STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 16-576

DEVELOPMENT OF NEW ALTERNATIVE NET METERING TARIFFS AND/OR OTHER REGULATORY MECHANISMS AND TARIFFS FOR CUSTOMER-GENERATORS

REBUTTAL TESTIMONY OF RICHARD C. LABRECQUE, RUSSEL JOHNSON, AND EDWARD A. DAVIS

DECEMBER 21, 2016

I. INTRODUCTION

Q. Mr. Labrecque, please state your name, position and business address.

A. My name is Richard C. Labrecque. My business address is Eversource Energy, Energy Park, 780 North Commercial Street, Manchester, New Hampshire. I am the Manager of Distributed Generation (NH) for Eversource.

Q. Mr. Johnson, please state your name, position and business address.

A. My name is Russel Johnson. My business address is Eversource Energy, Energy Park, 780 North Commercial Street, Manchester, New Hampshire. I am employed by Eversource Energy Service Company as Manager - System Planning.

Q. Mr. Davis, please state your name, position and business address.

A. My name is Edward A. Davis. My title is Director of Rates for Eversource Energy Service Company ("Eversource" or the "Company"), and my business address is Eversource Energy, 107 Selden Street, Berlin, CT 06037.

Q. Did each of you submit direct testimony in this proceeding?

A. Yes. We submitted testimony on October 24, 2016 in this proceeding and our qualifications and experience are set out in that testimony.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to comment upon the various proposals and rate mechanisms that parties have advocated in this proceeding. Given the volume of material filed, direct replies to all points would be impossible. Therefore, we concentrate mostly on certain themes and recurring issues presented by various parties in initial testimony submitted in this docket that the Company wishes to address. The order of these topics is as follows: Cost Shifting and DG Compensation, Valuation Proposals of Other Parties, and Rate Design.

Q. What is your overall position having now reviewed the proposals in the docket?

A. Based upon review of numerous proposals and analyses in the docket, we have not seen anything that causes us to change our primary positions in this case. Net Energy Metering ("NEM") for distributed generation ("DG"), as it presently exists in New Hampshire, allows individual customers to avoid paying for services they receive and creates an unfair shift in the recovery of costs, from participating customers to non-participants. The design of delivery rates for DG customers and compensation for excess power should both change to eliminate or reduce that shift and assure appropriate utility cost recovery from customers who use these services. Also, while there were a number of proposals in the docket relative to rate design for NEM customers, we have not seen anything that demonstrates that Eversource's proposed rate design for NEM customers is unjust, unfair, or improper.

Q. Also as an initial matter, have parties suggested that the current net metering program capacity limit of 100 MW is "out of step" with surrounding states?

A. Yes, see testimony of Ms. Kate Bashford Espen on behalf of NHSEA (page 7, footnote 6). Eversource disagrees with the specific statement that the 100 MW program "represents about 2-3% of the utilities' peak load in New Hampshire". Based on data from ISO-NE, the 2015 peak demand in New Hampshire was 2223 MW. The 100 MW program is therefore larger than claimed, and represents 4.5%, not 2-3%, of this peak demand. Further, Eversource believes that a state's net metering program should be evaluated in its' entirety, not just from the perspective of the program capacity limit. In the 2015 edition of "Freeing The Grid – Best Practices in State Net Metering Policies and Interconnection Procedures" (see www.freeingthegrid.org), New Hampshire was one of twenty states whose overall program design earned the highest grade ("A").

II. COST SHIFTING AND DG COMPENSATION

Q. You mentioned that there is a cost shift, could you explain the cost shift issue in greater detail?

A. As described in Eversource's initial testimony, utility rates are set with the intent of allowing a utility to collect its revenue requirement, which includes the costs to design, build, own, operate and maintain the electric distribution system safely and reliably. Since the Company's current delivery rates for residential and small general service customers are based largely on volumetric (kWh-based) charges, net metered customers avoid paying their share of fixed delivery costs by reducing their volumetric purchases from the grid and through the netting of excess energy. Thus, the utility does not collect sufficient revenue from these customers to cover the cost to serve these customers. Absent a change to the delivery rates charged to net metered customers, to meet its revenue requirement, a utility would need to raise rates to all customers. Even so, increased rates would still be avoided by net metered customers under the current rate design, pushing more costs for recovery to non-participating customers. Additionally, power exported to the grid is compensated at the full retail rate, which is higher than the market value of that energy. These two mechanisms create a shift of costs.

Arguments and positions presented in the testimony submitted by various parties focused on presenting NEM customers as providing some measure of "value" to the utility system and, further, that the value provided appropriately offsets the cost. Eversource sees those as separate, but related, issues. Under NEM currently, there is a shift of fixed utility costs that has little, if anything, to do with the "value" of DG. Also, the value measures in the testimony appeared to selectively include or exclude various costs or benefits, or rely on benefits that seemed speculative or difficult to quantify, and, in the end, ascribed too much value to the DG. The result of combining the unrecognized shift of actual, realized costs with overinflated values masks the concerns we have raised and fails to ensure that NEM customers pay for the infrastructure they use and rely upon and fails to protect non-participating customers from bearing greater costs than they should.

