PSNH file an ACOS study?

A. Yes. PSNH's Witness Nieto filed an ACOS study, which was used to allocate the revenue requirement to different customer classes and inform the rate increases.[11]

Q. Please describe the purpose of an ACOS study.

A. An ACOS study allocates total embedded costs to customers classes. The allocation process includes a set of well-established steps and methods that are based on the principle of cost causation. The principle states that customers who cause a cost to be incurred are responsible for the cost.

Q. How is an ACOS study performed?

A. An ACOS study is typically carried out in three main steps: functionalization, classification, and allocation. First, functionalization separates costs into the main functions required to provide electricity to consumers, typically generation, transmission, and distribution, along with general or overhead costs. Second, classification separates costs within each function based on cost causative factors. The recognized factors are total energy consumed (kWh), peak demand (kW), and number of customers. Finally, allocation shares the classified costs across customer classes based on class proportions of observed quantities such as usage, peak demand, and number of customers, "allocators" that represent the cost driver.

---

[10] CDD sensitivity could also be reduced if heat pumps displace less efficient AC usage.
[11] Direct Testimony of Amparo Nieto, Allocated Cost of Service Study.

Q. Does PSNH's ACOS study perform the functionalization, classification, and allocation steps?

A. Yes. The functionalization step is accomplished since the PSNH's ACOS study includes costs associated with just one function: distribution. PSNH's ACOS study classifies costs as either energy, demand, or customer-related and develops allocators to distribute those costs to customer classes.

Q. How does PSNH classify costs in their ACOS study?

A. PSNH uses the FERC Uniform System of Accounts for cost accounting. As noted above, costs for each FERC account are generally classified as either energy-, demand-, customer-related, or a combination. PSNH does not classify any accounts as energy-related because, as mentioned above, the utility adopts the traditional cost classification methodology in which distribution costs do not have an energy causation component. Many accounts are classified as either demand-related or customer-related exclusively. For example, the costs of distribution station equipment (FERC 362) are viewed commonly, and by PSNH, as exclusively demand-related while meter costs (FERC 370) are seen as exclusively customer-related.[12] Other accounts can be identified as either demand- or customer-related. Examples include poles (FERC 364), overhead conductors (FERC 365), underground conduit and conductor (FERC 366 and 367), and line transformers (FERC 368), along with operating and maintenance ("O&M") expenses related to these categories. These accounts contain the bulk of a distribution utility's costs, and thus are difficult to classify as entirely demand- or customer-related only. Therefore, some method must be used to calculate

[12] National Association of Regulatory Utility Commissioners ("NARUC"), *Electric Utility Cost Allocation Manual*, Jan. 1992, Table 6-1, p. 87.

the proportions of those costs that are demand- versus customer-related; PSNH uses a Minimum System Study ("MSS") for this purpose.[13]

Q. What is an MSS?

A. An MSS derives its theoretical basis from the hypothesis that the costs that would be necessary to construct a system to serve loads where each account is represented by a minimal load should be classified as customer related. The difference between total costs and customer-related costs is deemed to be demand-related.

Q. How is an MSS performed?

A. The general process to conduct an MSS is to estimate the current value of the utility's assets in a FERC account and the value of the minimum sized asset in the category. As an example, consider poles (FERC 364), comparing the actual poles in use with a distribution grid consisting exclusively of the utility's minimum-sized pole. The latter is the customer share. The total less the customer share is the demand share.

Q. Is the MSS method well established?

A. Yes, the NARUC Cost Allocation Manual describes the method, and it has been in use for many years.[14]

---

[13] PSNH uses the MSS to classify costs for poles (364), conductors (365, 366, and 367) and transformers (368). MSS classification results are separated by primary vs secondary, single- versus three-phase, and overhead versus underground.

[14] National Association of Regulatory Utility Commissioners ("NARUC"), *Electric Utility Cost Allocation Manual*, Jan. 1992, pp. 90-92.

Q. Are there other cost classification methods?

A. Yes. Other methods for classifying costs as demand- or customer-related include direct classification, the zero-intercept method, and the basic customer method. I provide a brief explanation of each below.

- Direct Classification: Under this method, each line item in the financial accounts – rate base and operating expenses – is classified according to utility staff intuition or reasoning. No attempt is made to determine what the cost causative share (customer, demand, or energy) of an individual account might be. One benefit of this methodology is that it does not require lengthy empirical analysis but relies instead on the experience of utility personnel who deal with the account items regularly.
- Zero-Intercept: The zero-intercept method uses regression analysis to estimate the "zero-load" level of cost based on the costs of units of various sizes. The approach attempts to improve on the theoretical foundations of the minimum system method, avoiding the criticism that the latter still has a demand component in the smallest item. The zero-intercept method extrapolates costs to the zero level of demand instead of using the cost of the smallest unit in the system.
- Basic Customer: This methodology classifies only customer-specific plant costs (related to the service drop, the meter, and possibly other equipment) tied to the customer site as customer-related. The residual costs are classified as a combination of demand- and energy-related, with the energy share being based on load factor, and the demand share constituting the residual. The theory underpinning this split is that costs supporting average load are energy-related and the residual is meant to handle

peak demands. Such sharing is common in generation cost classification and is sometimes extended to transmission in cases where transmission is regarded as an extension of generation.

Q. Is one approach preferable to the others?

A. No. All three methods are in wide use and generally accepted. Utilities typically adopt a method and retain it for multiple rate applications, since methodology changes would possibly result in significant shifts in cost classification and rates. On this basis, PSNH should retain discretion, subject to regulatory approval, in its choice of distribution cost classification methodology.

