STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 19-057

REQUEST FOR PERMANENT RATES

REBUTTAL TESTIMONY OF AMPARO NIETO

Cost of Service Studies and Rate Design

On behalf of the Public Service Company of New Hampshire

d/b/a Eversource Energy

March 3, 2020

Table of Contents

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I. INTRODUCTION

Q. Please state your names and current position.

A. My name is Amparo Nieto and I am a Senior Vice President at Economists Incorporated.

Q. Have you previously testified in this proceeding?

A. Yes. I prepared two direct testimonies on behalf of Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH" or the "Company"). In one, I discussed the Company's Allocated Cost of Service Study ("ACOS" or "ACOS Study"). In the other, I described the Marginal Cost of Service Study ("MCOSS" or "MCOS Study") I conducted on behalf of PSNH and discussed the best practice methods for setting class revenue targets, using MCOSS results for rate design decisions. A statement of my qualifications was attached to my prepared direct testimony.

Q. What is the purpose of your rebuttal testimony?

A. I provide rebuttal position on issues pertaining to the embedded and marginal cost of service studies, class revenue allocation and rate design as raised by Staff and OCA witnesses in their filed direct testimonies. The witnesses include Ron Nelson, on behalf of the Office of Consumer Advocate ("OCA"), witness Agustin Ros, representing Staff, and witness Sanem Sergici, representing Staff.

Q. How is your testimony organized?

A. My rebuttal testimony is organized as follows.

- In Section II, I respond to the findings of OCA witnesses on the ACOS study.
- In Section III, I respond to the findings of both OCA and Staff witnesses on the MCOSS.
- In Section IV, I respond to the comments of OCA and Staff witnesses on the Company's proposed class revenue allocation and rate increases by class.
- In Section V, I discuss witnesses' key comments on the Company's proposed rate designs.
- In Section VI, I summarize my recommendations to the Commission.

II. ALLOCATED COST OF SERVICE STUDY

Q. What are the main comments of Mr. Nelson with regard to the ACOS study methods?

A. Witness Nelson's main comments on the ACOS study mostly revolve around methods to classify plant as either customer or demand costs. He specifically directs attention to the minimum distribution system (MDS) analysis that the Company developed to produce customer and demand classification factors for FERC accounts 364 through 368, which include poles, primary voltage lines, line transformers, and secondary voltage conductors. In his testimony, Mr. Nelson maintains that certain elements of the Company's MDS study do not adhere to the guidelines of the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual. Interestingly, after discussing the details of the Company's MDS approach, he ultimately asserts that an MDS study is not suitable for classification of any distribution plant accounts and recommends not to rely on any MDS study. In his view, no portion of distribution lines or transformers is customer related. Instead the supports a method called the "Basic Customer" approach, under which all distribution plant, except for meter and service laterals, is treated as demand related.

Q. **What aspects of the MDS approach does Mr. Nelson have a concern with?**

A. Mr. Nelson takes issue with a number of implementation aspects of the MDS study. The most significant criticism has to do with the classification of primary lines (included in accounts 365 through 367), arguing that all primary lines should be considered 100 percent demand-related, and not included in the MDS study. Currently, the MDS classifies 64 percent of primary lines costs as demand-related (on average across the three accounts). He also mentions a few other concerns which would have less of an impact on the total class allocated distribution costs. These include the Company's use of trended installed cost as opposed to current average book cost, choosing minimum size equipment that is consistent with that currently being installed and using separate classification factors for single phase vs. multi-phase lines in (Acc. 366 & 367).

Q. Does the MDS study intend to capture the more fixed nature of FERC accounts 364 through 368, which is different from the demand served by substations or upstream feeders?

A. I believe so. The MDS relies on a hypothetical scenario of either "minimum" or no load. An MDS attempts to identify the minimum system that the Company would have installed to provide service and appropriate voltage to a customer, at the point at which the customer connects to the distribution system. Thus, the minimum system can be interpreted to represent the Company's "readiness" to serve a customer, and in particular presumes that all customers would at least need that minimum equipment, within each property grouping, irrespective of the actual customer's peak demand requirements. The minimum costs incurred to provide a customer with such access do not vary with load changes and therefore is classified as customer-related cost. The portion of the total costs in each account, is assumed to provide capacity to meet the full customers' peak load requirements beyond minimum requirements, and it is classified as a demand-related in the MDS study.

Q. Do you agree with Mr. Nelson's characterization of PSNH's MDS study not being compliant with NARUC?

A. No. Based on my review of the MDS study conducted by the Company, I find that the various steps undertaken by the Company are compliant with the framework outlined by NARUC. I also confirmed that the Company relied on the most detailed plant account inventory information available as well as the engineers' views on the minimum plant size currently being installed. I also find that the MDS is reasonable as an embedded cost method and not inferior to approaches that classify all transformer and wires as either 100% customer related or 100% demand-related. While all distribution plant is unmistakably driven by the need to serve demand, the MDS allows to introduce the notion of per-customer transformer capacity requirement and customer-specific driven conductor installations. The minimum system study, by virtue of considering each class's test year customer numbers as an allocator, acknowledges that decisions on transformer sizes are in large part a function of the individual customers to be served from it. It also implicitly acknowledges that the nature of the demand driving the investment in these types of plant is not precisely captured by neither test-year class NCP factors nor test year class' sum of individual maximum customer demands.

Q. Do you find contradictions in Mr. Nelson's concerns over the MDS study and his discussion of the classification of distribution plant?

A. Yes. During Mr. Nelson's discussion of which elements of the Company's MDS study would appear not to strictly follow NARUC's manual, he advocates for modifications that clearly depart from NARUC's guidelines. For example, in his testimony he argues that the primary distribution lines should have been excluded from the MDS study. Regardless of whether this is the right approach or not, his proposal in principle does not align with the NARUC's Manual.

Q. Did you make any modifications to the MDS study developed by the Company?

A. I reviewed the Company's MDS analysis and used the resulting customer and demand classification factors as inputs for the ACOS study. The only modification I made to the results was with regard to FERC accounts 366 and 367. I separated out the classification factors between single and three-phase lines, to take advantage of the detailed plant records by phase for those two accounts. This was to acknowledge that not all customer classes use the single-phase primary lines.

Q. Is it your opinion that the NARUC Manual grants discretion regarding classification of distribution plant?

A. Yes, I believe that the NARUC's manual is not intended to be prescriptive. My understanding is that it was designed to serve as a guide to utility analysts with respect to how an allocated cost of service study should be conducted. In practice, utilities employ their own interpretation of these guidelines, and may adopt variations of the specific steps presented in the NARUC manual within the overall conceptual framework. In many cases, the utilities' methodological choices are constrained by the level of detail in their accounting records, plant inventory and metering types in place. Clearly though, the NARUC Manual does not endorse an allocation of plant in accounts 364 to 368 strictly on the basis of demand, which is the method that Mr. Nelson recommends. Classification of poles, primary feeders, line transformers and secondary wires as both demand and customer-related is consistent with NARUC's cost allocation Manual. It is also widespread practice in the context of ACOS studies. I do not think that a utility needs to limit itself to what NARUC recommends, since it is not a normative but a guiding manual. However, I find shortcomings in the Basic Customer approach that have to do with its implementation approach.

Q. What role does the Company's MSD play in improving cost causation as opposed to the method recommended by Mr. Nelson?

A. One merit of the minimum system study over the Basis Customer approach, is that it generally does a better job at recognizing the impact of lumpiness intrinsic to these facilities. For example, investment in line transformer is lumpy and generally cannot be performed in small capacity additions that perfectly match each incremental load requirement. The economies of scale inherent to transformer sizes mean that a bigger transformer has generally a lower per-kW of capacity cost than a smaller transformer. This is particularly relevant in PSNH's service territory where the transformers and local wires are not shared by many customers. The standardized transformers available may mean that a given size transformer more than sufficiently meets the customers' expected long-term maximum demands.

Q. Please explain in more detail the role of number of customers connected in influencing the specific cost driver for transformers and wires.

A. Thus, the level of reliability provided by a transformer is not only a function of the actual load requirement expectations but also the fact that there may only be one or two customers connected to a relative large standard transformer but the next transformer size down would not be large enough to accommodate both their demands. Thus, it is not uncommon for these facilities to have near-term excess or unused transformer capacity, given the economies of scale inherent to these facilities. In other words, due to the lumpiness of investment, the actual customer peak load requirements may be lower than the average transformer kVA per customer for either one or several single residential homes or small commercial customers. There may be situations where both customers have the same maximum demand, but one is served from a more heavily shared transformer than the other. In this scenario, the cost per kW of maximum demand is different for each customer, even if the average cost per kVA of transformer rating is the same for both transformers.

Q. Is there another reason why a transformer or local conductor may have near-term capacity?

A. Yes. Generally, distribution planners attempt to locate transformers to optimize utilization by the group of customers requesting connection, which will also include secondary lines, and for general service customers, installation of primary lines. Once the designer has optimized the transformer location, the decision of its kVA rating will depend upon both the number and type of customers that will be expected to be attached to the transformer, but these standards are intended to assure limited maintenance and replacement of distribution transformers, thus, the planner needs to consider a kVA rating that will sufficiently meet the expected total maximum demand of each type customer connected over its service life. The main implication is that taking simply the cost of Accounts 368 and spreading it to all customers entirely on the basis of their test-year maximum demands or, as used in the PSNH study, customer demands coincident with their respective class peak hour (class NCP), may not produce a precise allocation.

Q. Do you consider that there is room for improvement in the Company's method to classify distribution plant?

A. In the case of an MDS analysis, the minimum system clearly has an inherent ability to serve load, which is often pointed out as the main weakness of the approach since there is potentially some double counting of demand in the allocator. A zero-intercept approach is sometimes considered as an alternative method that might provide a better relationship between cost and size, however in practice it does not necessarily provide a more realistic classification result. In fact, in some instances it may lead to non-intuitive outcomes, such as negative customer costs. This only points out how the ACOS methods are an attempt to follow cost causation but are limited by the accounting and class customer requirements information available. It is generally challenging to work with accounting records in a way that provides the precise relative cost differentials among customer classes. One example is transformers. As discussed earlier there are step changes in installed cost per kW of transformer capacity when the transformer size changes, and there are differences in installed cost per kW of customer's maximum demand, depending on relative customer density (urban, rural) and other characteristics that may differ by customer class, such as single versus three-phase connections which also lead to different costs. This underscores that class customer numbers alone or demand records alone may not be by itself the best minimum system cost driver to spread costs to customer classes without a proper weighting factor. This is in my view, the main limitation of the MDS approach, but it also affects and limits the Basic Customer approach.