Q. Could you elaborate on the "fixed utility costs" you mentioned?

A. Yes. The utility incurs costs to build, operate, and maintain the electric delivery infrastructure for the benefit of all customers. Those costs include things like poles, wires, trucks, meters, information systems, line workers, customer service, data handling, processing and billing, and numerous other capital and non-capital items. The vast majority of these delivery infrastructure costs are fixed; i.e. they do not fluctuate as the volume of energy delivered to customers increases or decreases. These costs will be incurred if there are no DG customers or if there are thousands. For an individual customer who installs solar (for example), the existence of solar on the roof does not make those fixed infrastructure costs vanish. Unless a customer completely disconnects from the utility grid, the customer makes use of the utility system and should be required to contribute fairly to the recovery of those costs.

Q. Are you saying that those fixed costs are not being recovered now?

A. In part, they are not. Under NEM, at present, the reduction in charges and effective rebates to NEM customers are structured in a way that those costs are not fully recovered. If a customer draws 350 kWh from the grid and pushes 350 kWh of excess generation through the grid in a given billing cycle, it is clear that the customer used the grid both for taking power and for selling excess power. However, under current volumetric delivery rates and NEM compensation, this customer would only be responsible for the customer charge, which is insufficient to cover the costs related to service provided to this customer.

Q. Is there any argument that DG customers are actually paying for those costs?

A. Some such arguments have been made, but they do not withstand scrutiny. For example, in testimony for The Alliance for Solar Choice ("TASC"), Mr. Beach states, at pages 13-16, that a NEM customer pays the full cost of the infrastructure because the customer is charged for the energy he or she imports and that the fact that a customer may have a "small, zero, or even net credit bill" does not mean that the customer has not paid for the use of the utility system. Such an argument defies simple logic. If a NEM customer sends power to the grid, the grid must regulate voltage, transfer the power to where it will be consumed without compromising the reliable operation of the electric system, and safely deliver that power to an end consumer. Likewise, if that customer imports power, the customer will need power that meets all the requirements for safe delivery and use of the power. Furthermore, these transactions occur at different levels and at different times.

Under Mr. Beach's analysis, a NEM customer could receive a bill for zero dollars in month after month after month, for years, and still be said to have paid for using the utility system. That customer will, during the period of zero billing, be regularly using the utility system to export power when the DG output exceeds use, and importing power when it does not. Also, even if the customer's DG production exactly matches its use during a given hour, the customer would still be using the utility system to provide voltage regulation, frequency support, motor starting amps, and other electrical needs. It is simply wrong to argue that a DG customer who pays nothing may be said to fully contribute to the recovery of costs for the system they use for both buying and selling electricity. In fact, Mr. Beach seems to acknowledge this reality when he states (at page 14) that "The utility is fully compensated for this distribution service when other customers (including the neighbors) pay the retail rate to have this [DG] power delivered to them."

In the testimony, and in response to discovery, Mr. Beach indicated that the appearance of a DG customer as not paying is simply the result of the accounting transaction of where the imported and exported power are netted. This explanation serves to highlight the issue raised above. The costs of the system and the need to recover those costs are related to, but not dependent upon, the compensation paid for DG power. At present, those issues are intertwined and masked within the NEM rate construct, leading to the result that DG customers, in fact, pay less than the costs they impose on the utility system, and that because of this, other customers must make up for DG customers' insufficient contribution for their use of the system.

Q. Are there costs other than those for the "utility system" that are also not paid for under the current system?

A. Yes. The system we were referring to above is the utility distribution system, and the costs related to that system. There are, however, other costs, such as transmission, the System Benefits Charge, the Stranded Cost Recovery Charge, and the Electricity Consumption Tax that are also being credited to DG customers. This creates an additional cost shift. For example, the Stranded Cost Recovery Charge is, by law, non-bypassable, and yet DG customers can "bypass" it by receiving a credit for it. Since the costs underlying that charge do not change depending upon the number or type of customers, it means that every dollar credited to NEM customers is one that must be paid by others. The result is another shift of costs that has no relation to any "value" the DG production might provide. In the end, it is clear that the full retail rate credit is not the appropriate level of compensation because it credits items that should not be credited, and even CLF (Testimony of Paul Chernick at 27-28), TASC (Testimony of Thomas Beach at 36), and OCA (Testimony of Lon Huber at 22-23) acknowledge as much.

III. <u>VALUATION PROPOSALS OF EVERSOURCE AND OTHER PARTIES</u>

Q. Regarding the appropriate level of compensation for the power produced by DG, please summarize the Company's position.

A. For all DG production that is consumed internal to the customer's property (i.e. DG production that reduces the instantaneous level of power consumption) the customer would avoid paying all volumetric rate elements. Since Eversource's proposal converts transmission and distribution delivery charges to a demand-based rate, the remaining volumetric charges are: Energy Service, Stranded Costs, Systems Benefits, and the

Electricity Consumption Tax. Under currently effective residential rates, those charges sum to 11.43 cents/kWh (assuming the customer is taking Default Energy Service).