Q. Are there specific concerns with PSNH's MSS?

A. Yes. PSNH conducted and incorporated an MSS in their previous rate case filing in 2019.[15] PSNH provided an updated MSS for this filing; however, the company did not use updated MSS values for two accounts, poles (FERC 364) and transformers (FERC 368). The utility made this decision because the MSS results "were significantly out of line with those seen in recent historical MS studies, leading to potentially unsupported cost-shifting among customer classes."[16] As a result, PSNH used results from their previous 2019 MSS for these accounts.

Q. How do changes to the MSS affect the ACOS study and proposed rates?

A. Changes to the MSS produce changes in customer and demand cost shares, which affect the allocation of revenue requirements. For example, an increase in the proportion of

[15] Docket No. DE 19-057; Direct testimony of Amparo Nieto, Allocated Cost of Service Study (see Table 1).
[16] See Attachment MTC-5, Data Request No. DOE 9-193. PSNH further describes that "[a] misalignment existed in the updated MS study for these accounts between the year 2023 installed cost of the minimum size as provided by engineering and the total plant population in service today, stated in year 2023 dollars after applying the Handy-Whitman index for this plant type, compared to prior studies. This led to a drastic change in the demand factor that did not appear to be justified."

demand-related costs (and a corresponding decrease in the customer-related proportion) will shift more costs to customer classes that are relatively peak-coincident. PSNH's proposed rate increases are informed by the ACOS study (as well as the MCOS study) so that class revenue increases move in the direction of the ACOS study but are not exact; therefore, adjustments to the MSS are unlikely to be large enough to affect customer class rate increases.[17]

Q. Is it appropriate for PSNH to use results from their previous MSS for specific accounts?

A. Yes. Using the previous MSS results is an appropriate option given that the updated MSS had unreliable results and the previous MSS results were approved in the previous rate case. Nevertheless, I recommend that PSNH investigate either ways to improve the data and analysis of the current methodology or, failing to make an improvement, explore alternative methods for distribution cost classification.

V. <u>Marginal Cost of Service Study</u>

Q. What are marginal costs?

A. Marginal costs reflect the change in the cost of electricity services with a change in the level of service provided. In a perfectly competitive market, goods are priced at their marginal costs which results in the desirable effect of maximizing the amount of consumer and producer welfare and thereby creating economic efficiency.[18] Marginal costs are used in the energy industry for a variety of purposes, including rate design, revenue requirement

[17] Direct Testimony of Edward A. Davis, pp. 8-14.
[18] W. Kip Viscusi, Joseph E. Harrington, Jr., and John M. Vernon. *Economics of Regulation and Antitrust*, Fourth Edition (MIT Press Books, 2005), Chapter 4.

allocation, resource planning, and the evaluation of load response. Marginal costs are calculated separately by the function required to provide electricity to customers (generation, transmission, distribution) and by the driving factor of the cost (demand or capacity, energy, customer).[19] The focus of PSNH's MCOS study is on calculating the marginal capacity cost and marginal customer cost of providing distribution services to customer.

Q. Please provide an overview of PSNH's MCOS study?

A. Witness Neito conducted PSNH's MCOS study.[20] The process included estimating PSNH's demand- and customer-related marginal costs separately for the following items related to providing distribution services:

- Primary distribution costs, including costs of bulk and non-bulk distribution stations, and trunk-line primary feeders;
- Local distribution facilities costs, including transformers and conductors; and
- Customer-related costs, including distribution equipment such as service drops and meters as well as other ongoing customer-related costs required to process meter reads and billing, and other services.[21]

Marginal costs for capital-related expenses are based on historical or budgeted investment costs to calculate a total $/kW amount per investment type.[22] The total $/kW amount is

[19] Each function to provide electricity does not have all cost drivers present. Specifically, generation includes marginal capacity costs (demand-related) and energy costs; transmission includes marginal capacity costs; and distribution includes marginal capacity costs and customer costs.
[20] Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design.
[21] Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design, pp. 6-7.
[22] See Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design. Primary distribution marginal costs are based on budgeted investments for the period 2024-2028 (p. 8). Local distribution marginal costs are based on historical sample of work orders for the period 2021-2023 (pp. 10-11). Meters based on current installed costs by class; service drops based on inflation-adjusted results from previous MCOS study, and O&M expenses based on recent years (see Attachment MCOSS-1, p. 7).

annualized using an economic carrying charge ("ECC") approach which multiplies the investment by a percentage that reflects revenue requirement elements associated with the incremental plant (e.g., depreciation, cost of capital, inflation, average service life).[23] The marginal costs of capital are adjusted, via loading factors, to include marginal costs for general plant, O&M, administrative and general ("A&G"), and material and supplies ("M&S").[24]

The investment costs of primary distribution facilities are based on growth-related capacity expansion projects. A system-wide average marginal cost for primary distribution facilities was calculated by taking into account the share of system peak that was served in capacity expansion areas.[25] PSNH's MCOS study time differentiates these costs by attributing them to hours over of the year using a probability of peak analysis.[26] Other capital-related marginal costs (e.g., local distribution facilities, meters, service drops) are not time-differentiated.

