STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 24-070

REQUEST FOR CHANGE IN DISTRIBUTION RATES

REBUTTAL TESTIMONY OF

AMPARO NIETO

Allocated Cost of Service Study, Marginal Cost of Service Study and Rate Design

On behalf of the Public Service Company of New Hampshire

d/b/a Eversource Energy

March 10, 2025

Table of Contents

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and current position.

A. My name is Amparo Nieto. My current position is Principal at the Energy Practice of Charles River Associates (CRA).

Q. Please summarize your professional experience and education.

A. I am an economist with three decades of experience working in the energy industry and have extensively testified before state public utility commissions on marginal cost of service studies, electricity and natural gas rate design, avoided distribution costs, net energy metering, and allocated cost of service approaches in CA, AZ, IL, ME, MN, NH, NY, NV, ND, OR, SD and WI. I have also led cost of service analysis and provided recommendations for innovative rate design in Canada and internationally. I have a master's degree in Economics from Spain's Institute of Fiscal Studies and I received a BA in Economics from the Carlos III University in Madrid, Spain. Prior to working for CRA, I was Vice President in NERA Economic Consulting for two decades, then continued to hold leadership positions at other consulting firms. A copy of my Curriculum Vitae was attached as Attachment ES-ACOSS-1 of my direct testimony.

Q. On whose behalf are you testifying?

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

Q. Have you previously testified in this docket?

A. Yes. I submitted direct testimony on the Company's Allocated Cost of Service ("ACOS") study, and on the Marginal Cost of Service ("MCOS") study on behalf of PSNH in this rate case docket. My MCOS testimony also included recommendations on the appropriate use of marginal cost information in ratemaking for economic efficiency goals and to prevent cross-subsidization among customers within the rate.

Q. What is the purpose of your rebuttal testimony?

A. I provide rebuttal on specific issues raised by several intervenors, pertaining to the ACOS study and residential rate design. The witnesses are Caroline Palmer, who sponsored direct testimony on behalf of the Office of Consumer Advocate ("OCA"), Bradley Cebulko, who sponsored testimony on behalf of ARRP, and Mr. Clark, who sponsored testimony on behalf of the New Hampshire Department of Energy ("DOE").

My testimony is structured as follows:

- In Section II, I discuss specific comments from the intervenors on the ACOS study and their proposed use of an alternative distribution classification method.
- In Section III, I respond to issues of rate design in particular intervenors' opinions on the Company's basis to decide on an increase in the residential customer charge and the economic principles behind it, as it relates to basis for fixed charges, as well as appropriate time of use ("TOU") periods.

II. ALLOCATED COST OF SERVICE STUDY

Q. What are the main criticisms to the ACOS study by the intervenors?

A. OCA witness Ms. Palmer and ARRP witness Mr. Cebulko both take issue with the approach to classify certain categories of distribution plant in the ACOS study, and propose an alternative method. The Company's ACOS study relies on the use of the Minimum System ("MS") approach to breakdown each of the FERC accounts corresponding to poles, transformers, circuits and conductors (Accounts 364, 365, 366, 367 and 368 respectively) between customer-related and demand-related costs. An MS study identifies the minimum equipment size that the Company would have to install to connect a customer premise to the grid, for each plant category other than meters, and station plant. The smallest equipment size is identified and its cost represents the portion of the system cost that is incurred as a minimum when providing access to the grid, regardless of the specific customer's demand to be served. This piece represents the customer-related share of the plant. The balance of plant account is considered demand-related. OCA witness Palmer and ARRP witness Cebulko's positions are that the MS approach does not follow cost causation. In their view, no portion of the costs of distribution lines, poles or line transformer cost should be classified as customer-related and they claim that doing so unfairly increases the share of Company plant costs that get allocated to residential customers in the ACOS.