Q. How would the class weights be developed for a more precise allocation of distribution plant?

A. Appropriate class weighted customer allocators would look at customer density or relative sharing of facilities. For residential customers, the transformer selection needs to cover the peak design demand presumed for the specific category of customers to be served. The categories typically vary between non-electric heat loads and electric heat winter load, stand-alone home versus multi-unit buildings. For transformers serving mainly commercial or industrial loads, the transformer size is determined to meet the maximum expected load of each individual customer as shown on recent history (spanning more than a year) or a standard commercial load if it is a new customer. Weights for demand-related cost allocations would account for the relative per-kVA cost differentials due to economies of scale built into the standard transformer size usually serving each category type. Again, because ACOS rely on accounting data and is a top down approach, it is problematic finding the proper class weighting factors. These are more easily developed in the context of a distribution facilities cost analysis undertaken as part of the MCOSS. A marginal cost analysis appropriately considers the relative variation in typical connection cost by class because it takes into account typical kW of transformer capacity assigned to the average customer in the class.

Q. Is the use of the MDS approach widely adopted for classifying distribution plant?

A. Yes. The concept of a minimum system and associated analysis has been extensively adopted in utility ACOS studies across the US and Canada, along with methods that use regression analyses to find the minimum or 'zero load' cost as the basis for classification. I have also observed utilities in the US and Canada that use an arbitrary and equal split between demand and customer-related costs, typically for transformer and secondary conductor, but in some cases for primary lines as well. However, based on my review of ACOS studies across the country, the most prevalent way to classify distribution plant accounts 364 through 368 is by either using the minimum system study, the zero-intercept approach, or a hybrid. The hybrid approach may include the two methods but differentiating depending on the plant account. Finally, some studies that use the minimum system study apply it only to transformer and secondary wires and poles, and not to primary. Examples of U.S. utilities where MDS is used in a cost of service study include Alabama Power (AL), Georgia Power Company (GA), Central Hudson Electric & Gas (NY), Central Maine Power (ME), Choctawhatchee Electric Cooperative (FL), Tampa Electric (FL), Connecticut Light & Power (CT), Duke Energy Progress (NC), Gulf Power

(FL), Jackson County REMC (IN), Kentucky Utilities (KY), LG&E (KY), Madison Gas & Electric (WI), Mississippi Power (MS), Northern States Power (MN), Rochester Gas & Electric (NY), and Carolina Power & Light (NC). In Canada, the use of an MDS study is also common, and examples include ATCO, New Brunswick Power Corporation, Newfoundland Power, Hydro One and Hydro Quebec.

Q. Do you agree with Mr. Nelson's view regarding the need to classification of primary lines?

A. Only partially. I have seen studies such as the examples mentioned by Mr. Nelson, which exclude primary lines from the minimum distribution system, but a proper classification of primary lines, would require making a distinction according to the type of feeder and the demand that it serves, so as to only exclude the primary lines serve highly diversified loads. To the extent that the line is local to the customer premises, the planning and sizing of these facilities will be driven by the individual customers connected to them, as opposed to station or upstream primary coincident peak. The Company's trunk-line primary feeders tend to have a voltage of 46 kV or 34.5 kV and are generally expected to serve diversified loads. Thus, to reflect cost causation, ideally these feeders should be separately classified independently of the rest of primary feeders and be treated as purely demand-related. The allocation could be either distribution system coincident peak load (as a proxy for the substation coincident peaks that drive the investment), or a hybrid of coincident peak and class non-coincident peak, equivalent to the allocator employed for station plant (Accounts 360-362), although they are comparable with the exception of the smaller classes. The remaining overhead primary lines are more likely to be primary taps serving a small group of customers and classifying them via the MDS study is thus reasonable as opposed to consider them entirely demand-related. Making a distinction for purposes of separating the classification of primary lines with any level of precision would require that the Company's accounting records differentiate by specific voltage, other than the broader "primary" or "secondary" categories. From my experience, when a utility employs an MDS it tends to apply to all wires in addition to the transformer. The reason is likely the limitations in the accounting data since many utilities do not keep records of distribution plant cost by voltage level. This is also the case of PSNH. An approximation based on general circuit mileage information might be misleading since they would not be tied to accounting records by voltage level. NARUC considered that the minimum system and minimum intercept approaches were applicable to both primary and secondary lines without any further sub-functionalization, presumably anticipating this constraint in the available accounting information.

Q. Is the Basic Customer approach as proposed by OCA's witness appropriate or more cost reflective than the MDS study?

A. I do not believe that the Basic Customer approach, which excludes both lines and transformer costs from the customer-related costs, works well in the context of an embedded cost of service study. First, as I mention earlier, all customers, except those who own their own transformer, need a minimum equipment that provides interconnection and a minimum level of voltage conversion irrespective of the amount of actual demand. That element is lost in the Basic Customer approach. Second, if the transformer and primary or secondary lines were to be consider fully demand-related, it would be necessary to make sure that the demand allocator takes into account the nature of the cost driver of transformer and local secondary and primary lines, which is not actual on-going customer demands. NCP demand is the highest hourly demand occurring for each rate group during the entire test period. The class NCP allocator is generally non-contentious as an allocator for transformers since it more closely approximates how the Company plans and operates the facilities local to the customer. Customer peak loads in these facilities have much less diversity than they do at the upper voltage levels of the system. The NCP allocator nevertheless has limitations in that it does not fully reflect the characteristics of transformer peak loading at the primary and secondary distribution levels. This is because it is often the case that one transformer may serve more than one class. In addition, PSNH's local delivery system may peak at different times, depending on the mix of customers in each area. Class NCP does not measure the potential maximum demand that a given transformer is expected to have – equivalent to the concept of contract back up capacity for all customers with cogeneration. I believe that class NCP would no longer be the proper allocator as it would not reflect cost causation if the entire plant in these accounts were to be considered demand-related. If the full plant were to be considered 'demand-related', there might be some merit in considering the sum of individual customer maximum demands, but even then, the allocator would fail to recognize any diversity in the specific peak load of the transformer. Mr. Nelson's testimony presents a summary of allocated costs using the Basic Customer approach, relying on information I prepared as part of a response to a data request from OCA which requested all costs to be allocated on the basis of demand. In that scenario the class allocations for accounts 364 to 368 used class NCP. Not only does the Basic Customer approach have little industry or regulatory precedent in an ACOS context, but it also creates the risk of using the wrong cost driver for these facilities. There is a reason why NARUC considers transformers and lines to be partly customer-related in its Manual, and it is the lack of correlation with standard measures of demand, such as class NCP. By assigning a share of the costs to customer numbers, the problem of relying on class NCP while potentially still imperfectly, is somewhat ameliorated.

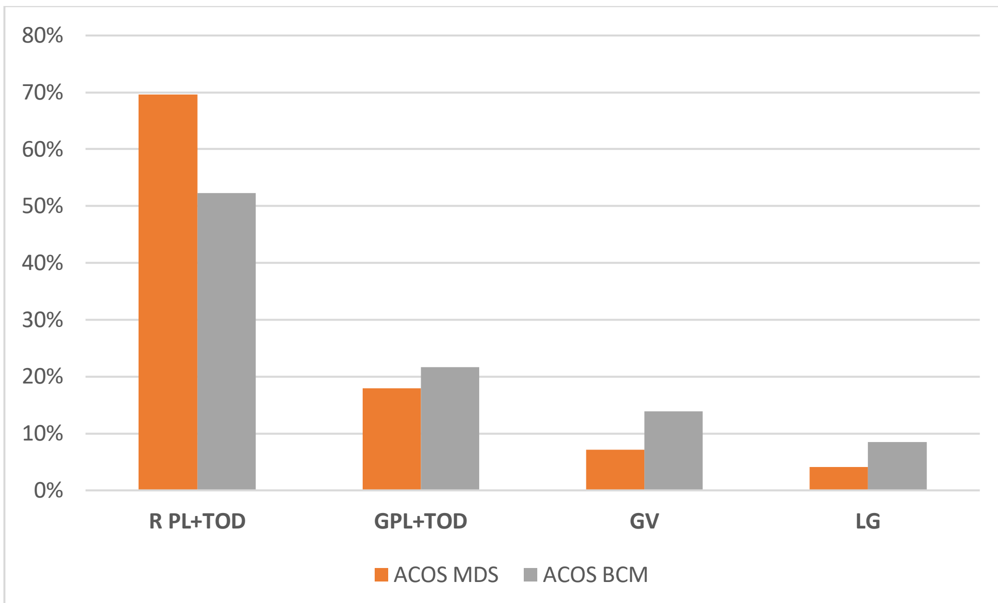
Q. Is Mr. Nelson's claim that distribution transformers and other distribution facilities local to the customer are demand-related supported by economic literature?

A. Mr. Nelson argues that any cost driven to meet demand is demand related. He cites Alfred Kahn, however in that particular citation, Kahn was referring to a market where there are multiple suppliers and where generation resources are shared by many customers. It is not directly applicable to the case of distribution costs. The marginal transformer cost at a particular location varies with customer numbers and not with their discrete increments on usage if the right design demands have been considered when planning the system.

Q. How does the MDS and Basic Customer approach compares with regard to allocation of conductors and transformer plant?

A. Figure 1 below shows a comparison of relative class allocation shares of total marginal distribution facilities as per the PSNH's MCOSS compared to the allocations of net plant by class in the PSNH's ACOS and to an alternative ACOSS which relies on the Basic Customer approach which assumes that all distribution accounts except for meter and service drop are demand-related. This comparison is only indicative as it includes net plant allocation but not allocated expenses. Transformer plant for rate classes GV, LG and Rate B are excluded for comparison purposes since these customers typically either own or rent the transformer. As expected, the Basic Customer approach reduces residential class cost responsibility. There is a significant difference in the residential class with respect to the ACOS Basic Customer approach. Only 52.3% of the accounts 364-368 gets allocated to the Residential class, vs. 69.6% under the MDS approach. All commercial classes get correspondingly a higher allocation with the BC approach. The small commercial or GS class cost allocation is only slightly higher using the BC approach (22% vs. 18%). The main difference is in rates GV and LG, both receiving more than double the allocation of costs under the BC method, since they have a much higher kW of demand per customer as compared to residential class. The higher allocation to GV and LG in the Basic Customer approach as compared to the MDS relative allocation reflects mainly the impact classifying 100 percent of primary lines as demand-related, vs. considering only 64% (on average across the three accounts 365-367) as demand-related in the MDS study. No secondary conductors or transformers are allocated to these two classes. The risk is that the BC allocation equally weights the per-kW cost across customer classes, ignoring any economies of scale. Because of this, there is a higher potential that with the BC approach the medium and large general service customers are not be priced competitively, thereby providing a stronger uneconomic incentive to bypass the Company's grid system with distributed generation and potentially energy storage.