Q. How does PNSH use results from the MCOS study?

A. PSNH uses results from the MCOS study to compare marginal cost allocations of the revenue requirements with those from the ACOS study and to inform rate design. The MCOS study marginal costs are combined with class-level billing determinants to compute marginal cost revenues by customer class. These amounts are adjusted using the equal percentage of marginal costs ("EPMC") method so that the total marginal cost revenue requirement is equivalent to the revenue requirement from the ACOS study. The revenue requirement

[23] Attachment MCOSS-1, p. 8.
[24] Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design, p. 7.
[25] Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design, p. 8.
[26] Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design, p. 10.

allocations can then be compared between the ACOS and MCOS studies; nevertheless, PSNH primarily relies on the ACOS study for setting class revenue targets.[27] The MCOS study is also used to inform rate design by comparing marginal unit costs with proposed rates. For example, Witness Davis and Witness Nieto compare the proposed residential customer charge with the marginal customer cost to support the rate increase.[28] I discuss these elements in more detail below.

VI. Rate Design

Q. What are PSNH's proposed changes to distribution rates?

A. PSNH has proposed to increase rates for each rate class so that the associated proposed revenues are more closely aligned with the revenue requirement allocation created by the ACOS study. While proposed revenues targets move in the direction of the ACOS study results, they don't completely reach that level. PSNH has proposed to introduce three new LED floodlight services.[29] Additionally, PSNH is changing the rate structure for Rate G and Rate GV by eliminating the declining block structure associated with demand and energy charges in accordance with the settlement agreement in Docket No. 19-057.[30]

Q. What are PSNH's proposed revenue increases for each customer class?

A. Table 3 below provides the current and proposed revenue requirements by customer class. PSNH's proposed revenue requirement is also shown as a percentage change and is compared with the percentage increases resulting from the ACOS and MCOS studies. The

[27] Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design, pp. 3-4.
[28] Direct Testimony of Edward A. Davis, p. 8. Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design, p. 21.
[29] Direct Testimony of Edward A. Davis, p. 14.
[30] Direct Testimony of Edward A. Davis, pp. 11-13. Eversource Energy Settlement Agreement on Permanent Distribution Rates, Docket No. 19-057, p. 30.

proposed revenue requirement percentage increase ranges from 36% (OL and EOL) to 65% (R LCS and G LCS) across the different customer classes. Witness Davis describes that proposed rate increases were decided by increasing each rate by the overall 43% increase and subsequently adjusting the percentage increase, upwards or downwards, in the direction of the ACOS study results.[31] For example, the R PL+ TOD rate class is proposed to increase by 47%, which is above the total average increase of 43% so that the rate change is closer aligned with the 60% increase suggested by the ACOS study. On the other hand, the GL PL + TOD rate is proposed to increase by 37%, which is below the total average of 43% so that the increase is closer aligned with the 15% increase suggested by the ACOS study. As shown, the proposed revenue changes do not completely reach the level suggested by the ACOS study but move in that direction, as continuity, gradualism and impact on customers' bills were considered.[32] The percentage changes in revenue requirement from the MCOS study, using the equal percentage of marginal costs ("EPMC") results, are also provided to demonstrate that, relative to the average, proposed percentage changes move in the same direction as the MCOS study for all rates except rates classes R WH and B.[33] I agree with the principles followed by PSNH to move revenues towards the ACOS allocation of costs using gradualism.

[31] Direct Testimony of Edward A. Davis, pp. 8-14.
[32] Direct Testimony of Edward A. Davis, pp. 7-8.
[33] Specifically, Rate R WH is proposed to increase by 52%, above the average, whereas the MCOS study indicates an increase of 40%, below the average. The proposed rate increase for Rate B is 42%, below the average, while the MCOS results indicate an increase of 244%, above the average increase.

Table 3: Rate Increases by Rate Class

	Revenue Requirement ($000)[1]		% Change in Revenue Requirement		
Rate Class	**Current**	**Proposed**	**Proposed[1]**	**ACOS[2]**	**MCOS EPMC[2]**
R PL + TOD	$244,615	$359,134	47%	60%	79%
R LCS	$646	$1,066	65%	204%	341%
R WH	$4,203	$6,393	52%	85%	40%
G PL + TOD	$96,493	$132,219	37%	15%	38%
G SH	$181	$256	41%	25%	-8%
G LCS	$50	$83	65%	256%	101%
G WH	$136	$207	52%	64%	91%
GV	$43,045	$59,908	39%	20%	-82%
LG	$21,077	$30,120	43%	36%	-80%
Rate B	$1,558	$2,217	42%	33%	244%
OL	$4,277	$5,829	36%	3%	-25%
EOL	$2,062	$2,811	36%	-7%	-77%
TOTAL	**$418,343**	**$600,242**	**43%**	**44%**	**44%**

Source and Notes:

1. Attachment ES-EAD-11.
2. Direct Testimony of Witness Nieto, Marginal Cost of Service Study and Rate Design, Table 2.

Q. What has PSNH proposed for rate changes of the distribution rate components?

A. The main components of rates are customer, energy ($/kWh), and demand ($/kW) charges. Table 4 provides a summary of PSNH's proposed rate increases of the customer, energy, and demand rate components, along with separate peak and off-peak percentage increases for the TOD rates.