Q. What alternative classification method do OCA and AARP witnesses endorse?

A. The two witnesses support a method known as the "Basic Customer" approach. Under this approach, only meter (Account 370) and service laterals (Account 369) are considered to be driven by the number of customers in the class and allocated on the basis of relative customer numbers in each rate class. Any other distribution assets, including conductors and conduits (Acc. 365 - 367), poles, towers and fixtures (Acc. 364), and line transformers (Acc. 368), would be classified as 100 per cent demand-related and allocated accordingly. In comparison, the MS study adopted by the Company's ACOS study identifies customer and demand-related shares for each of these accounts. In particular, the MS method classifies as demand-related the following shares of gross plant: about 69 percent of overall lines and conductors (acc. 365, 366 and 367); 30 percent of overall line transformers (acc. 368), and 22 per cent of poles, towers and fixtures (acc. 364).[1]

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[1] The MS study was updated by the Company in 2024 for purposes of the 2024 rate case, except that the Company ACOS did not use updated values for Acc. 364 (poles) and Acc. 368 (transformers), due to unreliable data input for those accounts which produced biased results. This warranted the use of the MS study results that had been approved in the previous rate case.

Q. What impact would the Basic Customer price alternative have for the embedded cost allocations if adopted in lieu of the MS study

A. I tested the specific impact as part of the interrogatory phase of this Docket. The main implication of the Basic Customer method is that it shifts a larger share of plant costs to the commercial and industrial customers, due to the relatively higher per customer demand that commercial customers tend to have. The Residential customer class would get allocated about 15 percent less than the residential revenue requirement compared to the MS study. This result reflects an allocation of distribution plant entirely based on the ratio of residential class non-coincident peak demand (NCP) to total Class NCP summed across all customer classes.

Q. In your opinion, is the MS approach consistent with cost causation in an ACOS study?

A. Yes, because this classification method recognizes that distribution facilities are designed based on two key parameters: (a) how the equipment will be shared (customer numbers expected to be served downstream of those facilities) and (b) the long-term view of those customers' demands during the life of those facilities. The line transformers and conductors are intended to be one time investments, and expected not to have to be replaced as demand grows. They have a more local and fixed nature. The demand expectations reflect Company design standards, by type of customer in the class and determines the choice among given standard line transformer and conductor sizes. The MS study captures, while not in the same level of detail that a marginal facilities cost analysis in an MCOS does, the two key cost drivers for these investments. The customer component acknowledges that the growth in installations is largely driven by customer additions, while it also assigns a portion of the cost to classes on the basis of relative class demands to account for the impact of larger customers in higher than the minimum equipment size requirements.

Q. How would you summarize the conceptual shortcomings of the Basic Customer approach?

A. Simply put, the use of Basic Customer approach in an embedded cost allocation exercise is concerning as it means that all major distribution plant uses demand-related cost allocation, which breaks ties with actual planning and therefore weakens the conceptual justification. It ignores the role that discrete customer connection jobs have in investments that facilitate customer access to the grid, which represent a meaningful component of primary plant and all of the secondary plant accounts. Additionally, the method incorrectly presumes that actual demands is how the Company plans these assets. In reality, the Company field engineers use specific connection demand standards, not near-term or test-year actual customer demands. Class NCP is only loosely connected to what drives plant size requirements and therefore is even more problematic to allocate all lines on the basis of class demand. In contrast, the MS study is a superior approach to the Basic Customer approach by virtue of recognizing a minimum cost separately for circuits, poles and line transformers that is unrelated to actual variations in demand. This, in my view, is the main reason why the MS method has stronger precedent in ACOS studies in the industry as I will explain later on.

Q. Does the National Association of Regulatory Utility Commissioners ("NARUC") endorse the use of the minimum system approach?

A. Yes, the NARUC Electric Utility Cost Allocation Manual[2] recognizes the minimum system approach as one of the appropriate ACOS methods to determine classification of accounts 364 through 368. The NARUC Manual clearly states that each distribution plant account, 364 through 368, can be separately classified into a demand and customer component.[3] It also adds that: "*The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system*." The other method that NARUC describes for classification of these accounts is the "zero-intercept approach", which also identifies both a customer and a demand component for plant accounts 364 through 368. Although the NARUC Manual is intended to serve merely as a guide for cost of service studies, the Basic Customer Method that OCA and AARP witnesses recommend greatly departs from any of the ACOS methods described in the manual. The Company's ACOS study therefore adheres to the principles of cost causation as recommended in the NARUC's Manual, by using the concept of customer additions through the MS study. Distribution plant (FERC account 362 Station) is correctly classified as entirely demand-related because distribution substations serve much more diversified loads. For any plant other than substation and the

[2] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, Jan 20, 1992.