For all DG production that is exported from the customer's property (i.e. power that exceeds the instantaneous level of internal power consumption), the Eversource proposal would provide a bill credit at the Default Energy Service (DE) rate. This compensation rate only applies up to the level of purchases in that billing cycle. The current DE rate is 10.95 cents/kWh.

To the extent that exported DG production exceeds the quantity of power purchased during the billing cycle (i.e. the quantity of power imported into the property), that excess would earn a bill credit at the monthly avoided cost rate. Eversource proposes using a monthly rate methodology that mimics the annual avoided cost methodology in rule Puc 900 for this purpose. The most recent average annual rate based on this methodology is approximately 3.47 cents/kWh for PV resources.

To illustrate Eversource's proposed three tiered compensation structure, assume that 50% of the production from a customer-sited PV facility is consumed internal to the host property. Of the 50% that is exported, assume that 75% is matched with internal consumption in the billing cycle (and payable at the DE rate) and the remaining 25% is excess (and payable at the avoided cost rate). Under these illustrative proportions, and with current rates, the average valuation of the PV production would be 10.26 cents/kWh.

Q. How does your illustrative example above (10.26 cents/kWh) compare to the value of the power in the ISO-NE wholesale market?

A. Please refer to the previously filed testimony of Labrecque & Johnson (page 19 and 20) for a representative analysis of the wholesale value of PV power in the ISO-NE energy and capacity markets during 2015. The 10.26 cents/kWh is approximately 2.3 times the average wholesale value of PV power (4.461 cent/kWh) based on that analysis. Relative to the Puc 900 avoided cost rate for 2015 (3.47 cents/kWh), the 10.26 cents/kWh valuation is a multiple of 2.96, or roughly triple the actual wholesale rate for such power.

Q. In the recently published manual - National Association of Regulatory Utility Commissioners (NARUC) Distributed Energy Resources Rate Design and Compensation (November 2016) – is there a discussion of the use of the wholesale locational marginal price (LMP) as a compensation mechanism for DER?

A. Yes. In a section related to "Restructured Jurisdictions" (such as ISO-NE), the following statements appear:

[Page 87] - While it can be argued that compensating the energy portion of net positive NEM production at retail rates is appropriate, most observers would say that the true value of such energy is "as available energy" and should be compensated as such, which in most restructured jurisdictions is the LMP.

[Page 88] - For generation in a restructured market, regulators may want to consider a variety of options, including, but not limited to, the following:

• Compensate net energy production at LMP (on a monthly or daily basis).

Q. How does Eversource distinguish its proposal to compensate DG resources from the guidance provided by NARUC?

A. Eversource recognizes that a DG compensation structure based strictly on current wholesale market prices is too volatile, too uncertain, and most significantly, too low to promote the continued, steady growth of the New Hampshire market for solar and other forms of DG. Eversource believes that its proposal is a fair balance that continues to provide a reasonable opportunity for customers to invest in DG consistent with HB 1116.

Q. Have other parties in this docket offered DG valuation proposals?

A. In this docket, like in many others across the United States, participants have submitted a range of valuation analyses, often called "Value of Solar" (VOS) or "Value of Resource" (VOR) methodologies. Because Mr. Beach's methodology was used in his own analysis for TASC, and that of EFCA and NHSEA, Eversource provides the following rebuttal to the methodology offered by Mr. Beach. As noted above, Eversource has elected not to provide specific rebuttal to each and every valuation proposal filed in this docket, and considers the rebuttal below representative of the Company's general concerns.

Q. Please describe your concerns with the valuation submitted by Mr. Beach.

A. At a high level, consider the table below, which is reproduced from Table D-12 from the Beach testimony. Under his analysis, the total valuation for solar is 30.35 cents/kWh.

Summary of Solar DG Benefits (25-year levelized $/MWh)		
		Eversource
Direct Benefits	Energy	63.3
	Generation Capacity	65.6
	Generation Capacity Reserves	9.4
	Solar Integration / Admin Costs	(5.0)
	ISO-NE Transmission Capacity	19.6
	Market Price Response (DRIPE)	2.8
	Avoided Fuel Cost Uncertainty	27.4
	Distribution	22.5
Societal Benefits	Carbon	23.4
	SOx and NOx	36.6
	Local Economy Benefits	38.2
Total Benefits	**Direct**	**205.6**
	Societal	**97.9**
	Total	**303.5**

Q. Which of the listed items are recognized by and captured in the ISO-NE competitive wholesale market structure by which generation resources in New England are compensated?

A. Generation resources can participate in the energy market and the forward capacity market. Certain resources are also able to participate in certain ancillary service markets. Of the items listed above, the following are consistent with the ISO-NE market structure.