Table 4: Proposed Billing Determinant Percentage Increases

Rate	Customer	Energy	Demand	Peak Energy	Off-Peak Energy
R	43.5%	48.3%	-	-	-
R WH	43.5%	61.8%	-	-	-
R LCS	65.0%	65.0%	-	-	-
R-OTOD 2	43.5%	44.6%	-	36.1%	49.3%
G	37.0%	37.1%	37.0%	-	-
G SH	40.9%	40.9%	-	-	-
G LCS	65.0%	65.0%	-	-	-
G WH	45.5%	45.5%	-	-	-
G-OTOD	37.0%	37.0%	37.0%	20.7%	130.3%
GV	39.2%	39.1%	39.2%	-	-
LG	42.9%	43.0%	42.9%	39.2%	46.3%
B GV & LG	41.3%	-	42.2%	-	-
OL & EOL	36.3%	-	-	-	-

Source and Notes:

1. Calculations are weighted by billing determinants when more categories exist (e.g., peak, off-peak). Computations done using rates and billing determinants from Attachment ES-EAD-12 and Attachment ES-EAD-15.
2. Lighting Rates OL & EOL are billed per light fixture.
3. Highlighted rows represent rates with a proposed revenue increases above the Company average of 43.5%. Rates highlighted in blue have different percentage increases between rate components whereas rates highlighted in gray have equivalent percentage increases between rate components.

Q. Are the proposed increases to rate components consistent between customer classes?

A. Not entirely. The customer classes R, R WH, and R LCS incorporate a different method for increasing rate components. Additionally, the rate increases for customer class G WH do not align with the proposed revenue requirement increase.

There are six customer classes with proposed revenue increases above the Company total amount of 43%: R, R WH, R LCS, R-OTOD 2, G LCS, and G WH. Of these, three customer classes (R, R WH, R-OTOD 2, highlighted in blue) have a proposed increase to the customer charge of 43.5% (the Company total increase); the additional revenue requirement allocated to these customer classes is proposed to be collected via increases to the energy charge above

43.5%.[34] The other three customer classes (R LCS, G LCS, and G WH, highlighted in gray) have equivalent percentage increases to the customer and energy charges. The remaining customers classes (not highlighted) have proposed rate increases below the Company total amount of 43%. The proposed increases align with the proposed revenue requirement allocations and the percentage increase is equivalent (or similar) between the customer, energy, and demand charges (where applicable).

Q. How do proposed customer rates compare with customer costs from the MCOS study?

A. Table 5 below compares the current and proposed customer charges with customer and local facilities costs from the MCOS study. The "Current/MCOS" and "Proposed/MCOS" columns provide the ratios or current and proposed costs divided by the MCOS results to demonstrate relative differences, values highlight in red indicate that the current or proposed rates are greater than the MCOS study results (i.e., values greater than 100%). Nearly all the proposed customer charges are greater than the marginal customer cost.

[34] Rate G has a proposed revenue requirement increase of 47% (see Table 3); however, the proposed customer and energy charges for this rate result in a slightly lower revenue increase of 46% (see Attachment ES-EAD-15, p.4).

Table 5: PSNH Current and Proposed Customer Charges

Rate	Current	Proposed	MCOS Customer	MCOS Local Facilities	Current / MCOS	Proposed / MCOS
R	$ 13.81	$ 19.81	$ 18.14	$ 24.76	76%	109%
R C WH	$ 4.87	$ 6.99	$ 2.96	$ 2.64	165%	236%
R U WH	$ 4.87	$ 6.99	$ 2.91	$ 2.64	168%	240%
R LCS	$ 6.89	$ 11.36	$ 3.52	$ 8.25	196%	323%
R-OTOD 2	$ 16.50	$ 23.67	$ 25.73	$ 33.01	64%	92%
G P1	$ 16.21	$ 22.21	$ 19.96	$ 56.12	81%	111%
G P3	$ 32.39	$ 44.38	$ 36.90	$ 156.57	88%	120%
G SH	$ 3.24	$ 4.57	$ 3.81	$ 13.40	85%	120%
G LCS P1	$ 4.87	$ 8.04	$ 4.99	$ 15.75	98%	161%
G LCS P3	$ 6.99	$ 11.53	$ 11.62	$ 9.11	60%	99%
G WH	$ 4.87	$ 6.99	$ 4.48	$ 2.31	109%	156%
G-OTOD P1	$ 41.98	$ 57.52	$ 26.04	$ 56.12	161%	221%
G-OTOD P3	$ 60.00	$ 82.22	$ 37.01	$ 156.57	162%	222%
GV	$ 211.21	$ 293.96	$ 89.78	-	235%	327%
LG	$ 660.15	$ 943.40	$ 99.23	-	665%	951%
B GV	$ 372.10	$ 525.63	$ 89.76	-	415%	586%

Source and Notes:

1. Current and proposed customer costs from Attachment ES-EAD-12 and Attachment ES-EAD-15.
2. MCOS results from Direct Testimony of Witness Nieto, Marginal Cost of Service Study and Rate Design, Table 3.
3. P1 and P3 indicate single- and three-phase service, respectively.
4. Highlighted rows represent rates with a proposed revenue increases above the Company average of 43.5%. Rates highlighted in blue have different percentage increases between rate components whereas rates highlighted in gray have equivalent percentage increases between rate components.

Q. Do you recommend any changes to the proposed customer costs?

A. Yes. Recall that the rates R, R WH (C & WH), and R-OTOD 2 had different percentage rate increases between the customer and energy charges, while all other rates had equivalent percentage increases between rate components. Rates R and R WH have proposed customer charges that are greater than the marginal customer costs; of course, using a larger percentage increase for the customer charge would result in larger differences. It seems appropriate that the proposed percentage increases for customer charges were capped at the overall Company increase for Rates R and R WH to reduce differences the marginal customer cost. Rate

R-OTOD 2, however, does not have a proposed customer cost that yet reaches the marginal customer cost amount. Therefore, I recommend that this rate follow the same methodology for all the other rates, which is to have the proposed revenue increase percentage applied equivalently to the customer, energy, and demand (where applicable) rate components. Specifically, I recommend that the proposed customer charge for R-OTOD 2 increase to $24.22, representing a 47% increase from the current customer charge but still below the marginal customer cost of $25.73. Furthermore, the energy charges for R-OTOD 2 should be adjusted so that the proposed revenue increases from the energy components matches 47%.