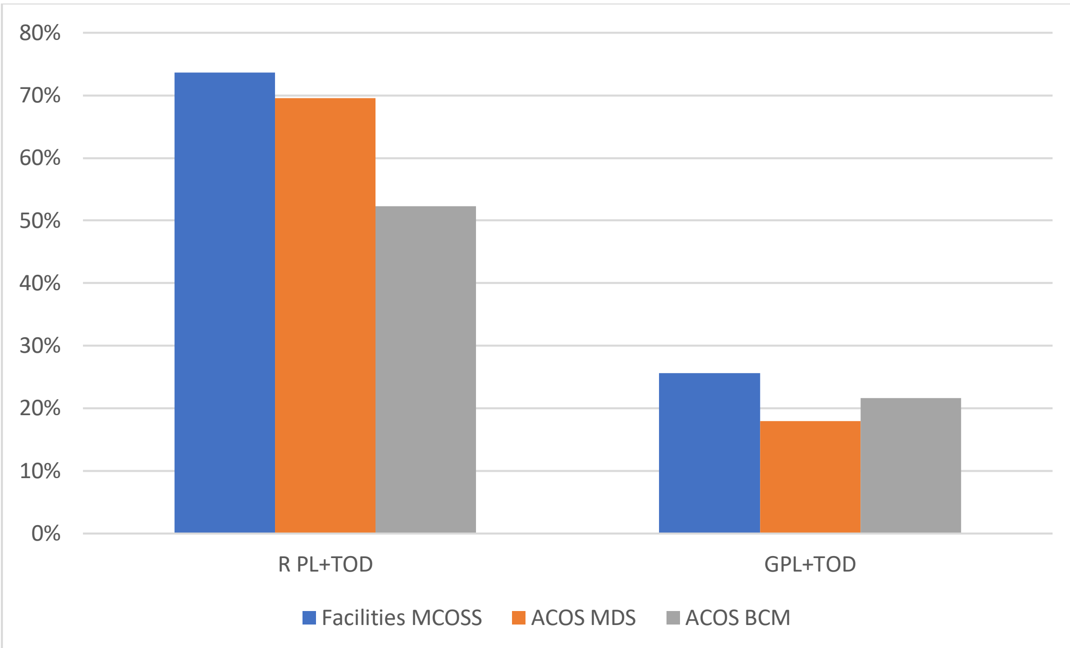
Figure 1. Comparison of Accounts 364-368 Cost Allocations under the MDS and the Basic Customer approaches



Q. What would you consider to be a relevant benchmark when assessing the appropriateness of a particular ACOS study method?

A. When a utility relies on an embedded or ACOS study as the basis to set class revenue targets, which is currently the decision adopted by PSNH, the particular cost drivers for upstream and downstream distribution facilities should be, to a large extent, comparable to those considered in an MCOSS . This means that one way to test whether the current classification of ACOS would lead to seemingly efficient cost allocations is to compare the relative class allocations for this component of service that result from the MCOS analysis. I see value in analyzing how to interpret the results of the MDS study relative to the Basic Customer approach when it comes to informing the appropriate customer charge and comparability with a marginal cost-based study. The goal is to test whether MDS resulting allocations keep a similar class share of the total facilities embedded costs (net of customer contributions in aid of construction) as compared to class allocations in the MCOSS. Figure 2 below compares MDS with the class allocation of facilities costs. It is important to note that the MCOSS does not assign marginal facilities costs to GV or LG because they either own or rent their own transformers, therefore the chart below only shows the comparison for Residential and GS classes. This chart illustrates that if the class revenue requirement associated with accounts 364-368 was decided using a facilities marginal cost allocator, both the residential and the GS class would receive a higher allocation. It also reflects that treating all plant in these accounts as demand-related would lead to a significant under-allocation of costs to the Residential class, compromising the equity of cost allocation and potentially the efficiency of price signals. I believe that the MDS creates the least distortions to the residential class revenue allocations and rate design, and more so in the current context of low peak demand-related investment and low marginal substation costs.

Figure 2. Accounts 364-368 Cost Allocation under MDS and BC approaches and Comparison with Marginal Facilities Costs for Residential and Small Commercial



Q. What would be the implications of the Basic Customer approach for rate design?

A. Using a classification of 100 percent demand-related for the transformer, secondary lines and local primary lines would lead to a suboptimal price signal. By considering transformers and local primary wires as investment that varies with on-going maximum demand in a given billing period the ACOS study would imply that the full cost of the transformer must be recovered in a volumetric rate, either kW of maximum demand in the billing period, or peak period kWh. Neither charge would be appropriate. Instead, customer designated back-up contract demand would be more suitable and consistent with planning capacity. In addition, the fact that transformer sizing does not look at a particular test year's customer demand and as such is not avoidable when the customer demand is lower in a given year. Any unused transformer capacity may not necessarily be needed to meet the demand of the other customers connected to it. In other words, the required installed capacity is partly a function of standard sizes adequate to meet total demands of each customers in the long term, and not simply a function of actual discrete additions of demand. This scenario is consistent semi-rural areas which is the case of PSNH. When there is less of an opportunity to share capacity the cost driver is not the maximum metered demand in a given billing period because a reduction in that demand will not lead to any cost savings for the utility.

Q. What support does Mr. Nelson provide for his recommendation of the Basic Customer approach?

A. Mr. Nelson cites the NARUC Electric Manual since it mentions a method similar to the basic customer approach, however it is in the context of the Marginal Cost methods discussion. He also references twelve states that according to him have embrace the Basic Customer method. Finally, he cites a publication of the Regulatory Assistance Project ("RAP") dated as of year 2000 as having estimated approximately 30 electric utilities use methods that do not classify any portion of the distribution system as a customer cost. Mr. Nelson provides no context for the 30 electric utilities and their choice to utilize other methodologies that do not classify any portion of the distribution system as a customer cost. More importantly, Mr. Nelson provides no data as to whether these utilities use a Marginal or Embedded cost of service study. Without further detail behind the RAP estimate it is not possible to fully assess the extent that this method has been applied in the context of an embedded or allocated cost approach and whether the method was applied in its more strict version that treats transformer and lines as 100 percent demand-related. For example, in several states that use the Basic Customer approach such as Iowa, the cost of the transformer or account 368 is part of the "bucket" of customer-related costs. It is also important to note that in one of the states that he mentions (Connecticut), MDS is still the core methodology used.

Q. Do you consider that the Basic Customer approach is widely accepted in the industry?

A. The "Basic Customer" approach has been adopted by a number of utilities in the U.S., as indicated in Mr. Nelson's testimony. However in some of the states that he mentions, the Basic Customer approach has not ultimately been relied upon to set class revenue allocations, and instead it is only used as a reference as part of a range of customer cost allocation methods requested by the Commission. It is also important to note in both his testimony and response to interrogatories, Mr. Nelson implies that the Minnesota Public Utilities Commission (PUC) is a proponent of the Basic Customer approach, however I find this not to be a true representation of the Minnesota PUC's position in all cases. For example, as part of the Xcel Energy's rate case in 2017, the Minnesota PUC requested the development of a range of COSS methods (Docket E-002/GR-15-826), including the minimum system approach, the zero-intercept approach, the Basic Customer method and the Peak-and-Average Method, for an assessment of the range of results and the merits of the rationale behind each method, and potential use in determining class revenue apportionment. Upon a review of the methods and the various stakeholder and intervenor positions, the Commission concluded that the proposed use of Xcel Energy's MDS analysis, along with the zero intercept approaches were reasonable. In particular, the PUC ruled to approve the revenue apportionment proposed by the Company, thereby implying that the Company's use of the "hybrid" method, which relied on both methods, choosing the lowest customer-related share which for some plant accounts was provided by the MDS analysis, and for others by the zero-intercept approach.[1]

> "Having given due consideration to each CCOSS in the record, and having reviewed the parties' proposals, the Commission concludes that the first year of Xcel's proposed apportionment best balances the competing considerations."

In addition, the Commission explicitly found reasonable the MDS approach prepared by the Commission, stating the following:

> "The Chamber, the Commercial Group, the Department, and XLI generally found this classification method to be reasonable. However, the Department argued that Xcel could improve upon this CCOSS by incorporating data from additional years, and by adjusting its booked cost data to account for inflation."

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[1] In the Matter of the Application of Northern States Power Company-Minnesota for Authority to Increase Rates, Docket No. E-002/GR-15-826, Findings of Facts, Conclusions and Order (June 12, 2017).

In addition, in the same Order, the Commission says the following in discussing the drawbacks of the Basic Customer approach:

> "The Chamber, the Department, Xcel, and XLI opposed the Basic Customer Method, arguing that this formula would fail to classify costs based on cost causation and would be inconsistent with many prior Commission orders. The Chamber expressed concern that this method would allocate excessive costs to Xcel's commercial and industrial customers, making their operations uncompetitive with firms operating in an environment with cheaper electricity."

Q. Mr. Nelson states that the Company is seeking to allocate more costs to the Residential class by using the MDS study. What do you think regarding this position?

A. I disagree that the Company is seeking to arbitrarily apply more costs to the residential customers. The ACOS study essentially adheres to the principles of cost causation as recommended in the NARUC Electric Manual, which has traditionally been the condition that Commissions in NH and other states have requested the utility's ACOS studies to meet. The NARUC Electric Manual discusses either a Minimum-Size approach or a minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) for those accounts. Under both types of studies, the plant accounts are split between customer and demand-related costs. The NARUC Electric Manual does not recommend a basic customer approach for embedded cost of service studies.

Q. What do you think about Mr. Nelson's concern over using plant re-stated in today's dollars in the Minimum System Study?

A. Mr. Nelson considers inadequate the approach that the Company followed, which started with original plant cost and then adjusted it to re-state it in today's costs using Handy-

Whitman Index, for all plant inventory. This is the approach that the Company has used in prior rate cases, and it has previously been found consistent with NARUC's guidelines. It is widely accepted in the industry by energy regulators as a reasonable way to conduct the study. Using the 'average book cost' would require restating the minimum size as well to calculate and apply the average vintage or service life in the account. It would in principle not be different from what the Company has done, which is stating both total plant inventory and minimum system in today's dollars, equivalently to imply that the system has been put in place from scratch in 2019. The cost of the minimum system study, expanded to the total population, provides a customer percentage factor. By applying this factor to total plant in the account, the underlying assumption is that the minimum system is of the same average vintage as the rest of the plant. It also assumes that (1) all assets in that particular account depreciate at the same rate annually, and (2) their market value changes at the same rate. Both assumptions are reasonable given the need to simplify the calculation. In addition, Mr. Nelson, p. 88, states that the study should use the average book cost of the existing minimum size equipment. I am not aware of any ACOS study that uses the current average "book" cost in calculating the customer and demand shares of the minimum system study. The Company instead, used the current installation cost for new equipment, to be consistent with how the rest of the plant inventory is valued. This approach has industry precedent.

Q. Is the average book unit cost method superior to the method used by the Company to compute the demand-related portion in its MDS?

A. Not necessarily. The accumulated depreciation specific to the minimum system relative to all plant inventory needs to be tracked down. The test year net plant value by size and type in the account may be unknown. The only way to do this calculation with a reasonable degree of accuracy would be by taking each element of plant inventory's vintage and accumulated depreciation into account. The difficulty of this exercise in this type of study is that the ACOS analyst has only aggregated plant accounting data to work with.

Q. Should the study use a historical minimum size as suggested by Mr. Nelson?

A. PSNH used the currently installed minimum size of each distribution element rather than a historically representative minimum size. Mr. Nelson objects to this element of the study as well. He argues that the study should use the minimum size "historically used". Using the historical pole height would be at odds with the NARUC's recommendation. The NARUC Manual (pages 91 and 92) specifically states that the chosen minimum size should be consistent with the asset currently being installed, as opposed to the minimum sized historically installed. A historical minimum size could be adopted only if it were generally representative of the assets with average vintage in the account, to avoid that the system associated with the minimum pole would be underestimated. Accounting and tracking the depreciation of historical installed minimum design size equipment could prove an impractical solution.