Energy	63.3
Generation Capacity	65.6
Generation Capacity Reserves	9.4
Total	138.4

Q. Are any of the other listed items captured within the ISO-NE market compensation structures?

A. Yes. In New England, the cost of compliance with CO2 regulation (RGGI), as well as SOX and NOX requirements are borne by the owners of generation resources that emit these pollutants. Generation owners recover these compliance costs via the ISO-NE energy market, i.e. the cost of emission credits and allowances is reflected in the energy offer prices of those generators. Mr. Beach acknowledges these facts in his responses to Eversource discovery questions 1-31 and 1-32.[1] Thus, the following represent the subtotal of items from Mr. Beach's Table D-12 that are included in the ISO-NE wholesale markets:

Energy	63.3
Generation Capacity	65.6
Generation Capacity Reserves	9.4
Carbon	23.4
SOx and NOx	36.6
Total	198.4

Q. How do the elements of value in the above subtotal compare to the value of PV resources in the ISO-NE markets during 2015?

A. The subtotal above (19.84 cents/kWh) is roughly 4.5 times the ISO-NE wholesale rate of 4.461 cents/kWh detailed in the previously filed testimony of Labrecque & Johnson (page 19 and 20).

Q. In Table D-12 of Mr. Beach's testimony, what value items are reflected in the Default Energy Service rate?

A. In his response to Eversource discovery question 1-30, Mr. Beach stated that "the benefit categories corresponding to default energy service are avoided energy, emissions, and generation capacity, adjusted for losses."

In addition to the items acknowledged by Mr. Beach, the Default Energy Service rate also includes the benefit category Mr. Beach refers to as "Avoided Fuel Cost Uncertainty".

[1] Discovery responses referenced in this testimony are reproduced in Appendix A.

According to Mr. Beach's testimony (page D-6) this category recognizes "the exposure of New Hampshire ratepayers to the future uncertainty and volatility in natural gas prices". In his response to Eversource discovery question 1-33 he provided the following comments:

"Fuel hedging would be done by primarily market participants that have fuel costs. Those costs are passed through to all types of market participants, e.g. a load serving entity's avoided costs would be affected. A load-serving entity that hedges its costs in the electric market may be engaging in fuel hedging indirectly".

The benefit category items that are reflected in the Default Energy Service rate are identified below:

Energy	63.3
Generation Capacity	65.6
Generation Capacity Reserves	9.4
Carbon	23.4
SOx and NOx	36.6
Avoided Fuel Cost Uncertainty	27.4
Total	225.8

Q. How do the elements of value in the above subtotal compare to the current Eversource Default Service rate?

A. The subtotal above (22.58 cents/kWh) is approximately double the current Eversource Default Service rate (10.95 cents/kWh).

Q. Should DG be compensated at a rate that is more than twice the Default Service rate?

A. First, it must be noted that the grand total of Mr. Beach's benefit analysis (Table D-12) is 30.35 cents/kWh. But even if one focuses only on the items above (that total 22.58 cents/kWh), it is difficult to find justification for valuing intermittent, non-dispatchable generation resources at more than double the rate for Default Energy Service, which is a firm, full-requirements, fixed price, load following retail service. The differences between intermittent DG power and a retail energy service product are further detailed in the previously filed testimony of Eversource witnesses Labrecque & Johnson (pages 14 - 16).

Q. Please comment on the benefit category Mr. Beach refers to as "Local Economic Benefits," to which he assigns a value of 3.82 cents/kWh.

A. To the extent this is even an appropriate category of benefits to include, the quantification of the value for this item is overstated. Mr. Beach (on page D-10) makes an argument that "a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – is spent in the local economy, and thus provides a local economic benefit in close proximity to where the DG is located." While there may be an element of truth to that assertion, the local benefit of DG should only be considered relative to the local benefit of other options that would be implemented in the absence of DG.

Refer to Mr. Beach's response to Eversource discovery question 1-64 (pasted below):

REQUEST:
In Tables D-12 you include $38.24 $/MWh as a societal benefit based on your estimated "total local soft costs" (from Tables D-9 and D-10). Have you determined and quantified the equivalent societal benefit of non-DG alternatives? Has the $38.24 been reduced such that it only reflects the incremental benefit of DG vs. non-DG?

TASC RESPONSE:
No, we have not quantified the equivalent societal benefit of non-DG alternatives, although those alternative benefits may be zero if the alternative resources are not built in New Hampshire. See response to Eversource 1-63.

In that Mr. Beach appears not to have attempted to quantify any local benefits of non-DG alternatives, and that he appears to have simply assumed that either there are no such benefits or that if they exist they must be zero, this assignment of value here is questionable.

Q. Referring again to Table D-12 in Mr. Beach's testimony, what value does he ascribe to "Societal Benefits"?

A. The "Societal" benefit categories are reproduced below.

Carbon	23.4
SOx and NOx	36.6
Local Economy Benefits	38.2
Total	98.3

Q. Should these "Societal" benefits be considered in designing a replacement net metering tariff?

A. There are other types of programs (i.e. the federal Investment Tax Credit, state grants and rebates, RECs and tax exemptions) that exist to encourage DG and that can be, and are currently, used to compensate DG for societal benefits. Please refer to Eversource's previously filed testimony of Labrecque & Johnson (page 28) in which the topic of double-counting of benefits is discussed. Also, Eversource provides the following excerpt from pages 135 & 136 of the National Association of Regulatory Utility Commissioners (NARUC) final publication of its manual, *Distributed Energy Resources Rate Design and Compensation (November 2016)*.