Q. Does PSNH propose any rate structure changes for their Time-of-Day (TOD) rates?

A. No. PSNH has three rates with prices that vary depending on the time of day: R-OTOD 2, G-OTOD, and LG. PSNH and has decided not to makes changes to their TOD periods in this rate case.[35] Witness Davis has indicated that PSNH will make potential refinements to TOD periods "[a]s billing and metering capabilities increase and more customers show interest in more advanced rate structures."[36] Therefore, PSNH has only proposed to make changes to prices of the TOD rates in this rate case.

Q. Please describe PSNH's TOD periods and proposed changed to rates?

A. Table 6 below provides details for PSNH's TOD rates, including current prices, proposed prices, and prices resulting from the MCOS study. Rate R-OTOD 2 is a residential TOD rate with a six-hour peak period during weekdays, excluding holidays. Rate G-OTOD and LG are general service rates with a thirteen-hour peak period during weekdays, excluding holidays. PSNH has not proposed to change the TOD peak periods. As described above, PSNH

---

[35] The R-OTOD rate class has been closed in accordance with Order No. 26,658, July 15, 2022.
[36] Direct Testimony of Edward A. Davis, p. 7.

proposes to increase rate components by different percentage amounts for R-OTOD 2 and equivalent percentage amounts for G-OTOD and LG (see Table 4 above). I have recommended that Rate R-OTOD 2 also use equivalent percentage increases between the customer and energy charges. For the energy component of the rates, PSNH has proposed to increase prices while maintaining the peak to off-peak price differential for consistency.[37]

Table 6: Details for PSNH TOD Rates

Rate	Category	Peak Hours	Peak ($/kWh)	Off-Peak ($/kWh)	Peak to Off-Peak Price Differential ($/kWh)	Peak to Off-Peak Price Ratio
R-OTOD 2	Current	1 p.m. to 7 p.m.	0.0646	0.0472	0.0174	1.37
	Proposed		0.0878	0.0705	0.0174	1.25
	MCOS		0.0084	0.0004	0.0080	22.46
G-OTOD	Current	7 a.m. to 8 p.m.	0.0535	0.0085	0.0450	6.29
	Proposed		0.0646	0.0196	0.0450	3.30
	MCOS		0.0043	0.0002	0.0041	19.27
LG	Current	7 a.m. to 8 p.m.	0.0056	0.0047	0.0009	1.18
	Proposed		0.0078	0.0069	0.0009	1.12
	MCOS		0.0043	0.0002	0.0041	19.27

Source and Notes:
Peak hours are for weekdays excluding Holidays.
Current and proposed rates source: Attachment EAD-12.xlsx.
MCOS rates source: Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design, Table 3.
MCOS results for G-OTOD are shown for phase-1 customers; phase-3 customers have equivalent price differential and ratio.
MCOS results for LG based on G-OTOD phase 3 customer since MCOS results and TOD periods are equivalent.

Q. Why are TOD peak to off-peak price differentials and price ratios important to consider?

A. TOD peak to off-peak price differentials and ratios provides a measurement of the incentive customers have for shifting usage from peak to off-peak periods. A lower price differential or ratio provides less incentive to shift usage than a larger price differential. The current to proposed peak and off-peak period rates increase while maintaining the same peak to

[37] Direct Testimony of Edward A. Davis, pp. 9, 12-13.

off-peak price differential.[38] The peak to off-peak period price ratios decrease as a result. Specifically, the R-OTOD price ratio decreases from 1.37 to 1.25, the G-OTOD price ratio decreases from 6.29 to 3.30, and the LG price ratio decreases slightly from 1.18 to 1.12.

Q. What should be the basis for price differentials between TOD periods?

A. While evidence suggests that customers have larger TOD peak usage reductions when the peak to off-peak price ratio is larger,[39] the TOD prices should reflect the marginal costs of the system so that customers have appropriate price signals in order to improve economic efficiency. However, price differentials and ratios can also be used to achieve policy goals, such as improving incentives to increase adoption of distributed energy resources.

Q. How should the TOD peak periods be identified?

A. TOD rates should reflect time-varying differences in the marginal cost of generating (where applicable) and delivering electricity. TOD periods should be identified that minimize within-period cost differences and maximize across-period cost differences. The peak period is associated with higher prices to reflect the higher energy and capacity costs incurred during those hours. Similarly, the off-peak period is associated with lower prices to reflect lower costs. TOD periods should be reevaluated as conditions relating to cost drivers change over time. For example, Witness Nieto tested how PV additions in the area may alter the

[38] The peak to off-peak price differential is set according to marginal costs from the 2019 general rate case. Witness Davis explains that "[t]he Company relied on a marginal cost analysis to determine the appropriate peak and off-peak kWh price differentials. In particular, the Company's rate R-OTOD-2 design was informed by the results of the Company's Distribution Marginal Cost of Service ("MCS") study, in particular hourly marginal distribution substation costs, as well as a transmission marginal cost analysis, conducted by the same MCS consultant under Docket No. DE 19-057." See Testimony of Edward A. Davis, Proposed Residential Time-of-Day Rate, Docket No. DE 21-119, p. 6.

[39] Ahmad Faruqui, Sanem Sergici and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," The Electricity Journal, 2017.