Q. What other issues does Mr. Nelson's raise in the context of the Company's MDS study?

A. Mr. Nelson does not agree with separating single and polyphase lines in the study. Such separation is necessary to avoid allocating costs to customer classes that primarily use three-phase lines. The majority of residential customers receive service off the single-phase primary distribution system. By contrast, there is a larger share of commercial customers that receive service from the single-phase primary distribution system. Mr. Nelson's argument to combine the allocators for both single phase and polyphase alludes to the fact that distributed generation (DG) produces two-way power flows. This argument does not support the use of a combined allocator. Even if there are customers with distributed generation that export to the distribution grid and effectively supply other customers within a local distribution area, the DG 3-phase customer is not responsible for making the utility incur in single-phase facilities.

Q. Are there other elements of the ACOS study that Mr. Nelson objects to?

A. Mr. Nelson appears to agree with the hybrid allocator for station plant (Acc. 362) and associated expenses except that he proposes to look at more hours beyond the summer peaks. As Mr. Nelson mentions, only about 9 percent of the total bulk substation in terms of nameplate capacity in PSNH's service territory peak in the winter (representing about 9 percent of the peak load). The ACOS study is not seeking to develop substation-specific allocators, since the cost allocation is done by customer class and not by specific location. Thus, using customer class' coincidence to the higher peak hours in the summer for the allocation of bulk substations is appropriate as it reflects the peak timing that drives investment in the majority of the substations. Using a weighted average of winter peaking vs. summer peaking class responsibility would not change the results materially. Mr. Nelson does not propose any specific allocator as an alternative to the 20 CP. He also appears to acknowledge that the hybrid approach employed in the ACOS study is an improvement over the traditional use of class NCP allocators which masks the highest cost contribution of summer peak. I continue to support the use of a 20 CP or 20 CP/NCP hybrid methodology based on the significance of customer demands during the summer months as a driver of substation investment decisions. Summer peak demands predominate on the PSNH's system. While winter peaks on some substations have exceeded the summer peak under certain weather conditions, the summer peak drives the need for capacity on the system. Overall, customer usage outside of July and August is unlikely to drive the need for additional distribution capacity on the system.

Q. What is your conclusion as to the overall approach of the Company's ACOS?

A. As mentioned in my direct testimony, I reiterate the Company's minimum system study conforms to NARUC's guidelines and the overall ACOS study relies on widely accepted embedded cost study methods.

III. MARGINAL COST OF SERVICE STUDY

Q. What were the main areas or comments from the OCA witness Mr. Nelson regarding the MCOSS that you prepared for the Company?

A. OCA's witness Mr. Nelson mainly objects to aspects of the approach used in the MCOSS to calculate the marginal local facilities costs and customer costs. He also takes an issue with data input updates with respect to the MCOSS that was filed in July 2018 as part of the Net Metering Docket.

Q. Are Mr. Nelson's concerns over the updates to the study reason enough to recommend the Commission not rely on the MCOSS?

A. Definitely not. First of all, the 2019 PSNH's MCOSS relies upon best practice methods in marginal costing and has involved a significant amount of scrutiny. The marginal methods that I employed are unbiased, and consistent with sound economic principles. They have been thoroughly vetted and accepted for consideration in ratemaking decisions by Commissions in California, Nevada, Oregon, New York and Maine, and practically in every US jurisdiction that relies on marginal cost studies as the basis to inform necessary changes to rate structure or levels. Secondly, what Mr. Nelson qualifies as "subjective" assumptions or 'strategic' updates, are the result of an enhancement exercise that was performed in the interest of ensuring that the input data was aligned with the latest planning and cost information available. The fact that there were different results in no way means that the earlier study was erroneous. Rather, it was based on the best information available at the time and reflected the Company's understanding of the nature of investments in the capital plan. Third, the only material impacts in the marginal cost estimates were with regard to the bulk and non-bulk substation marginal costs. The marginal facilities cost estimates by customer class and the marginal customer cost estimates only minimally changed with regard to the prior study.

Q. Does Mr. Nelson's testimony provide any evidence that the Commission should not rely on the 2019 MCOSS study for rate design or revenue allocation purposes?

A. No. Again Mr. Nelson's comments leading to his conclusion that the MCOSS should not be used for rate design are entirely subjective since they are unsupported by any evidence. The study involved a review of the Company's planning process, the assumptions behind the various planned investments, the cost and physical characteristics of customer connections by each rate class. More importantly, the study has not been found to present implementation errors or flaws that warrant such conclusion.[2] . The revised study results are perfectly suitable for use by the Company in its ratemaking process.

Q. Does Mr. Nelson imply that the updated study was changed to find a particular outcome other than simply updating information?

A. Mr. Nelson goes on to assert, in page 102 of his testimony, that there are only two possible reasons why updates lead to different results as compared to the July 2018 MCOSS. One being that one of the two studies must be inaccurate, the other that the Company has exerted undue influence on the studies by "acting strategically for financial gain". Later in his testimony, he clarifies this comment, by stating in page 105: "PSNH is making or changing

[2] The earlier version of the MCOSS had initially included energy efficiency program expenses in the marginal customer account costs due to an oversight, however this was appropriately addressed and corrected, and it slightly reduced the residential marginal costs. The revised study was submitted to the Commission and to Mr. Nelson on a transparent basis, prior to Mr. Nelson's preparation of direct testimony.

assumptions to justify increase fixed cost recovery". He also states that this a "common theme in both the cost studies submitted".

Q. What is your reaction to these conjectures of Mr. Nelson?

A. Mr. Nelson's statements are pure speculations and lack any logic. He also is undermining long-standing cost of service methods in a rather subjective manner. His position represents a puzzling attempt to inoculate bias in the cost of service studies and blatantly questioning the independence of the studies, all because he considers that the approaches chosen for the cost allocation are those more likely to secure profits to the utility. Mr. Nelson surely is not unaware that the two studies that the Company has filed in this rate case, both marginal and embedded, follow long-standing cost practice methods and have regulatory precedent in many jurisdictions. Judging by the ease with which Mr. Nelson disregards the MCOSS study, it appears that that Mr. Nelson may be indicating lack of experience conducting marginal cost studies, as perhaps unawareness on the implications of second-best economic theory in a natural monopoly context and implications for pricing. Mr. Nelson's characterization of the approach does not provide me with the confidence that he fully understands the work that went into the development of the Company's MCOSS. He points at the outcome of the various study updates and proceeds to elaborate a conjecture regarding the motivation for such changes, rather than evaluating and recognizing the need for updates, which in any case allowed higher precision in the particular cost drivers of each component of distribution service. It might also be useful to note that development of the 2019 MCOSS took advantage of a relative longer time frame, spanning over five months, compared to the much shorter period of the earlier study. The longer timeframe during the preparation of the 2019 marginal cost study was helpful to gather and review new forecasts, as well as for the Company to have time to familiarize itself with the purpose and methods of the study.

Q. What other criticisms does Mr. Nelson offer on the MCOSS?

A. Mr. Nelson considered that the cost impact of any changes in data inputs should have been described as a separate document. It is unclear why this is the case, since ascertaining the impact of the updates only requires a comparison of the tables in the reports produced for the two studies, both of which are filed on the Commission's website. The reason why the various updates were not directly discussed in my direct testimony is simply that the 2018 MCOSS was part of the NEM docket DE 16-576, a separate proceeding altogether. The changes were enumerated as part of the updated Marginal Cost Study report that was subsequently filed under such docket and therefore the updates were fully transparent. Again, they include changes driven by updates to inputs to the study, including system hourly loads, regional load forecasts, and projected timing and magnitude of the capacity-related investments, all of which were relevant for the study. The customer account and customer service weighting factors were also updated in the 2019 study to reflect the more recent and detailed class responsibility analysis that PSNH conducted in preparation for the rate case. In short, the MCOSS approach reflects an objective assessment of the

Company's data and specific circumstances of the nature of the investments and required extensive consultation with the Company to obtain further information or clarification about the data provided.

Q. Does Mr. Nelson make an inaccurate statement about the impact of an updated MCOSS?

A. Yes. In page 102 of his testimony, Mr. Nelson states as follows: "As a result of the lower capacity-related station costs, the study produces a lower marginal volumetric cost of electricity, which also leads to higher fixed monthly charges. These changes align with aforementioned utility economic incentives." This statement is incorrect. The 2019 MCOSS did provide a lower marginal annualized cost for distribution substations, however the monthly marginal residential customer costs also *decreased* from $16.12 to $14.90. Mr. Nelson's conclusion that lower marginal volumetric cost of electricity will lead to higher monthly fixed charge is actually irrelevant since the Company has not actually proposed reducing the volumetric charges to the underlying marginal substation cost.

Q. Why is it important that the Commission dismisses Mr. Nelson's claims on the MCOSS validity?

A. Mr. Nelson is adamant about the need to reject a marginal cost study, just as he is proposing that the Commission ignores the results of the allocated cost study, despite both being consistent with best practice. His testimony clearly shows a strong preference for methods that allocate costs to commercial customers. He ultimately abandons any method to propose a simple across the board increase to all customer classes. The Commission should consider the MCOSS' role in this rate case as well as future rate cases, since it is important and relevant as a helpful benchmark to assess the efficiency of the allocation of revenue requirement to customer classes, and to the specific going-forward unit cost estimates that help determine the appropriate levels by rate component and time period. A forward-looking analysis is critical to set the appropriate price signals that convey the required information as to the cost implications of customers decisions, as opposed to a backward-looking embedded cost study. Setting rates using more current, 2019 MCOSS results will be critical. Furthermore, the study also sets the basis for developing more granular, time-differentiated price signals as the Company prepares for future customer adoption of solar technologies, battery storage, and electric vehicles.

Q. What were the main reasons for the differences in results with respect to the Company's 2018 MCOSS?

As discussed earlier, the revisions reflect updated Company's planning criteria as of April 2019, and other new data such as updated FERC accounts, and class customer weighting factors for customer accounts and customer service expenses. These updates do not render the study less useful. To the contrary, they strengthened the study results and its suitability to inform the basis of both revenue allocation and rate design. Thus, Mr. Nelson's recommendation of not relying on the MCOSS for rate design or revenue allocation on account of the various updates or his mischaracterization of the study is simply not justified.

Q. What is your position regarding Mr. Nelson comments on the change in bulk station costs?

A. Mr. Nelson points at the fact that the marginal bulk and non-bulk station costs were lower in the 2019 MCOSS as compared to the 2018 study. I provided an explanation regarding this change with the filing of the updated study. To reiterate such explanation, the 2019 MCOSS estimates relied on more precise information disclosed by the Company planners as to the likely nature of a large transformer substation investment in the later years of the planning period, i.e., beyond year 2022 which had been labelled as being capacity-related in the initial MCOSS. During the process of enquiring the Company about any updates that might have been made to the five-year distribution capital plan, the Company provided additional input regarding the initial uncertainty of that large investment. They confirmed that while the projected investment continued to be notional, i.e., not tied to specific substations or locations, it was unlikely to be used for capacity-related expansions, and instead would address asset condition needs. The 2019 MCOSS took this planning decision into account and a revision was made to reflect the more up to date investment scenario.