[3] See NARUC Electric Utility Cost Allocation Manual, January 20, 1992, Table 6-1 in page 87 and page 90.

trunkline primary feeder, investment decisions are largely driven by the numbers of customers served. Consistency with NARUC's methods has traditionally been favored by the Commission in NH. The only instance where the NARUC's Manual mentions a method similar to the Basic Customer approach is in the context of the Marginal Cost methods, and this is irrelevant to the discussion of what to use in an ACOS study for customer costs. The Basic Customer price method is scarcely adopted in ACOS studies across the country, due to not being recognized as being a strong method to reflect cost causation.

Q. How does the Company's MS study address the different demand drivers of plant?

A. In particular, transformer and local conductors are put in place based on design demand standards tied to every customer expected to connect. The MS is a reasonable classification method by designating a portion of the cost as customer-related, covering a minimum load that tends to be only a share of the average design demand. It is not uncommon that local facilities will be sized larger than strictly necessary to meet customer demands, due to a combination of economies of scale of the equipment,[4] and the Company's expectation that longer term, customer demand will be higher than current connected load, e.g., if there is electrification growth expected in the service territory. This effect is generally more notable in the case of residential connections. Transformer plant required per residential customer is actually larger than the average residential customer's actual demand, and therefore this method would lead to under-allocation of plant to the residential class. An allocator based

[4] This is particularly evident in the context of rural areas with predominance of single homes, given the standardized equipment sizes available to the Company.

on class NCP ratio would assign a higher weight to the small commercial class, given the higher demand per customer but this ignores higher utilization of line transformer, and the economies of scale of larger transformers.

Q. How widespread is the use of the MS study in ACOS studies in the U.S.?

A. Based on my review of ACOS studies across the country, both the minimum system study and the zero-intercept approach are the most prevalent ways to classify distribution plant accounts 364 through 368. In some instances, both methods are conducted, and the Company may use a combination of both, such as in MN. Examples of U.S. utilities where a MS study is used include Alabama Power (AL), Georgia Power Company (GA), Central Hudson Electric & Gas (NY), Central Maine Power (ME), Choctawhatchee Electric Cooperative (FL), Con Edison (NY), 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), and Carolina Power & Light (NC). In Canada, the use of an MS study is also common, and examples include ATCO, New Brunswick Power Corporation, Newfoundland Power, Hydro One and Hydro Quebec. I have observed that a number of these utilities apply the MS study only to poles, line transformer and secondary wires, and not to primary lines. In contrast, the Basic Customer method that the witnesses from OCA and AARP propose and that ignore the concept of customer additions as a explicit cost diver is scarcely applied. It tends to be more in the context of a marginal cost study where the study separates out marginal facilities cost from customer marginal cost.

In addition, I have observed that where the Basic Customer method is adopted in embedded cost studies, the cost of the transformer (Account 368) is sometimes classified as customer-related costs (e.g., in Iowa), contrary to the version endorsed by the OCA and AARP witnesses.

Q. Is the OCA witness example to attempt to prove that 100% demand classification warranted for all distribution plant other than meter and service lateral valid?

A. Ms. Palmer attempts to demonstrate that applying 100% of demand related allocators to all distribution accounts 364- 368 reflects cost causation, with a scenario where a new customer is added to the grid already in place (transformer, poles, conductors) and it does not make the Company incur in any incremental plant (distribution system upgrades). The reason is that the new customer does not increase the capacity requirement on the existing distribution system. In her view, this demonstrates that distribution plant is driven by demand additions, rather than by the number of customers added. In other words, OCA witness' position is predicated on the notion that only when a customer addition requires investment *in all real-life scenarios*, such asset type can be considered customer-related. The logic here is flawed. Even if no upgrade of lines or transformers occurs as the new customer connects to the grid, in many cases, the Company investment *was* made with that new customer in mind.