TOD periods and found results that reinforced a later peak period of 2 to 8 p.m..[40] Lastly, customer experience should be evaluated when considering TOD periods. For example, TOD periods can be beneficial to customers if the peak period has a short enough duration to be able to avoid the peak by shifting usage from the peak to off-peak period.

Q. Do PSNH's TOD periods reflect cost causation.

A. Not entirely. PSNH has customer- and demand-related costs associated with distribution. The demand-related costs represent capacity costs, which can be attributed to specific hours of the year based on the likelihood of the peak occurring, representing the moment the investment is necessary to meet electricity demanded. PSNH's MCOS study allocates demand related costs to the current peak and off-peak periods for the TOD rates according to a probability of peak ("PoP") analysis.[41] However, results from the PoP analysis do not align well with the current TOD periods. Specifically, the current TOD periods are annual (i.e., there is no time differentiation between seasons), but the PoP analysis suggests that the nearly 100% of peak occurs in June through September. Specifically, Witness Nieto states "[a]bout 90 percent of the annual probability of peak falls in two months, July and August, and the remaining 10 percent falls in the months of June and September."[42] This indicates that a seasonal TOD rate would be more appropriate to reflect the cost causation which occurs from peak capacity-related costs.

[40] Direct Testimony of Amparo Nieto, Marginal Cost of Service Study and Rate Design, p. 22.
[41] Direct Testimony of Amparo Nieto, Marginal Cost of Service and Rate Design, p. 10.
[42] Direct Testimony of Amparo Nieto, Marginal Cost of Service and Rate Design, p. 23.

Q. Are the current TOD periods inefficient?

A. Yes, the current TOD periods are inefficient because they do not provide customers with proper price signals for how costs vary by season. High prices during peak periods should provide a price signal to customers of higher costs during that period. The current TOD peak indicate that prices and costs are high during peak hours for all months of the year; however, the PSNH's PoP analysis suggests that time-differentiated prices should only be higher during the summer months June through September. The current higher peak period prices during non-summer months thus discourages customers from using the grid when costs are relatively low and there is sufficient capacity. Additionally, customer shifts in usage from peak to off-peak periods during the non-summer months does not benefit PSNH's system peak avoidance in summer months.

Q. Do you have any comments regarding the TOD peak period hours?

A. Yes. Results from the PoP analysis and Witness Nieto's testimony support setting the peak period as 2-8 p.m. [redacted] Witness Nieto describes in her testimony that "there is significantly lower probability of peak at any afternoon hours prior to 2 pm and increased probability of peak from 6 pm to 8 pm, compared to the findings of my TOU analysis in the prior MCOS (2019 GRC) which suggests that a modification of TOU periods would increase cost-reflectiveness of the peak distribution rate."[44] She later mentions that "[i]t will also be important to add the weekday

---

43 [redacted]

44 Direct Testimony of Amparo Nieto, Marginal Cost of Service and Rate Design, p. 22.

hour 7 pm to 8 pm as more customers enroll in the TOU rate."[45] Lastly, Witness Nieto also suggests that the 2-8 pm period would be more conducive to increased penetration of PVs but indicates that it isn't imperative to make a change now given the low number of customers on the residential TOD rate.[46] Based on these findings, I recommend changing the peak period to 2-8 p.m.

Q. What are the benefits of your recommended changes to the TOD periods?

A. Changing the TOD periods has three major benefits. First, the TOD rates would become more price efficient, in other words, they would provide customers with prices signals that reflect time differentiation of the PSNH's costs. This allows customers to incorporate accurate pricing information in their electricity consumption decisions. As well, the pricing will not discourage energy consumption in non-summer months when utility delivery costs are low and system capacity is sufficient. Second, the recommended seasonal TOD period would result in higher peak to off-peak price differentials and ratios due to concentrating more marginal costs in fewer hours in the year. This would allow PSNH to provide customers a larger incentive to shift usage from the peak period to the off-peak period during months when the shift is needed most. Third, the recommended TOD period of 2-8 p.m. would be more conducive to increased PV penetration in the future, as suggested by Witness Nieto.[47]

---

[45] Direct Testimony of Amparo Nieto, Marginal Cost of Service and Rate Design, p. 22.
[46] Direct Testimony of Amparo Nieto, Marginal Cost of Service and Rate Design, pp. 22-23.
[47] Direct Testimony of Amparo Nieto, Marginal Cost of Service and Rate Design, pp. 22-23.

Q. Should PSNH incorporate the recommended changes to the TOD period in this rate case?

A. Yes. Changing the TOD periods now is useful given the benefits mentions. As well, the change is prudent considering PSNH is proposing to "stay-out" of a rate case for at least four years as part of their proposed PBR plan.[48]

Q. Should the TOD periods be different between the rates R-OTOD 2, G-OTOD, and LG?

A. No. I provide below a few potential reasons TOD periods may be different between rates; however, I am unaware of any sufficient reason that PSNH maintain different TOD periods for its rates. First, as discussed, TOD periods should reflect underlying marginal costs; therefore, different TOD periods may be appropriate if the underlying marginal costs differ between customer classes. Second, a utility may provide different TOD options in response to customer needs and/or preferences.[49] Third, multiple TOD periods can be a result of the vintage, as it can be challenging to modify or change a TOD rate because of continuity and bill impact concerns. Finally, it is my understanding that there can be a cost to reprogram meters to record usage during different TOD periods and these costs may be a factor in updating the TOD periods. I am unaware if these reasons, or others, are adequate to maintain different TOD periods between the rates R-OTOD 2, G-OTOD, and LG. Therefore, I recommend that the TOD periods be equivalent for each TOD rate.