One must use caution, however, to ensure that any value component determined by the VOR is not already being tracked or traded separately. For example, in Nevada, renewable DG is eligible for RECs and customer generators are granted credits based on system output. However, a greater number of RECs are given if the system is a distributed energy system, so the value of the avoided distribution would be counted twice if valued both as a REC and as a component of a VOR payment. Also, if environmental credits and benefits (such as environmental costs, avoided CO2, and avoided pollutants) are separately tracked through issuance of RECs through a recognized tracking *mechanism, one should remove them from the VOR list, or else those same benefits or avoided costs would be double counted. Determinations of value should attempt to reflect the actual, market value of a trait as identified and valued by that jurisdiction. In this instance, a value for carbon avoidance should be based on market value, and should avoid alternative, non-market-based values.*

Q. In the above quote from the NARUC manual, it says attempts to value certain benefits should "reflect the actual, market value of a trait as identified and valued by that jurisdiction". The quote specifically refers to the valuation of carbon avoidance as an example. How is carbon avoidance valued in ISO-NE and how did Mr. Beach value carbon avoidance?

A. New Hampshire participates in the RGGI program. Based on the work papers provided by Mr. Beach in response to discovery, the average RGGI auction price in 2015 was \$6.11 per short ton and the average auction price to date in 2016 was \$4.77 per short ton. In his valuation of CO2 avoidance, Mr. Beach opted to use a starting value of \$45.24 per short ton, which is based on the EPA study of the social cost of carbon [see footnote 15 of Mr. Beach's testimony on page D-10, which references *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)*]. Mr. Beach subtracted his forecast of future RGGI auction prices from his forecast of the future societal cost of carbon to ultimately derive the value on \$23.23 per MWh in his Table D-12. In summary, Mr. Beach has relied on a non-market-based valuation technique that is much higher than the market-based value used in the RGGI program (which is already factored into ISO-NE energy prices).

Q. Could you comment on the benefit category Mr. Beach refers to as "ISO-NE Transmission Capacity", to which he assigns a value of 1.958 cents/kWh?

A. Mr. Beach states that "solar DG will avoid transmission costs to the extent that solar production occurs during the peak demand periods that drive transmission costs". That statement only scratches the surface of the issue.

To evaluate the appropriateness of compensating a particular DG resource (or class of resources) for the avoidance of transmission expenses, a complete and quantitative assessment of numerous factors, including the following, would be required:

Coincidence with peak demand

Mr. Beach's analysis (Table D-4) concludes that, on average, the production from a PV facility will be at 17.6% of the PV nameplate capacity during the 12 monthly coincident system peaks which are used to allocate transmission revenue requirements.

Reliability of the demand reduction

For example, of a representative aggregate portfolio of DG resources of 50 MWs, Mr. Beach's analysis would suggest that an average value of 17.6% (or 8.80 MW) be assigned to this portfolio. That analysis assumes much about how those resources would actually operate. Are any DG-based demand reductions in a particular region of the grid sustainable and permanent? Is it possible that if this aggregated portfolio of 50 MWs of DG resources was in the seacoast region of NH, it might provide 20 MWs of demand reduction during the peak load hour in the summer of 2017, but only 5 MWs in the summer of 2018? Perhaps the peak hour in 2018 will be during a hot, humid, but cloudy afternoon. It would not be considered prudent transmission planning to assume that a fleet of 50 MWs of customer-owned, non-dispatchable, intermittent PV resources will be able to reliably and permanently reduce peak demand in a region by 8.8 MWs. Please refer to the previously filed testimony of Eversource witnesses Labrecque & Johnson (pages 23-25) for a more detailed discussion of this factor.

The need for demand relief in the area of the transmission network in which the DG is located

As noted above, for the purposes of valuing the transmission benefit, Mr. Beach concluded that an average value of 17.6% be assigned to each and every kilo-watt (kW) of PV nameplate capacity. Even if one accepts that 17.6% is the correct number, it should only be considered a source of value if the PV resource is located in an area of

New Hampshire that is served by a capacity constrained portion of the transmission network. To broadly compensate all PV at this level would not be appropriate.

<u>The carrying costs of any transmission project might be eliminated by the DG</u>

Mr. Beach quantifies the transmission benefit based on the 25 year, levelized forecast of ISO-NE's Regional Network Load (RNL) transmission cost. The starting point is the current RNL rate ($105/kW-year), which is escalated at 2% annual inflation. The most significant flaw in this approach is that the RNL rate is designed to recover the full, embedded carrying costs of the existing ISO-NE regional transmission network. It is not the marginal costs of a particular type of transmission project that might be designed to address a localized capacity constraint.

Q. Could you comment on the benefit category Mr. Beach refers to as "Distribution", to which he assigns a value of 2.246 cents/kWh?