Q. Please explain why Ms. Palmer's logic is flawed.

A. I can illustrate my point with a couple of scenarios. In one scenario, the customer is coming into a home that was already connected to the grid to serve the previous owner, and the customer simply makes use of the existing capacity dedicated to the home. This is a customer-related connection, simply the asset cost allocation swaps from one customer to another. In a second scenario, the new customer comes into a home not already connected to the distribution grid but the connection does not require an expansion of the local line transformer. It may be the case that when the transformer was installed for the initial customer(s), the Company assumed it was likely that additional customers or homes would be connected to the system in the future and sized the transformer accordingly. This is typical practice in a new residential subdivision. The Company expects that new residents will commence taking service at a later date, and the overall customer numbers is usually accounted for in sizing the facilities.

Q. Is it likely that customer additions do not require investment in the Company's service area?

A. The Company's distribution field engineers work with standardized secondary line transformers and conductors. The Company's service areas tend to be largely rural and as a result transformers are not extensively shared for residential class. It is possible that a residential home is responsible for the entire capacity of a transformer (and line) until a new customer comes along, while a customer in an urban area, regardless of whether both customers have the same expected maximum demands, A customer may be in a location far from the grid and require a line extension. The line extension policy may require charging the customer a Contribution in Aid of Construction (CIAC), but the customer may receive a reimbursement later on if new customers connect to that extension. In all these scenarios, it is clear that the new customer addition needs to be accounted for in cost allocation, even when customer addition does not require expanding the original investment every time a customer requires connection. It generally means that future customers are accounted for when deciding the required size of the original investment. Finally, when a customer joins with a larger than typical connected residential customer load, this may trigger an upgrade or a whole new separate transformer, and this is a function of both a customer addition and growth in design demand-related cost. This extra cost related to meeting demand larger than minimum or typical customer size is what the demand-related share calculated by the minimum system study attempts to capture. In other words, the portion of the total costs in each account, assumed to provide capacity to meet the full customers' peak load requirements beyond minimum requirements, is represented by the demand-share of the MS study.

Q. What other alternative approach other than her preferred method of Basic Customer would witness Palmer recommend?

A. In lieu of the Basic Customer approach, witness Palmer would find acceptable a hybrid classification method that classifies all primary distribution lines as 100 percent of demand related, while the MS methodology would apply only to the secondary voltage lines. This hybrid method has precedent, although it is not as common as the Company's approach used in this proceeding which applies MS to all lines.

Q. What do you think about this alternative?

A. The problem with an approach that classifies primary plant as entirely demand-related is that from a cost driver perspective, only a portion of the primary lines, representing the trunkline primary feeders, are purely peak demand-related. These more upstream lines typically with a voltage level of 46 kV or 34.5 kV, serve highly diversified demands. The remaining primary lines in accounts 365-366-367 are more likely to be the segment of the primary line downstream of the trunkline feeder that branches out to serves specific customer areas and driven partly by customer-specific design demands. Thus, witness Palmer's proposed hybrid method ignores the more local nature of the demand served.

Q. What difference would it make in residential cost allocation to exclude primary lines from the MS study?

A. I tested the impact of this hybrid approach as part of the intervenor's interrogatory phase in this docket and it results in a relatively moderate difference; it would reduce allocation of revenue requirement to the residential class by about 11 percent. It is also worthy to note that in the Company ACOS study filed, a high share of the primary lines in accounts 365-367 is already classified as demand-related using the MS study, which explains the small impact. Specifically, the overhead primary line (Acc 365) is 69% demand related. This percentage is even higher for the underground primary lines (Acc. 366 & 367), where 93.7 percent of polyphase and 84.7 percent of single-phase lines are demand-related.[5] The

[5] In developing the ACOS factors, I took the results of the Company minimum system study for overhead and underground conductors and for line transformers and poles, and I further recomputed the factors for underground primary lines to distinguish between single and polyphase lines, using available information from the study.

ACOS study filed by the Company already assigns a higher cost to the primary lines to demand indirectly through the separate classification of single vs. polyphase lines for at least the underground segment. In the ACOS study, I employed separate 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 and to avoid allocating single phase to polyphase customers.