Q. Please indicate the various updates to other inputs in the calculation of bulk and non-bulk station costs.

A. PSNH's updates its long-term distribution peak load forecast annually, and the MCOSS reflects this updated coincident-peak load growth forecast by station and region, including any known step load changes by substation. In addition, the Company clarified that the non-bulk substations planning criteria has not yet been updated and as a result they are currently due for expansion only when its projected load reaches the transformer's long-term emergency (LTE) rating. For non-bulk substations, only a few projects in the updated PSNH's capital plan are needed to expand substation capacity to accommodate projected load under n-0 or n-1 conditions.

Q. In your opinion, are the low marginal bulk and non-bulk station costs consistent with the load growth information?

A. Yes. The low system-wide marginal substation costs resulting from the 2019 MCOSS study are consistent with the fact that the updated peak load forecast relied upon continued to show slow growth, and for some of the substations, a capacity update was already taking place in 2019. Only a subset of the substations with projected peak loads that will exceed the 75 percent threshold required to satisfy the n-1 standard by 2024 will be expanded due to the Company's unequivocal statement that asset condition projects will be prioritized over capacity expansion-related replacement projects over the next five years. The implication is that for a number of stations, the violation of n-1 standard is expected to be moderate enough so as not to require immediate action by the Company. As a result of the changes, the share of the PSNH's load located in areas expected to experience bulk station capacity-related projects during the five-year horizon changed from 33.5% to about 20%, contributing to the lower system-wide marginal bulk station cost estimates.

Q. Does Mr. Nelson agree with the approach that was used to estimate marginal local distribution facilities costs from a methodological point of view?

A. Not entirely. Mr. Nelson appears to agree that the local facilities should be treated differently than the upstream distribution facilities. He also takes no issue with using the Company's history of connection jobs to estimate the installed cost and size typical of each customer class. Yet, he has concerns regarding the local facilities cost stated on the basis of kW of customer's "design demand" as the cost driver for this component. As I explained in my direct testimony, design demand is a useful concept to characterize what drives the investment on transformers and local lines. The design demand concept is consistent with the actual decision process that utilities follow to install transformers and conductors. Contrary to Mr. Nelson's statements, the concept of design demand is not new in the industry. The term may vary from utility to utility. Analogous terms are 'customer reserved level of capacity', 'contract demand', or 'connected load', but the meaning behind the term is essentially the same. Where design or contract demand is not recorded for each customer, reasonable proxies for billing these charges are the transformer size for customers with a dedicated transformer, the highest monthly demand recorded in the last two or three years for customers with demand meters, or for customers without demand meters, the standard design demand assumed by distribution planners for that type of customer (residential all-electric, residential mixed electric and gas, very large residential).

Each residential or commercial customer expects its distribution company to stand ready to deliver all their energy needs, in essence they expect to receive "firm" energy service, which is associated with a reserved level of capacity at the transformer, in exchange for the rate assessed to the customer. Therefore, distribution capacity planning takes into account the maximum demands of the customers. These facilities are installed to have sufficient capacity to serve customers' individual peak load requirements or planning demand. The design demand recognizes this implicit firm capacity agreement, in lieu of a contract demand when it does not exist. Only when there is an agreement or subscription option in place, by which the customer commits to a maximum demand level, would the customer be assessed a lower charge.

Q. Please explain why Mr. Nelson's proposal fails to reflect the cost driver for investment in transformers.

A. Mr. Nelson appears to claim that the on-going customers' non coincident demand is the driver for investment decisions on the size of transformers and local lines. This does not reflect the way that distribution planners expand these facilities. The maximum customer demands may fluctuate year to year and season to season based on weather and other temporary variables, yet these fluctuations do not change the required need of the transformer capacity that needs to be reserved to the individual customer. Finally, design demand or planning capacity represents a distinctive measurable aspect of customer service requirements, different from energy usage, metered peak or metered non-coincident peak demand, and therefore it belongs in a separate, "grid access" component of the rate. The choice of transformer is related to the individual expected demand on the long-term, thus the customer's "design demand" is the cost driver for this component of plant.

Q. Do other utilities or industry analysts use design demand in facilities marginal cost calculation?

A. Yes. Again, whether they use the same term or not, the basic concept is well understood and has been approved by Commissions in MN, ND, SD, California, Nevada and Oregon. I have used this term in many marginal cost studies that I have conducted to date, since it helps explain the nature of the local marginal distribution facilities costs. I have also discussed the concept of design demand in industry workshops where I have presented or trained on marginal cost and pricing methods for utilities and regulatory commissions in the past. In those discussions, design demand is a helpful term in the context of the cost of service study to distinguish it from the demand that planners take into account when installing upstream facilities.

Q. Does PSNH rely on design demand, unlike what Mr. Nelson states?

A. Mr. Nelson's claim that PSNH does not use a measure of design demand is misleading. As I discussed in my direct testimony and interrogatory responses, PSNH's engineers implicitly consider the long-term non-coincident maximum demands of the customers who will be served from those facilities. The term 'design demand' may not be by itself in the Company's planning protocols, but engineers use this notion to decide among the various standard sizes of transformers available to accommodate the sum of customers' design demands across customers served from a given transformer, adjusted if necessary, for a small coincidence factor.

Q. Does Mr. Nelson misunderstand the calculation of the design demand?

A. Mr. Nelson provides an incorrect description of the calculation of 'design demand'. In page 120 of his testimony, lines 12-13, Mr. Nelson states that "To estimate design demand, Witness Nieto divides the cost of local facilities, by the average number of customers". This is the wrong description of the calculation. I used the kVA of the median transformer size, not the cost. Transformer kVA for the typical transformer divided by average number of customers that the Company would expect to serve from that transformer is used as a proxy for average customer design demand. In determining the average number of customers, I enquired the Company to provide the distribution of customers served by transformer size and consulted with engineers on the appropriate size for a given number of customers of specific characteristics.

Q. Are you aware of other utilities using this marginal cost approach?

A. Many utilities' distributed generation rates use a similar concept, the contract or reservation charge, which is rooted in the concept of design demand. A number of utilities' MCOS studies consider the fixed nature of transformers during the service life of these assets when deciding the appropriate rate component for this cost. Otter Tail Power Company uses a marginal distribution facilities analysis, as do NYSEG, RG&E, CMP and other utilities. NV Energy uses a marginal cost of facilities that is based on allowances used in line extension policies. The allowance is set for the average customer in the class, and is set on the basis of standard installations, which in turn consider the capacity required to meet that average customer. The 'design demand' is also analogous to the concept of contract demand that many utilities employ for large users or for customers with on-site generation.

Q. Did you have PSNH's records of specific design demand when estimating the facilities marginal costs?

A. I requested records of customer specific design demand for the various types of customers. This information was not available, however, and as a proxy for purposes of the study, I reviewed information on transformer installations, in particular, the size of the transformers typically used for residential and general service customers, and average number of customers typically served by a transformer. I used the information on transformer capacity divided by average number of transformers as a proxy for average customer design demand in those classes, separated by single-phase and three-phase. Thus, the study produced a cost per-kW of average transformer capacity assigned to an individual customer within the class. If the Company were to use a facility charge based on contract demand or maximum non coincident demand, the charge can be restated as a dollar per kW of customer-specific contract demand, using the appropriate equivalence. For purposes of presenting illustrative marginal cost-based rates, using the Company's current residential rate structure, which does not include a facilities charge, I calculated local facilities costs as a monthly per-customer fixed cost.

Q. In what circumstances can a design demand charge be replaced with a fixed monthly charge?

A. The per-kW facilities cost can be converted into a monthly fixed per-customer cost (and subsequently translated into a monthly charge) assuming that there is not a significant variance between the size of the customers within the rate class, i.e., whenever the Company has sufficient expectation of a narrow variation of customer's design demands among customers in the class. For example, it would be less appropriate to use a facilities charge that is stated as a monthly customer charge if the rate included both customers in rural areas and customers in city areas, unless the line extension policy is such that it takes care of the difference in connection costs. A multi-part rate structure would be beneficial to reduce some of the intra-class cross subsidies that are inherent to all rate classes. When using only two-part rates, distribution facilities can be recovered in customer charge and any potential cross subsidy may be largely mitigated by the proper line extension policy. Careful consideration may also be needed if the rate does not differentiate between all-electric customers and gas-space heating customers. Depending on the level of use of the transformer per customer it may be necessary to have a differentiated monthly fixed charge for each type. For example, the Company may install comparable transformer sizes but serve a much larger number of customers if they rely on gas for space heating.

Q. What do you think about Mr. Nelson's concern about the use of facilities charge potentially not recognizing savings for demand reductions?

A. Mr. Nelson's criticism of the use of a design demand approach for marginal distribution facility cost appears to be rooted in a belief that this cost is avoidable when the customer reduces demand, or the cost increases with increases of the customer's actual demand. According to Mr. Nelson, the customer always helps the Company reap cost savings in transformers when engaging in a demand response program. In fact, the marginal cost would decrease only if the customer engaged in a demand response program that permanently reduces its maximum load in such a way that such reduction will effectively lead to a smaller transformer size at the time of replacement or avoid the need to expand the transformer that otherwise would take place due to other connected customers' actions. If a per-customer charge is used, as opposed to a charge per-kW of demand, a rebate may need to be used if the customer engages in a permanent energy efficiency or energy conservation investment that will ultimately allow installation of a lower size transformer at the end of the useful life of the current transformer. A customer's reduced demand does not always lead to the Company being able to install a smaller transformer in some cases, for example if simultaneously, other customers on the transformer are permanently increasing their loads. The Company will however recognize that the customer has a lower than the average customer 'design demand' in the eyes of the distribution planner. In that narrow scenario, there would be cost savings associated with the customer engaging in demand response or energy efficiency. The updated marginal cost is calculated with regard to such lower customer design demand. If the customer adopts energy storage, and the two-way power flow is such that net of use of the transformer is reduced, the issue would be whether now the utility is able to use the freed up capacity to meet other customers' increased loads and thereby the customer load reduction thanks to battery storage has effectively reduced transformer capacity needs in that location.

Q. What is Mr. Nelson's position with regard to the approach used in the MCOSS for facilities costs?

A. Mr. Nelson does not agree with the approach used in the study, which estimates marginal distribution facility cost on a per kW of customer's maximum design. It is based on a sample of PSNH's work orders associated with customer connection jobs in years 2015-2017 involving transformers, local primary conductors and secondary voltage lines. In his testimony, Mr. Nelson claims that this approach, also sometimes referred to as the "rental method" may not work since it is based on the premise that there is a competitive rental market for meters and services. He also states that "… the rental method is based on a flawed theoretical premise that results in an estimate of value instead of marginal costs incurred by the utility." He suggests that the marginal cost method needs to look at the cost of connection of new customers only, which in the industry is referred to as the "New Customer Only" (NCO) approach.