A. The starting point for Mr. Beach's analysis for Eversource is a regression analysis using embedded cost data from FERC Form 1 for 2002 through 2015. Mr. Beach interprets the results of his regression analysis as the marginal distribution capacity costs for Eversource ($133.14 per KW-Year; levelized after escalating at 2% for 25 years).

On page D-7, Mr. Beach discusses the use of "peak capacity allocation factors" (PCAF) to "allocate these marginal distribution costs to the high-demand hours of the year". He provides a source for this methodology in footnote 12 (the "Public Tool" developed by Energy & Environmental Economics (E3) for the California Public Utilities Commission). However, in response to a discovery question (Unitil 1-55), Mr. Beach notes that he did not actually use the PCAF approach. Instead, he used a uniform distribution over the top 100 demand hours at each substation for which hourly loads were provided. In the case of Eversource, hourly data from 49 substations (representing 88% of customer load) was provided.

Mr. Beach provided all of his work-papers and spreadsheets in response to various discovery requests, including Eversource 1-47. Relative to the "Distribution" benefit category, he provided two sets of analyses: one using the top 100 load hours and one using the PCAF methodology.

As noted in his response to Unitil discovery question 1-55, the "PCAF allocation produces essentially the same result". Given that: 1) the original testimony referenced the E3 CPUC tool which uses PCAF; 2) the PCAF methodology is more detailed and incorporates a more robust review of substation loading; and 3) Mr. Beach asserts that the methods produce "essentially the same result", Eversource has the following observations regarding the PCAF analysis provided by Mr. Beach.

For every hour of 2015, the PCAF analysis considers the extent to which the substation load in that hour is greater than 90% of the annual peak load experienced at that substation. Those hours are used, after weighting the hourly result by an assumed PV profile for 2015 (from PV Watts), to determine a factor that is referred to as "Effective PV Load Match using Distribution Substation PCAFs (%)" (from Table D-7 in the TASC testimony). For Eversource, this factor is 22.64% *[see note below]*. This factor is used to represent the amount of customer demand growth that can be avoided by a unit of installed PV capacity. This would suggest that for every 1000 kW of PV capacity that is installed, Eversource would be able to serve the firm power requirements of approximately 226 kW of new customer peak demand. As this would avoid the capital and O&M expenses associated with this marginal growth in demand, the argument goes, the owners of the PV resources should be compensated at a rate consistent with 22.64% of the marginal distribution capacity cost.

At a high-level, Eversource strongly disagrees that, on average, every 1000 kW of new PV should be compensated for the marginal cost associated with serving 226 kW of firm peak demand (or some other similar percentage). Of all the positive attributes related to solar PV, the ability to serve firm peak demand is not one of them. Please refer to the previously filed testimony of Eversource witnesses Labrecque & Johnson (pages 23-25) for a more detailed discussion of this factor.

[Note: the 22.64% includes one erroneous hourly data point that Eversource provided and which was used in Mr. Beach's analysis. The loading at Great Bay substation on 11/30/15 hour 14 was in error and has been corrected in a revised analysis performed by Eversource, and that correction was shared with the parties to the docket. In that revision, the PCAF result was 23.10%]

Relative to the specific mechanics of the PCAF analysis, Eversource observes that the hourly substation analysis compares the load in each hour to *90% of the peak load at that substation*. The absolute peak load at a particular substation is of minimal relevance to this discussion, unless the substation is approaching a capacity overload condition. Eversource believes it would be more appropriate to examine hours in which actual substation loading is greater than *90% of the design rating of the substation transformers*. This would produce a more accurate analysis of the extent to which DG may help alleviate a potential, future substation overload. Of the 49 substations reviewed in this analysis, only 3 experienced a peak hourly load in 2015 that exceeded 90% of the transformation capacity. The average peak hourly load across all 49 substations was 62% of the rating of the transformation.

Eversource has created a revised PCAF analysis using the spreadsheet provided by Mr. Beach. After replacing the "90% of peak demand" threshold with "90% of substation transformer rating", the Effective PV Load Match using Distribution Substation PCAFs (%) dropped from 23.1% to 1.2%. Inserting this revised value into Table D-7 results in a decrease in the "Avoided Distribution Capacity" benefit from $22.46 per MWh to $1.21 per MWh.

In summary, Eversource believes Mr. Beach's evaluation of the "Distribution" benefit is significantly overstated and suffers from both the use of a flawed methodology for the calculation of the Eversource marginal cost of capacity, and by failing to consider that the majority of Eversource substations are not approaching their capacity limit.

Note: the design capacity ratings of Eversource substations were provided in various discovery responses from Eversource – EFCA-TASC question 1-003 and STAFF question 1-25 – and were therefore available for Mr. Beach's analysis.

Q. Are you aware of any other studies of the "Distribution" benefit that are notable?

A. Yes. Eversource has reviewed a report prepared by Nexant, Inc. for Central Hudson Gas & Electric (CHG&E) that incorporates in a quantitative manner the various factors described qualitatively in the previously filed testimony of Eversource witnesses Labrecque & Johnson (pages 23-25). *See* "*Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods (June 2016)*" – by Nexant, Inc. for CHG&E.