III. RATE DESIGN AND MARGINAL COST BASIS FOR FIXED CHARGE

Q. How do OCA and AARP witnesses propose to use the Basic Customer approach in rate design?

A. Witnesses from OCA and AARP argue that the only costs that belong in the fixed charges are exclusively the embedded costs of meter, service drop, plus customer-related account and informational services, consistent with their preferred Basic Customer approach. This would mean a customer charge of only $13.52 per month for the Residential class, much lower than the optimal customer charge. The problem with this rate design approach is that it is not supported by economic theory, as it does not keep into account the impact of price signals on customer’s behavior or marginal cost price results.

Q. Please explain if the Company proposes using the full ACOS customer cost or marginal customer costs for rate design.

A. No. The residential customer-related unit cost under the Company's ACOS method is $40.93. In the MCOS study, the sum of monthly marginal customer and marginal local distribution facilities costs estimated for the average residential customer is $42.90 (based on the sum of $18.14 for customer marginal costs and $24.76 for facilities). The Company is not currently proposing a monthly residential fixed charge based on either of these full cost-based levels, but it proposes to rise the charge for Rates R and R WH to a level of \$19.81. The Company arrives to this level by capping the customer charge at the overall Company revenue requirement percent increase to reduce differences the marginal customer cost. This proposed charge is still a fraction of either the fully ACOS customer-related cost-based charge, and the full marginal customer plus facilities cost level. It is however, a step in the right direction and more cost-reflective than the current fixed charge level of \$13.81. I agree with increasing the fixed charge gradually rather than inputting any rate increase to the energy charges of the residential rate, which would only exacerbate the cross intra-class subsidies. This method at least ensures that the Company's proposed residential fixed charge allows to recover no less than the marginal customer-based cost of the meter, service drop and customer-related service expenses, and includes a portion of the monthly marginal per-customer distribution facilities costs. This proposal also prevents potential steep customer bill impacts that might result from bringing the customer charge to recover fully the marginal facilities costs for the typical residential customer. I find this approach is conducive to higher equity and efficiency in residential distribution rates and I would recommend that the monthly fixed charges continues to gradually increase in future rate cases towards customer and facilities costs.

Q. What is in your opinion the risk of using the Basic Customer method to set customer charges?

A. The Basic Customer approach would erroneously reduce the monthly customer cost below the true level of cost that are fixed in nature. An artificially low customer charge leads to price signals that encourage suboptimal adoption of Distributed Energy Resources (DERs) and produces cross-subsidies between high and low energy users within the class. This is more clearly the case when the tariff has a two-part rate structure, meaning it only has a customer charge and an energy charge. A customer charge limited to those costs categories results in energy charges that over-recover costs, unrelated to the costs that customers impose when using more kWh of electricity on the grid. Customers will see an overestimated incentive to conserve or to adopt distributed PV generation, which is inefficient because when a customer reduces energy, the net revenue loss is unmatched by any avoided costs realized by the Company. This is particularly true in radial networks, where there is little opportunity to share capacity of the line transformer with other customers, from customer demand reductions. Other customers will shoulder the net revenue loss at the time of the next rate case. Inefficient pricing of electric service can drive customers to change their behavior in a way that has no value to the system, and/or pursue technology alternatives that do not provide distribution benefits, it merely shifts costs to other customers. Marginal cost results are more appropriate to set the basis to decide on the relative floor levels for the fixed monthly charge and volumetric charges.

Q. Would you be supportive of using the Basic Customer approach as the basis to set the level of monthly fixed charge if the rate structure included a demand charge?

A. Applying the Basic Customer approach is less distortionary when rates include a demand charge component, but even then, there may be an artificially high price signal in metered demand charges that does not guarantee better alignment of costs and rates or economic efficiency. This is because bill changes that may occur month to month when customer monthly maximum demand changes are not a fair representation of how the underlying costs of local facilities service change. The size of the transformers required to serve the customer remain the same, because it needs sufficient capacity to accommodate longer-term higher loads. Contract demand charges would be a more optimal rate component for the local facilities. This would still not justify setting customer charge equal to the ACOS customer-related costs. Marginal customer costs, in today's dollars, would be the floor level of this rate, along with any facilities cost components not recovered in the subscription or demand charge.