Q. Can you summarize your recommendations regarding PSNH's rate design?

A. I recommend the following changes:

---

[48] Direct Testimony of Douglas W. Foley, Robert S. Coates, Jr., and Douglas P. Horton, Case Overview, p. 39.

[49] For example, Pacific Gas & Electric offers multiple TOU rates, including an option with multiple periods (peak, part-peak, off-peak) to accommodate electric vehicle customers (see Schedule EV2).

- For Rate R-OTOD 2, increase the proposed customer charge from $23.67 to $24.22.
- A seasonal TOD period with the peak period occurring only during months June through September (or alternatively July through August).
- A TOD peak period of 2 to 8 p.m. weekdays, excluding holidays.
- Apply the recommended TOD period changes to all TOD rates (R-OTOD2, G-OTOD, LG).
- Update the peak and off-peak prices for TOD rates (R-OTOD2, G-OTOD, LG) based on MCOS study results that allocate time-differentiated marginal costs to the recommended TOD periods using the PoP analysis.

VII. Revenue Decoupling

Q. Has PSNH provided a Revenue Decoupling Mechanism ("RDM") proposal?

A. PSNH has submitted a RDM framework as part of the settlement agreement approved by the Commission in Docket No. DE 19-057; however, PSNH is not proposing to implement the RDM.[50]

Q. Please describe PSNH's RDM framework.

A. The RDM allows PSNH to adjust customer rates based on the differences between actual and allowed revenues in a decoupling year. The amount of allowed revenue is based on the approved revenue requirement. The difference between actual and allowed revenues is divided by total billed sales (kWh) during the decoupling year to calculate a $/kWh Revenue Decoupling Adjustment Factor ("RDAF"), which is then applied to all customer usage in the subsequent year. Revenue deficiencies (i.e., when actual revenue is less than allowed

[50] Direct Testimony of Witness Davis. June 11, 2024, pp. 16-17.

revenue) or surpluses (i.e., when actual revenue greater than allowed revenue) are aggregated across months and customer classes to calculate an annual total adjustment. A revenue deficit would result in an RDM surcharge while a revenue surplus would result in an RDM credit to customers. Witness Davis indicates that the allowed distribution revenue requirement depends on whether RDM is implemented with or without their proposed PBR framework.[51] If the RDM is implemented with PBR, the allowed revenue would be adjusted each year based on the PBR formula, including the "K-Bar" adjustment. If the RDM is implemented without PBR, the allowed revenue would be adjusted each year based on a methodology authorized by the Commission.

Q. Do you recommend that PSNH implement their RDM?

A. No. As mentioned, PSNH has proposed an RDM framework to comply with the settlement agreement in Docket No. DE 19-057 but is not requesting to implement the RDM. RDMs are generally viewed as a tool to remove a utility's disincentive to promote conservation while simultaneously helping the utility avoid under-recovery of fixed costs. I have not seen these issues discussed by PSNH or the DOE in connection to RDM and therefore do not see any reason to implement RDM if neither party is advocating for it. Nevertheless, if the Commission decides that an RDM is necessary, I provide recommendations regarding PSNH's proposed RDM framework.

Q. Do you recommend that PSNH include any soft or hard cap in its RDM?

A. An RDM cap restricts the size of the allowed rate adjustment in each year. A "soft" cap means the utility can retain deferral amounts above or below the cap for future recovery or

[51] Direct Testimony of Witness Davis, June 11, 2022, p 18.

refund.[52] In contrast, under a "hard" cap the utility would not be able to recover or refund amounts above or below the cap. PSNH has not suggested a soft or hard cap. The soft cap has the benefit over a hard cap by preserving incentive properties, that is, when hard caps are binding, the utility's disincentive to promote conservation still exists. Other New Hampshire utilities, Liberty Utilities Corp. ("Liberty") and Unitil Energy Systems ("Unitil"), incorporate a 3% soft cap, which is applied to both over and under recoveries.[53] Unitil in Massachusetts uses a 1.5% soft cap for under recoveries but over recoveries are credited in full.[54] I recommend that PSNH's RDAF have a 3% soft cap for under recoveries but that over recoveries be applied in full.[55]

Q. Do you recommend that PSNH use forecast or decoupling-year sales when calculating the RDAF?

A. The RDAF is calculated as the revenue deficiency/surplus divided by total sales, which can represent total sales during the decoupling year or "alternatively be adjusted to match forecast billed sales of the period in which the factor is designed to be in effect."[56] The RDAF will be applied to sales in the year subsequent to the decoupling year, therefore, it is useful to estimate expected sales during that period. If estimated expected sales are lower than those that occur in the year when the RDAF is in effect, then the RDAF will not fully recover the allowed revenue deficiency or fully return the allowed revenue surplus. Similarly, if expected sales are higher than those that occur, then the RDAF will over recover the

[52] Interest can be applied to deferred amounts.
[53] For Liberty, see Settlement Agreement in Docket No. DE 23-039. For Unitil, see Schedule RDAC.
[54] See Fitchburg Gas and Electric Light Company Schedule RDAC
[55] Unitil in Massachuesstes. Uses a 1.5% soft cap for under recovieries only but over recoveries are credited in full. See Fitchburg Gas and Electric Light Company Schedule RDAC
[56] Direct Testimony of Witness Edward A. Davis, p. 18.

allowed revenue deficiency or over credit the allowed revenue surplus. While decoupling-year sales may serve as a reasonable proxy for expected sales, I recommend using forecasted billed sales.[57]

Q. Does the proposed RDM allow for cross-subsidies between customer classes?

A. Yes. The RDAF is calculated using total revenue deficiencies or surpluses and is the same for all customers. Therefore, a customer class that has a revenue surplus will still have a RDAF surcharge if the aggregate deferral across all classes reflects a shortfall. This results in customer classes with revenue surpluses cross subsidizing customer classes with revenue shortfalls when total revenues are deficient. Some customers are better off while others are worse off because of the cross-subsidy.