Q. Do you think that marginal connection costs based on the rental method overestimate marginal residential facilities costs?

A. No. Mr. Nelson misunderstands the "rental method" because the objective of a MCOSS is intended to guide the development of economically efficient price levels, and this requires estimating the marginal cost that would be associated with an increment of unit in a marketplace, even if no such rental option currently exists for the residential customers. The per-kW rate reflects the monthly price that any average customer is expected to face when connecting to the grid, for the duration of the service. It also reflects the opportunity cost for an existing customer of demanding an additional unit of design demand (readiness to serve a large load addition when such addition will affect the peak loading on the specific transformer or circuit) to be served by the Company. The utility is responsible to provide customer access in perpetuity, unless the site is permanently abandoned. Thus, distribution facilities cost estimation looks at the current per-kW rental value of the average customer connection in the class, existing or new. At the same time, this price reflects the cost per kW of incremental design demand that an existing customer may demand at any given time. The marginal cost is only incurred when the facility is put in place, when a customer changes design demand (perhaps requiring a new transformer, which should occur very infrequently unless the customer adds atypical load) and when it is time to replace the transformer.

Since potentially any new customer could add load that would require replacement of the transformer, it is a fee correctly applied to all customers as a proxy for the marginal value that such service would have in a market. Considering the whole customer population in the class when computing marginal cost-based revenues essentially provides weighing of the possibility that each of those situations occur in proportion to the overall design demand estimated for every customer class.

By treating all customer population as marginal, the class marginal cost relationships allow to reflect the proportionality of transformer and wires capacity requirements by the typical customer in the class, providing the relative cost of connecting at one voltage level vs. another and across classes, which is critical for use in rate design. A short-run marginal transformer cost analysis intended for locational distribution pricing would require an analysis by location, size, timing of customer new connections and other factors. This analysis across the entire service territory would be time intensive and not helpful as the basis of a marginal facilities price signal for the average customer in the class to be used in setting system-wide distribution rates.

Q. Do you believe that there is any merit in considering the New Customer Only method that Mr. Nelson discuss?

A. No. The MCOSS is developed to inform the level of tariff charges that will apply to *all* the Company's customers and should only differ based on the customer's relative size of connection and the specific infrastructure used to serve the customer (e.g., whether it is primary vs. a secondary connection). When the rate does not differentiate by voltage level, single phase or three-phase, the charge represents a weighted average. Beyond that, there should be no differentiation between new and existing customers, simply because the tariff does not discriminate between existing customers or new customers in what the customer pays through rates.[3] Any cost of service study approach, embedded or marginal, has relative strengths and weaknesses, and then, the strength or merit of the particular approach is linked to the specific study application, in this case rate design. The NCO-derived per customer cost will be too low of a price signal for any new customers considering a move into PSNH service area, as well as much lower than the full economic value of the interconnection facilities serving the existing average customer in the class. NCO calculations essentially calculates average incremental customer costs from a financial, or cost recovery, point of view. By contrast, the rental method is consistent with economic principles and allows the consumer to decide whether to connect or add a specific large load that would drive up its design demand.

Q. How does the Company's line extension policy affect the price signal provided to a customer to connect, and has Mr. Nelson appropriately considered this?

A. Connection costs only include those that are not part of the up-front payment. If all costs of the connection of the customer premise to the grid were paid off up-front, there would be no need for a per-kW or customer facilities charge in the rates. A new customer is

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[3] The only instance where such a differentiation is relevant is in the case of tariffs for economic development, because there may be specific goals affecting the fee assessed to these customers.

generally assessed an upfront fee. The premise of an upfront payment is that the overall connection cost exceeds the standard investment level, for the customer type, which is already recovered in rates. The sum of the customer up-front payment along with the monthly connection fee represents the full economic value of the interconnection facilities serving an existing customer or a potential new customer.

Q. **What are OCA's witness concerns regarding PSNH's calculation of marginal customer cost?**

A. In discussing concerns about the marginal customer cost analysis, Mr. Nelson mentions that there were several updates with respect to the prior study such as those made to the marginal customer service and account expense weighting factors. The customer expense allocation factors depend on the Company's assessment of the relative level of effort or responsibility that each customer class require for each of the customer accounts. Mr. Nelson does not offer any substantiated comment as to the reason for taking an issue with these updates. As with other aspects of the study, updates to the class allocations were made to reflect new information available at the time of preparing the updated study. My direct testimony explained that the customer weighting factors that feed the MCOSS are linked to the analysis of relative customer weights that are used for the ACOS study, thus, they need to be updated every time that the Company updates its customer weighting analysis in the ACOS study.

Q. Does Mr. Nelson find acceptable the approach used for estimating marginal meter and service drop costs?

A. Mr. Nelson does not agree with the approach employed for marginal meter and service drop costs. Instead, he favors again the NCO method. The NCO method calculates the total cost per customer for any given class, and at any given year, of installing and maintaining a new meter and service drop to new customers, plus an estimate of total new customer service expenses. The analyst then multiplies this cost times the ratio of the forecast of customer additions to the total existing customers to estimate an average cost per customer in the service area by class. The rental method provides a more equitable cost allocation of the facilities revenue requirement. The drawbacks of the NCO method have been discussed at length in state regulatory proceedings in California, which is one of the few jurisdictions that have ever used it and none of the utilities currently use it.

Q. Did Staff's consultants find any major problems with the MCOSS?

A. No. Consultants Dr. Ros and Dr. Sergici representing the Commission Staff did not object to the overall approach and methods that I adopted in the 2019 MCOSS or its inputs. In fact, they support its use for rate design and encouraged to consider it for class revenue allocation. Dr. Ros did provide a suggestion to modify the approach used for bulk stations to reflect a present value calculation. He also offered a comparative analysis of seasonality.

Q. What are the issues raised by Dr. Ros with regard to the bulk substation marginal cost?

A. Staff consultant Dr. Ros argues in his direct testimony in favor of the use of a discounted total investment method ("DTIM") to compute the marginal cost of bulk and non-bulk stations which is a variation of the method I employed. In PSNH's MCOSS, I calculated the annualized average incremental investment, also known as the Total Investment Method ("TIM"). The TIM method does not restrict the analysis to ensure that the present value of the projected investments over the five years will be equal to the marginal per-kW investment times the experienced load growth in those five years. This is because of uncertainty over annual load growth and other factors such as lumpiness of investment. For a planned investment to be deferred, in some cases, due to load reductions, the needed load reduction does rarely equate to the full peak load addition over the 5-year planning period. The TIM approach instead uses investment stated in constant dollars, so that it is possible for all annual investments to be added across years, but it does not apply a discount factor because it aims to calculate the average investment associated with a cumulative amount of load change (using project capacity addition as a proxy for load change, then adjusted by the required design reserve margin at the station) to obtain typical investment cost per unit of peak load growth.

Q. What is the DTIM method proposed by Dr. Ros?

A. The DTIM in its pure form, calculates the annual average marginal investment, which represents a weighted average investment across all years, with weights being the load increase in each year. The way to arrive to such value is by calculating the present value of the projected annual investments over the planning period and divide it by the present value of the forecasted annual load additions over the same period, i.e., discounting load growth as well as investments. Discounting the load growth is a pure mathematical exercise, just to ensure that the DTIM calculates a levelized rate, such that over time if used to price each year's load addition over the planning period, the payments will produce a stream of annual payments that, when converted into a present value, will exactly match the present value of the original projected annual investments. The notion is that if only the investment dollars were discounted to present, the resulting rate would be underestimated. The premise of this method is that the customer will not pay the full cost impact in year 1, but as demand growth materializes.

Q. Have many utilities adopted the DTIM approach?

A. The only DTIM application that I am aware of in the context of US electric rate cases is that of Pacific Gas & Electric ("PG&E"), in its last two general rate cases. PG&E's approach calculates the present value of annual load growth additions as the denominator,. Dr. Ros instead uses project capacity added, attributed entirely to the year where the project is finalized, which is not the intended use of this approach and it has implications for its validity. The resulting marginal unit cost is then annualized using a real Economic Carrying Cost ("RECC") factor that takes into account the average service life of the substations.

Q. What do you think is the main drawback with DTIM as applied to PSNH's estimation of marginal station costs?

A. The time value of the money is useful to consider when there is enough certainty on the specific year when both the investment and the unit load change assumed to impact that investment will take place. The DTIM is helpful when a levelized price needs to be determined, to compensate distributed energy resource such as a customer providing a demand response program over time. In that scenario there would be an agreed pattern of demand reductions. The reason is that the DTIM results are highly sensitive to the annual load changes or timing of demand reduction that the analysts assumes will trigger a change in the substation capacity expansion plan. The DTIM method can be considered rather inflexible, since it does not produce the right marginal cost if the presumed marginal load addition, or demand response effort, does not materialize in the same annual pattern as it was assumed. A load reduction that defers investment does not need to be tied to the precise year in the five-year period considered when the new station transformer unit will come on-line, and a capacity expansion does not always time reflective of load growth in the year that the investment takes place. This reflects one of the key issues with the implementation of this method for PSNH's case. It may be partly addressing load growth already occurring in previous years, or even years beyond the five-year horizon. To conclude, Dr. Ros' position that the DTIM would provide an apparent better alignment with time of investment or cost savings with capacity addition or load reduction ignores the limitation of the approach.

In practice, the investment incurred the year the project comes online will only be a subset of the total investment incurred, in prior year(s) to meet the total capacity addition in the particular substation. More importantly, the load change needed for the investments to be fully deferred in most cases is required already in the earlier years of the five-year period, i.e., before the project is coming in service. Using Dr. Ros's spreadsheet where he performed the DTIM calculation, I tested the sensitivity of the calculation by bringing the load change forward to year 2020. The marginal station cost decreases to $4.69. This underscores that the DTIM method is subject to uncertainty on at what point in time the load reduction could potentially defer investment will take place. This finding, coupled with the fact that only five years of planning period have been used, means that the TIM (undiscounted) approach is appropriate for use in the PSNH's MCOSS to estimate marginal distribution substation, as well as for trunk-line feeder costs.

Q. Are there other considerations that need to be taken into account as to the appropriateness of the DTIM method?

A. The emphasis of the method is to give more weight to both investment and load additions in the more imminent years. However, it produces a levelized cost, rather than year-to-year changes in the marginal per unit cost over the study period and as a result it does not present a practical better result than the TIM approach. Except for very restrictive scenarios, the DTIM does not produce an accurate value of the deferred cost associated with load reduction or the incremental cost associated with incremental usage. The DTIM as implemented by Dr. Ros only provides the right discounting method if, for example, it is used computing the payment for DER resource portfolio that would bring back the substation load to the level needed to avoid the investment in the same year that the project is expected to be in effect, i.e., precluding the assumption that no load reductions would take place before then. Extrapolating this to PSNH's marginal cost of unit of load growth is not realistic. In practice there is a lag between the completion of the expansion and the time where the load addition that triggered the need for investment (or the load reduction that would have deferred it) takes place. Thus, using DTIM would not improve the results of the Company's MCOSS. Finally, PSNH's planning horizon is only a few years into the future (two years with any certainty and five years with substantial less certainty in the specific investment to be undertaken) thus using a discount rate is not only imprecise for the reasons explained above but also has minimal impact on result due to the short horizon. The TIM is a well- accepted method in the industry and the absence of a discounting factor is not a concern for a short time frame such as five years. This is demonstrated by the results of the DTIM calculation in Dr. Ros' testimony, which are very similar to those in the MCOSS.