Page 1 of the Nexant report summarizes the focus of the study:

- Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investment at a local level
- Develop location specific forecasts of growth with uncertainty
- Quantify the probability of any need for infrastructure upgrades at specific locations
- Calculate local avoided T&D costs by year and location using probabilistic methods
- Identify beneficial locations for DERs

Page 24 of the report summarizes the results on the "avoided distribution substation cost estimates".

The conclusion was that, of the 53 substations in CHG&E territory, "a total of three substations have potential avoided costs – Lawrenceville, Coldeham, and Hunter. Most substations either have ample room for growth or declining loads. For a couple of substations – Grimley and Woodstock – load growth can be addressed via relatively low cost permanent load transfers to neighboring substations. Without targeting, the *likelihood that reductions will be at a location where it might help defer or delay substation upgrades is relatively low, diluting the value to $0.23/kW-year."*

It is notable that the three identified substations (Lawrenceville, Coldeham, and Hunter) have significant, location-specific avoided costs estimates ($119.19, $31.46 and $275.34 per kW-year, respectively). However, as the remaining 50 substations have an avoided cost estimate of zero, the average, system-wide, untargeted estimate is only $0.23 per kW-year (Nexant, Table 4-3).

Q. Please comment on the lifespan of a utility transmission and/or distribution investment relative to the lifespan of DG.

A. Eversource provides the following language taken from page 84 of the NARUC final publication of its manual, *Distributed Energy Resources Rate Design and Compensation (November 2016)*.

*The lifespan of certain DER systems is generally 20–30 years (and may be less for individual parts such as the inverter, and output may decrease over time), which may be significantly shorter than the distribution and transmission investments made by the utility to serve a customer. How to plan for the asset lifespan poses an interesting problem for arises regarding [**sic**] utility system planning. A regulator must question how best to make the value of those assets match. Some types of DER, like DR and EE, generally affect demand and have different expected lifespans than other types of DER, like solar PV, which affects supply.*

The NARUC manual also provides the following observation in footnote 115 (page 84): *A regulator can compare the average service lives for FERC Accounts 361 to 369 for its distribution company providers to ascertain the difference for each utility or provider. An example from Nevada Power Company and Sierra Pacific Power Company shows accounts range from 38 to 70 years. See Attachment AED-4, Docket Nos. 15-07041 & 15-07042.*

Q. Could you please also comment on the "Value of Solar" analysis submitted via the pre-filed testimony of Lon Huber on behalf of the Office of Consumer Advocate?

A. First, regarding avoided distribution system costs, Mr. Huber states "Our analysis did not include any avoided distribution system costs as these are highly location-specific and difficult to quantify". Eversource agrees with that assessment, as detailed above.

Referring to page 47 of Mr. Huber's testimony, he provides a Low Case and a High Case valuation of certain benefit categories. Eversource's primary disagreement with this valuation is the category labelled "RPS" and assigned a value of 5.0 cents/kWh in the Low Case and 3.8 cents/kWh in the High Case. As confirmed via OCA's response to Eversource discovery question 1-33, those values are based on the forecasted cost of a REC, rather than on the benefit to Eversource of having one less kWh of retail sales for which to obtain RECs in compliance with the RPS obligation. In other words, Mr. Huber's valuation suggests that Eversource would take ownership of the RECs created by net metered solar resources.

This conflicts with current net metering regulations and also with Eversource's proposal in this docket. Under Eversource proposal, the average valuation of net metered solar production (at current tariff rates) would be 10.26 cents/kWh (see discussion above). If one subtracts the 5.0 cent REC value from Mr. Huber's low case total on page 48 of his testimony, the valuation decreases from 12.8 cents/kWh to 7.8 cents/kWh. This is lower than the average rate included in the Eversource proposal, under which customers retain the RECs and can either keep them or sell them for additional benefit.

Q. Have parties in this docket suggested that the replacement net metering tariff include an option by which Eversource is required to purchase the RECs from individual customer-generators? What is Eversource's position on this topic?

A. Yes. The testimony of Lon Huber (on behalf of OCA) and James Bride (on behalf of NHSEA) include proposals under which the host distribution utility would be required to purchase RECs and either use them for RPS compliance or resell them into the REC markets.

Eversource is not supportive of any proposal under which the host utility would be required to purchase RECs. The RPS statute and the implementing regulations (Puc 2500) should not be confused with the net metering statute and its regulations (Puc 900). The two programs serve related, but different purposes and should remain separate. The legislature, via HB 1116, directed the NHPUC to open an investigation into alternative net metering tariffs. There is no mention of the RPS program, or the processes by which customer-generators obtain RECs, or the administrative rules and practices by which utilities and other load serving entities purchase RECs or otherwise comply with the RPS obligation. Eversource is generally supportive of efforts, either at the legislature or the NHPUC, to lessen the administrative effort required for residential and small commercial customer-generators to obtain and earn revenue for RECs. However, to further entangle utility business practices and rate setting with a consideration of RECs is not advisable, especially since competitive, market-based solutions and REC marketing service providers already exist.