Q. Do you have recommendations to reduce potential for cross-subsidies due to the RDM?

A. Yes. I recommend that PSNH's RDM be modified so that the RDAF is calculated by pooling similar customer classes together as opposed to being calculated at the aggregate level. Specifically, I recommend calculation of separate RDAF values for the following groups:

- Residential: R, R CWH, R UWH, R LCS, R OTOD2
- General Service: G, G CH, G UWH, G LCS, G Space, G OTOD, GV, EV-2

These groupings would reduce inter-class cross-subsidies while minimizing the potential for volatile RDAF values that may occur when relatively few customers are included in a decoupling group. I further recommend that rates LG, OL, and EOL not be decoupled.

[57] Over and under-recovery of the initial true up can also be tracked. Any residual amount may be placed back in the deferral account.

Q. Why do you recommend that rates LG, OL, and EOL not be decoupled?

A. Decoupling may not function well when the deferral is calculated for a group in which a few customers account for a significant share of group-level usage because the usage of a few customers can have a significant effect on the group's deferral. Rate LG has fewer than 130 customers during the test year.[58] Typical bill impacts for Rate LG indicates a range of billed usage from 300 MWh to 2,100 MWh.[59] There is no similarly sized rate class that can be combined with Rate LG to reduce the potential for the largest customers in the class to have an outsized effect on the deferral. The outdoor lighting rates OL and EOL do not need to participate in a RDM because billed sales are predictable for these classes and do not fluctuate between years.

Q. How does the proposed PBR interact with the RDM?

A. As mentioned, if the PBR and RDM proposals are both implemented, then the allowed revenue amount will increase based on the PBR formula, including any "K-bar" adjustments. Implementing PBR with the proposed RDM is known as a "revenue cap". Alternatively, implementing PBR without the proposed RDM is known as "price cap". Therefore, PBR and RDM are not inconsistent with each other and can both be implemented. For further discussion regarding the interaction of PBR with revenue decoupling, please see the direct testimony of Nicholas A. Crowley and Daniel McLeod.

[58] See Attachment MTC-3, Data Request No. DOE 9-191.
[59] Attachment ES-EAD-14, p. 23. Additionally, PSNH provides customer counts for different usage ranges which confirms that the high usage ranges contain low customer counts for Rate LG (see Attachment MTC-7, Data Request No. DOE 12-236).

Q. Can an RDM be implemented in lieu of weather normalization?

A. Yes. As discussed above, I have recommended weather normalization of test-year billing determinants to prevent rates from being set too high, which would result in utility over-recovery if weather reverted to normal conditions. An RDM could be used in lieu of weather normalization to prevent over-recovery of the revenue requirement. That is, if rates are set too high due to mild test-year weather, under the RDM any resulting over-recovery of revenues would be returned to customers via the RDAF.

Q. Please summarize your recommendations regarding the RDM?

A. I do not recommend that the proposed RDM be implemented considering neither PSNH nor the DOE is advocating for it. However, if it is determined that a RDM should be implemented, then I recommend the following changes to PSNH's RDM:

- Soft cap of 3% for under recoveries but over-recoveries be returned in full;
- Use forecasted billed sales when calculating the RDAF; and
- Reduce cross-subsidies by calculating a separate RDAF for residential (R, R CWH, R UWH, R LCS, R OTOD2) and general service classes (G, G CH, G UWH, G LCS, G Space, G OTOD, GV, EV-2) as well as not decouple the LG, OL, and EOL rates.

VIII. Summary of Recommendations and Conclusion

Q. Please summarize your recommendations.

A. My recommendations are:

- PSNH should adjust billed sales during the test year using weather normalization.
- For classification of demand- and customer-related costs in the ACOS study, PSNH should investigate ways to improve the data and analysis of the current MSS

methodology or, failing to make an improvement, explore alternative methods for distribution cost classification.

- For Rate R-OTOD 2, PSNH should increase the proposed customer charge from $23.67 to $24.22.
- PSNH should make the following adjustments to TOD periods and prices:
  - A seasonal TOD period with the peak period occurring only during months June through September (or alternatively July through August).
  - A TOD peak period of 2 to 8 p.m. weekdays, excluding holidays.
  - Apply the recommended TOD period changes to all TOD rates (R-OTOD2, G-OTOD, LG).
  - Update the peak and off-peak prices for TOD rates (R-OTOD2, G-OTOD, LG) using MCOS study results that allocate time-differentiated marginal costs to the recommended TOD periods with the PoP analysis.
- An RDM should not be implemented by PSNH; however, if an RDM is to be implemented, then PSNH's proposed RDM should be modified as follows:
  - Include a soft 3% for under recoveries but over recoveries be applied in full;
  - Use forecasted billed sales when calculating the RDAF; and
  - Reduce cross-subsidies by calculating a separate RDAF for residential (R, R CWH, R UWH, R LCS, R OTOD2) and general service classes (G, G CH, G UWH, G LCS, G Space, G OTOD, GV, EV-2) as well as not decouple the LG, OL, and EOL rates.

Q. Does this conclude your testimony?

A. Yes.