Q. What is Mr. Nelson concern about the calculation of the Economic Carrying Charge ("ECC")?

A. Mr. Nelson states in his direct testimony that: "Replacement costs are not growth related. Adding an additional customer to the system does not directly increase replacement costs for the utility." He is referring to an adjustment in the ECC calculation that takes into account the dispersion of retirements. This adjustment takes into account the dispersion of retirements that exist among assets of the same group type. In deriving an economic carrying charge for use in a marginal cost analysis we need a measure of the way in which an investment in utility property deteriorates (or, conversely, survives) when placed in service in order to account for the revenue requirement effect of both the initial investment and its first replacement in the field. Book depreciation charges will return the initial investment over the average life of the property installed but in real life, some of the property will last more than the average life and some less. The ECC takes into account the present value of replacement of those dispersed components (as well as components that last longer than the average service life). When load growth triggers a long-lived investment that the utility will incur costs for over a long period of time (and recover those costs from consumers over a long period of time), it cannot abandon the investment if components fail early; it will replace those components before the average service life as necessary. Otherwise it is not operating efficiently. This means that the marginal load that triggers the investment is also responsible for the costs of early retirements (and savings from components that lost longer than the average service life.)

Q. Does Mr. Nelson mischaracterize the calculation of the ECC?

A. He does. Technically the ECC is the difference in the present value of the stream of costs created by the growth and the present value of the stream that would occur without the growth (or customer addition). When customer growth requires capital investment, that essentially creates a stream of investments that include the initial investment and subsequent replacements, including replacements that must be made for components that fail before the average service life of the equipment. The ECC captures the load (or customer) growth impact on eventual replacement of the entire facility because load growth that triggers the need for additional capacity today has cost implications for many years in the future.

Q. Does Mr. Nelson mention another concern with the use of the ECC?

A. Mr. Nelson also states that a customer should not pay the same price for a new meter that she would for a 30-year-old meter, and thus he disagrees with using an ECC that assumes that marginal investment value grows with inflation every year because the older asset will have lost functionality. This is misleading because economic depreciation plays no role on the economic value of the asset if the asset is providing the same service, which should be always the case except for technology advancements that make the new asset less comparable. This means that the marginal cost this year (or appropriate amount of cost recovery or economic value of the asset) for a transformer installed ten years ago and one installed today is the same, if the ECC has the right inflation assumptions built in. An the ECC is intended to use an inflation rate net of technological progress. PSNH's study relied on a low-end of the long-term inflation rate, equal to 2 percent. There were no objective basis to determine a technological progress adjustment factor, which also may vary from plant to plant. However, the marginal cost analysis should be updated as frequently as every two or three years and at the very least when major technological advance occurs.

The meter cost that has been used for PSNH's MCOSS is that of the currently installed meter type for each class. At the time when the Company decides to replace current meters with AMI or smart meters, the calculation of marginal meter costs will need to change to account for the new installed meter cost.

Q. What is Dr. Ros' perspective regarding the proposed Time of Use periods analyzed from the results of hourly marginal costs?

A. Dr. Ros infers that the time-differentiation analysis should be deterministic instead of probabilistic. He indicates that the method employed in the MCOSS is "sophisticated and complex" and that this may be problematic.

Q. Do you find Dr. Ros' determinist approach more suitable than a probabilistic approach?

A. I recognize that many utilities use deterministic approaches to estimate the peak and off-peak periods, as well as seasonality, and others use probabilistic methods. I think that there are relative advantages of using a probabilistic approach to conduct this analysis. I do not agree with Dr. Ros' statement that the POP method is too sophisticated or not transparent. It is not particularly sophisticated. It makes use of the historical hourly loads in such a way that determines the hours with higher likelihood of being the annual's peak hour, without any exogeneous constraints, or ad-hoc assumptions as to a specific percentage threshold relative to the peak hourly load. Dr. Ros uses 90 percent and other thresholds but provides no objective basis as to which of those thresholds would need to be selected. The probability of peak analysis that I conducted is sound in it obviates the need to choose a particular threshold. The method I followed to determine hourly cost allocation factors results in the proper choice of time of day periods that are consistent with variations of those costs across hours and seasons.

Q. What are the implications of using Dr. Ros' deterministic analysis?

A. Dr. Ros' analysis leads to similar conclusions regarding the hours that are more likely to be the peak hour. The MCOSS summarized the hours for peak period 11:00 am to 7 pm. His determinist approach arrives at a similar conclusion with the exception of the distribution of probability to non-peak summer months. He finds that the months of June and September should be considered part of the summer peak season (which is Option B in the MCOSS). In other words, he finds that a 4-month summer is more cost-reflective than a two-month summer peak season that only includes July-August peak season (Option A in my analysis). His analysis shows hours within 1 and 5 percent of the summer peak in years 2015 and 2017. The probability of peak analysis that I undertook shows that the monthly level of probability of peak in those months is quite small (around 5 percent). This is because only a small number of hours are within the threshold of the peak load when combining the hourly load data for the four years 2015-2018. Therefore, the marginal hourly distribution peak cost the 'shoulder' months of June or September, calculated as the annualized cost times the hourly probability of peak in those months, is much lower as compared to the marginal costs in July and August. Using a regression analysis to determine cost-reflective periods, the Option A, which only looks at months July and August as a distinctive peak season, while other months are considered off-peak, results in a clear higher goodness of fit because it separates out the lower cost months of June and September from the core peak summer months of July and August. This does not necessarily mean that Option B (which considers all four months) should be discarded, and in fact it is probably reasonable to do so when considering that this analysis looks at the annual system peak load and not to each substation's peak. Thus, I do not have objections in considering the months of June and September as part of a summer season for TOD rates. I do believe that these months should ideally be separated as a shoulder season, because using a 4-month summer period may sacrifice the marginal cost signal in the critical two months of the summer by spreading the peak-related cost among the longer season.

Q. What are some relative advantages of the probabilistic method?

A. I have reviewed Dr. Ros analysis and my conclusion is that his determinist method as implemented gives equal weight to each year regarding on the load data analyzed. My understanding is that year 2017 was an abnormally mild-weather summer in New Hampshire. Since it was an abnormally low summer year, the pattern of hourly loads is not likely to determine the hour where load additions will trigger the need for substation capacity additions. In fac it is the only year where the summer peak load fell in June, while in other three years the summer peak took place in either July or August. The probability of peak method gives more weight to the load patterns in years with highest peak to average load ratios by way of using the average four-year (2015-2018) ratio of annual peak to average load across as the delimiter.

Q. What other comments were provided regarding the proposed TOU and seasons?

A. OCA's witness Mr. Nelson does not have concerns over seasonality although he considers that the TOU analysis should end at 8 pm as in the current TOD rate. My analysis shows that hour 7 pm to 8 pm exhibits very low probability of being the summer peak hour and that a cost-reflective peak period would begin at noon and end at 7 pm.

IV. CLASS REVENUE REQUIREMENT

Q. Please provide your opinion as to Mr. Nelson's and Dr. Sergici's comments on the appropriate way to allocate costs to customer classes

A. Mr. Nelson seems to favor an ACOS study that relies on the Basic Customer approach and reduces significantly the cost allocation to residential class. Staff consultant's Dr. Sergici states that the Company should have relied even more directly on the class marginal cost-based allocations. She concurs that PSNH's rate levels are currently out of line with either an embedded cost-based revenue requirement or marginal cost-based results. There is little doubt that class revenue targets need to be realigned while avoiding rate shock.

Q. What is Mr. Nelson's position on the Company's proposed residential average rate increase?

A. Mr. Nelson essentially disagrees with the average rate increase that the Company is proposing for the residential class in this rate case. He instead considers that the increase should be limited to the average rate increase of 4.67 percent. This is overall in alignment with his Basic Customer approach. Mr. Nelson's recommendation is somewhat surprising because the Company's proposed residential revenue target is already below what both the ACOS study and the Equal Percentage of Marginal Costs ("EPMC") methodology have indicated to be an appropriate increase for the residential class. The Company's requested increase is moderate, meaning that the residential customers will remain subsidized by the commercial and industrial customers. Both studies reveal that the residential customers are currently underpaying its share of the utility's fixed distribution costs. A pure, more strict application of marginal cost-based allocation based on Ramsey pricing, as opposed to EPMC, would probably justify an even higher increase to residential as compared to the change suggested by EPMC since the residential class is generally less price-elastic than general service classes.

Q. Does Mr. Nelson endorse a particular cost of service method to be relied upon to determine class revenue allocations?

A. Mr. Nelson is somewhat ambiguous on this point. In his testimony, he presents arguments in favor of specific ACOS methods, mainly approaches that would allocate the least possible costs to the residential class, relative to other classes. It seems that Mr. Nelson is somewhat "agnostic" about any one particular approach as he ultimately infers that decisions on rates and revenue allocation should take into account a range of methods. Even though we provided a run of the ACOS study that uses the Basic Customer approach as a response to its interrogatory, which is the method that he claims is correct, in his recommendation (as per Table 4 of his testimony) he considers that all customer classes should receive the same average increase. This is equivalent to either imply that current rates do not provide any cross subsidies, or that the cross subsidies that exist should remain. This is contrary to best practice ratemaking, which starts with the development of a cost of service study upon which decisions can then be formed to reduce current cross subsidies, taking into account the trade-off between the various rate design objectives. In the context of the electricity sector, the greatest value from the point of view of efficient use of society's resources, including customer investments in distributed generation, can only be attained when rates recognize the marginal cost differences in serving different utility customer types. This is done both through accurate class revenue apportionment that considers the expected marginal costs of each class, and with rate design predicated on a marginal cost-based structure.

Q. What is your response to witness Sergici's comments about the appropriate method to set class revenue targets?

A. I do agree with witness Sergici that theoretically from an economist point of view, class revenue requirements should approximate proportions of relative class' marginal cost-based allocation. Economists have argued for many years that class revenue requirements that consider each class' contribution to utility marginal costs, combined with prices that could more easily track the underlying marginal unit costs, are superior to ratemaking methods that are strictly rooted on average accounting or embedded costs. The price mark-up over each class' marginal costs should, ideally, be set in inverse proportion to the relative class' price elasticity of demand (Ramsey pricing's theory) to minimize deviations from optimal consumption (i.e., usage that would occur if rates were set at the marginal cost). EPMC is mostly useful as a starting point when quantitative information regarding the actual class' price elasticity for a given price change is unknown, but is a "second best" approach since it assumes that all customers react to a price increase by changing usage in a comparable manner (e.g., the same percentage). In practice, the actual difference will change depending on such factors as each individual customer's preferences and income effects.