Q. Do other intervenors have comments on the Company's rate design proposal that you would like to respond to?

A. Yes. I would like to respond to intervenor from the NH DOE, witness Michael Ty Clark regarding some of his rate design comments, mostly with regards to time of use ("TOU") rates. His testimony includes the following recommendations: (a) adjustments to TOD periods and prices to better reflect marginal cost drivers, b) introducing seasonal TOD period with the peak period occurring only during months June 4 through September (or alternatively July through August); c) a TOD peak period of 2 to 8 p.m. weekdays, excluding holidays, for residential and all commercial TOD rate; d) update the peak and off-peak prices for TOD rates (R-OTOD2, G-OTOD, LG) using MCOS study results that allocate time-differentiated marginal costs to the recommended TOD periods with the Probability of Peak ("PoP") analysis.

Q. What do you think about DOE's witness Mr. Clark's positions?

A. There are many areas in Mr. Clark's testimony where I agree with his position, including that ideally TOD periods will shift to later in the afternoon as demonstrated in my MCOS study. Mr. Clark clearly recognizes the importance of marginal cost information in rate design and setting not just TOD periods but also fixed charges. He does not oppose the Company's proposed fixed charge increases, though he recommends a more aggressive increase to the fixed charge of the Residential TOD rate to ensure full recovery of marginal customer costs as a minimum in this rate case. Overall, witness Clark agrees with the principles I stated in my direct testimony of using the results of the underlying marginal cost by time of day and season in proposing changes to TOD rates. He does disagree with the Company's proposed continuation of year-round rates for TOD and recommends introducing seasonal rates. This would avoid diluting the peak to off-peak marginal cost differentials in the summer months. Witness Clark also recommends only using a peak period during the summer season, which is consistent with the results of the probability of peak analysis that I conducted as part of the MCOS study, which revealed that 90 percent of the probability of peak is concentrated in the summer months and particularly so in hours 2 pm to 7pm within the peak period.

I agree with witness Clark that TOD price differentials are an important factor when customers decide to shift load to off-peak hours and seasonality in rates would be more cost-reflective than year-round. At the same time, I would recommend that once the cost-benefit of implementing seasonal rates is established, the Company may want to preserve keeping two TOD periods in all months in anticipation of further electrification and to signal higher potential incremental cost in late afternoon and evening hours as more substations are utilized, yet with a lower peak price on the non-summer months. Ideally the Company would use three seasons to target the coldest winter months. I believe that the price differential under a two or three-season construct would still be relatively moderate, and therefore the Company may have weighted the cost of implementing changes in its billing system with introducing seasonal rate design changes at this point. The benefits would be larger if not only distribution costs can be time-differentiated but also transmission and generation costs. I would propose the Company to consider seasonally-differentiated demand charges as an optional rate to experiment in a later rate case or for electrification purposes to provide stronger price signals.

Q. What is your opinion regarding witness Clark's proposal in setting TOD price differentials?

A. Mr. Clark appears to propose to base the TOD price differentials on TOD marginal cost 'ratios'. The Company instead relies on the "price differentials" among marginal costs, based upon my recommendation of using absolute price differentials and not MC ratios by time of day. The reason why the Company's position to reflect the absolute price differentials is more conducive to efficient rates is that they allow to reflect how much the Company can save in terms of avoiding capacity expansion when the customer switches 1 kW from a peak hour to an off-peak hour. It is better alignment of the grid cost impact of incremental usage with the price signal the customer receives and this is the condition for economically efficient decisions regarding usage but also adoption of DERs. Using TOD MC ratios instead of price differentials has the effect of re-allocating sunk costs in proportion to marginal cost, which is important at the time of re-setting rates for a given class, but it is not efficient in between rate cases as the bill change the customer experiences bears no relationship with the true marginal cost impact. For example, the peak to off-peak marginal cost is 22, but the avoided cost from 1 kW reduction is not 22 times the on-peak price, rather it is just the on peak marginal unit cost. While peak to off peak price differentials may be lower than what the customer would rather see as a stronger incentive to shift load, marginal cost price differentials do a better job at setting the correct incentives plus avoiding equity issues when customers adopt energy efficiency or a distributed energy resource.

Q. Does this conclude your testimony?

A. Yes, it does.