Q. Is a shift to marginal cost-based revenue allocation as proposed by witness Sergici feasible?

A. The Company recognizes the importance of considering both marginal and allocated cost studies but has preferred to maintain the status quo with regard to the method that sets the class revenue targets. Part of the reason is that an ACOS-based revenue allocation has historical acceptance. The Company determined that it was untimely to shift from an ACOS allocation (a "top-down") approach to an EPMC approach in this rate case. I believe that the Company's proposal to continue with the top-down approach of allocating costs to customer classes in the short-term works well on the grounds of gradualism. A one-time shift to the marginal cost revenue allocation would imply a significant revision to class revenue targets, particularly affecting the residential class. It would be reasonable to implement gradual changes toward a more efficient allocation through future rate cases.

Q. Is it intuitively correct that both studies suggest that the residential customers should experience the highest revenue target increase?

A. Yes. It was expected that both ACOS and MCOS studies point at similar results, particularly for the residential class. PSNH is currently experiencing, as many other Companies in the industry, slow demand growth. In periods of stagnation of demand or customer growth, a marginal cost study based on EPMC will not be expected to provide class allocation results that are too far off from those of the ACOS study, on a per-function basis. This is because when there is slow demand, marginal delivery costs are low.

Q. Please provide your opinion as to Mr. Nelson's statement that the utilities have a financial incentive to allocate more costs to the Residential class.

A. Many utilities are well aware of the need to moderate increases to residential rates in consideration of customer bill impacts. I understand that such consideration has motivated the Company not to propose the full increase to the residential rate revenue initially suggested by either the MCOSS or the ACOS study. Again, it is necessary to bring attention to the fact that the ACOS and MCOSS studies that I conducted for the Company follow objective and vetted approaches, used the best information available and are consistent with the Company's cost drivers of investment in anticipation of planned demand and number of customers, and are consistent with widely accepted practices. In short, none of the methods used in either the ACOS or MCOS were chosen to find a particular outcome, but to be consistent with economics and cost causation. Price elasticity of demand by class is a function of consumer willingness to pay, and it needs to be taken into account as much as possible when deciding on class revenue allocation in order to minimize the loss in consumer surplus as the price is increased to recover the revenue gap. It also prevents the risk of driving large commercial customers outside of the Company's service territory on the grounds that could otherwise occur in the event of a suboptimal allocation of sunk costs. The loss of revenue when large commercial customers leave is ultimately borne by the residential class. Customers benefit from setting the rates of the more elastic customers relatively closer to marginal costs if this prevents the customer customer not to bypass PSNH's electric distribution system while contributing to the recovery of sunk costs.. The residential revenue allocation approach also needs to keep in mind the risk of uneconomic bypass, just as it is considered currently for larger general service customers. Uneconomic bypass occurs when a customer installs solar or other generation that is more expensive to build and operate than the utility's marginal cost of providing the same service. As PSNH's residential customers have access to lower cost on-site solar generation technologies coupled with battery storage, they will become more price elastic. Mr. Nelson provides no evidence to support his unfounded claim of profit-motivation behind the choice of methods in cost of service studies.

Q. Does the utility face adverse financial impacts when the residential customers pay rates below allocated cost of service, or when the energy charges are higher than marginal cost?

A. There may be more volatility of returns, however I am not aware of conclusive studies regarding the financial risk or the impact on cost of capital to the utility associated with a reduction in residential rates vs. other customer classes. An important consideration that Mr. Nelson seems to have missed in his discussion of utility incentives is the fact that it is an unproven fact that utilities always benefit financially from shifting costs away from large commercial customers and onto residential customers, or from reducing volumetric charges towards fixed charges, as claimed by Mr. Nelson. Utilities are allowed to earn a reasonable Rate of Return (ROR) on rate base. Even if shifting revenues to residential customers were conducive to PSNH earning ROR in excess of the authorized amount due to higher than forecasted sales, such over-earning would be identified in the upcoming rate case, and likely partially offset the otherwise required rate increase to meet the target ROR. Additionally, the utility's financial situation is not necessarily tied to the level of the fixed charges in rates. As long as the Company makes sure that the rates reflect the underlying marginal cost of using energy during the peak hours, and induce customer to adjust usage based on how much the customer values that peak energy in comparison with the rate. One can envision lack of financial worry even in the scenario that Mr. Nelson considers ideal where the utility set high residential volumetric charges (above marginal costs), keeping the fixed charge below marginal cost. In that case, the utility would still be entitled to recover all prudent costs, because revenue erosion experienced due to energy efficiency or customer adoption of solar DG, coupled with net energy metering, would be dealt with at the next rate case or through a decoupling mechanism. High volumetric charges, particularly in the context of net metering lead to stronger incentives for customers to adopt DG and bypass the utility system. The ultimate effect would be a cross-subsidy favoring customers that are overcompensated for their conservation efforts or DG adoption, and causing cost shifting to other utility customers. The bottom line is that the Commission, as long as the utility has demonstrated prudent investment decisions and an effort to support energy efficiency measures, would keep the utility whole financially by allowing a higher rate to all customers in the next rate case. Thus, this simply demonstrates that there would be no benefit from not such a thing as confabulation or hidden motives behind the cost of service study approaches that have been prepared and presented to the Commission in this rate case.

IV. RATE DESIGN

Q. What is the residential customer charge proposed by Mr. Nelson?

A. Mr. Nelson states that the Basic Customer approach should be used to set the price cap for the monthly fixed component of the rate. For residential customers this monthly charge is $13.82 per month, which just happens to be close to the current PSNH's residential fixed charge. In his testimony however, Mr. Nelson proposes to lower the residential customer charge to $11. By contrast, the marginal customer cost for a residential customer is at $14.26 per month, reflecting the monthly marginal cost of meter, service drop, customer accounts expenses and customer service expenses as calculated in PSNH's MCOSS study. Anything less than this price level, given that marginal cost revenues by class and overall are lower than the total revenue requirement, will perpetuate a cross-subsidy among customers within the residential class and between the residential class and other customer classes.

Q. What are the efficiency implications of not considering the marginal residential customer cost as proposed by Mr. Nelson?

A. Economically efficient pricing requires that the cost of incremental usage matches the incremental cost imposed on the utility, and society, to serve that additional load. This requires keeping the volumetric charge at marginal cost and recovering any residual (sunk) costs in the class revenue target as much as possible through the fixed charge, which is the least price-elastic component of the rate. It is generally intuitive for customers to realize that changes in the monthly bill month to month are triggered by the volumetric component of the rate. Setting a monthly charge below marginal cost does not work well in a system with sufficient capacity to accommodate most of the expected load growth, which is the case of PSNH's distribution system for the foreseeable future.

Q. What are the adverse equity implications of keeping the monthly charge below marginal costs, as proposed by Mr. Nelson?

A. Monthly fixed charge should ideally reflect marginal customer cost, and the facilities costs recovered in a separate rate, to avoid recovery of costs that do not vary with electricity usage through the per-kWh charge. Such pricing mechanism would penalize high-load factor customers, who are not necessarily imposing a higher demand on the transformer. Even if the rate includes peak and off-peak kWh charges, recovery of facilities costs through the peak per-kWh charge is suboptimal due to two reasons, one is the potential mismatch of peak period at the system level versus circuit-peak period, and the other is the revenue shortfall when peak load declines from one year to the next without a matching fixed cost reduction. Setting rate charges below marginal cost on a class-wide level has adverse efficiency and equity implications.[4] Therefore, the monthly fixed charge should be increased as suggested by the MCOSS. This recommendation is not at odds with either efficient conservation goals, or with the need to preserve affordability of electricity. Affordability requires an efficient approach to help low income customers, with targeted pricing or rebates, and not through the fixed charge assessed to all residential customers.

Q. What are the main comments of Staff witnesses with regard to the Company's proposed rate design?

A. Dr. Sergici recommends setting rates that consider the time-differentiated marginal costs as estimated by the MCOSS to send price signals to customers conducive to more efficient usage and investment decisions. I concur with this position. A properly designed TOU rate may help mitigate bill impacts of any further increases to the fixed residential charge, since the customer could reduce its bill by shifting load to off-peak hours and reducing load in on-peak months.

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[4] An exception may be a situation where the system is heavily constrained in capacity and the utility is planning on investments to meet load growth across the entire service territory over the next planning horizon. This situation does not reflect PSNH's expected near-term low marginal delivery cost conditions.

Q. **Mr. Nelson discusses that marginal facilities (design demand)-based charges may not be compatible to price customers that overload transformer capacity due to electric vehicles. What is your position?**

A. The potential introduction of a significant amount of high-current vehicle charging and heat pumps on secondary (low voltage) distribution systems arguably has the potential to overload existing distribution equipment.[5] This, however, does not invalidate the design demand concept and the associated facilities charges discussed in my testimony. If the customer does charge the vehicle at a time that compromises the reliability of the transformer, and a bigger transformer needs to be installed, this would mean that the design demand of the customer has effectively increased, above the average residential customer design demand. Sending the right price signal can be handled through a per-kW of design demand (facilities) charge, or, in absence of this charge, through recovery of facilities cost through the fixed or customer charge. The EV customer may also be given the option to be placed in a separate EV TOU rate that offers a super off-peak period charge to incentive the customer to charge overnight, or a commercial rate that charges the higher design demand, if the load for EV is not separately metered. A ratcheted demand charge or contract demand charge for customers with demand meters would in any case be preferable to a standard customer charge, but if the rate does not include it, the floor level for the fixed

[5] An EV customer may not impose transformer overload, if there is generally some unused transformer capacity.

charge should include the monthly marginal customer costs plus an (acceptable) level of the monthly distribution facilities marginal costs. When using a demand rachet, it should consider the last 24 or 36 months to make sure that customer bills do not fluctuate for temporary load reductions that do not reduce their contribution to the facility capacity requirements.

VI. CONCLUSION

Q. **What are your main conclusions?**

A. I have three main conclusions:

- The Company's ACOS methods follows long-standing practices. Use of the Basic Customer approach in the context of allocated distribution cost classification is unlikely to improve cost causation, given the non-correlation of customers' on-going fluctuations of maximum demand in a given year and their facilities capacity requirements. If the Commission wished for the Company to explore an alternative method for comparison purposes, albeit not explicitly endorsed by NARUC, I would recommend using class relationships comparable to the cost driver considered in the MCOSS.

- The Company's inclusion of primary lines in the MDS analysis is consistent with NARUC while recognizing that further segregation or sub-functionalization of primary conductors to main feeder and local primary taps would be an improvement if data were available.

- The 2019 MCOSS was updated to maintain alignment with the Company's forward-looking capacity conditions and customer characteristics and planning and the resulting estimates are consistent best practice marginal costing methods. Because the MCOSS estimates reflect cost causation, they are appropriate to assess the Company's rate proposals and future changes in time of use price signals.

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

A. Yes.