IV. <u>RATE DESIGN</u>

Q. Following on the cost and value issues identified, there is still the issue of how rates would be set. At the start of this testimony you mentioned that you did not see a reason to change the Company's rate design proposal. Could you restate what Eversource's proposed rate design is?

A. As explained in Mr. Davis' testimony, in two of the Company's rate classes, Residential Rate R and General Service Rate G, distribution and transmission service rates are presently assessed on a volumetric kWh basis. In its proposed DG rates, the Company has converted the per kWh distribution and transmission rates of existing Rate R and Rate G to a per kW basis. In performing this calculation, the Company has retained the existing Commission-approved customer charge, and based the design of the kW-based rate on the need to recover a fair share of the remaining, approved revenue requirement from DG customers via a demand charge. Such a charge follows fundamental rate design principles and statutory tenets in this proceeding, particularly for addressing cost shifting and aligning rates with cost causation (capturing cost of service for distribution and transmission service that are demand-related), and unwinding from the shifting of costs designed to be recovered through a per kWh charge within a given rate class. The same revenue targets for rate design approved by the Commission in setting the current kWh-based distribution and transmission rates for these rate classes have been utilized in recalculating a corresponding per kW rate, using the kW demands of customers in each rate class. Since most of the non-customer charge revenue requirements of Rate GV and LG are charged on a per kW basis in the current design, no redesign of the delivery charges for those rate classes is proposed in the DG rates.

This concept is supported in the NARUC manual mentioned previously. "Energy throughput (kWh) is not necessarily a good proxy for cost causation on a distribution network. For example, a demand charge based on kW is a much better proxy and a distribution rate based on kW rather than kWh may be a more economically efficient manner to eliminate cross subsidies in distribution rates." (Page 88)

Secondly, under the Company's proposal, the distribution, transmission, Stranded Cost Recovery, System Benefits and Electricity Consumption Tax charges would all be assessed on the quantities registered in the "purchase" channel of the meter and there would be no "crediting back" of these charges based on quantities in the "sales" channel. This approach requires customers to pay for delivery services based on their purchases from the grid and prevents bypass of components of service which are, by statute, non-bypassable charges that all customers are required to pay. Since the proposed design is based on current, approved rates, it will address the near-term requirement for serving qualified, new DG facilities. The Company will collect usage data from customers on the new rates to determine if they impose additional costs which should be recognized in a subsequent rate design.

Q. While Eversource is proposing to implement a demand charge, other parties have argued that that time of use ("TOU") rates provide better price signals than demand charges. Do you agree with that argument?

A. No. The concept of TOU rates has become overly broad and vague, making such comparisons unclear, particularly with respect to what is meant by TOU rates and the distinction between rates for delivery and generation supply service versus compensation for DG production and sales of that production at the customer delivery point. For Distribution service, most demand -related distribution costs are a function of a customer's maximum demand, whenever it occurs.

While there is no time-differentiation for these costs, there is a diversity of demand that is factored into the allocation of costs to a given rate class, which is reflected in the revenue requirement for the demand-related (and, to some extent, customer-related) distribution cost of service for each class. A demand charge sends an appropriate and efficient price signal, and is an especially important and relevant design for resolving the issue of cost shifting while charging customers for what they use based on actual, metered demand on the system.

With respect to a transmission demand charge, while there is greater differentiation on a time of day basis in terms of the date and time in which the Company's transmission demand charge and therefore expense for transmission service is incurred, the allocation of costs to a specific rate class reflects this time differentiation, as well as the diversity of load at the class level discussed with respect to distribution demand. To this extent, there is a TOU element intrinsic to transmission rates. While the generation component of service (i.e., ES) reflects underlying costs that vary most on a TOU basis, the Company has not proposed any changes to such rates, as the price for such service is set on a uniform, per kWh basis. To the extent the focus on rates in this proceeding is ultimately seeking to achieve greater differentiation of rates on a TOU basis for compensation of DER, that should be made clear.

Q. Some parties have suggested that DG customers may not understand or be able to respond to demand charges. Do you agree?

A. The Company believes that such a charge is appropriate and provides a strong price signal to customers about their delivery service requirements. Customers may have some measure of discomfort or concern about a new rate or charge. We recognize the importance of customer understanding and acceptance of rates, and the need for information and communications associated with introducing a new charge. At the same time, demand charges are not a new structure per se. Additionally, this charge would be applied prospectively only, to customers who are likely to be more sophisticated in their understanding of electric service. Concerns about acceptance of or an adjustment to a new structure should not be the basis for adopting or rejecting a charge.

Under Eversource's proposal, the demand charge will apply to the customer's highest 30 minute demand during each billing cycle. With some fundamental education and information, the Company believes that a customer can readily comprehend the application of a demand charge and implications to making wise-use decisions for electric service. For example, it would seem relatively straightforward for customers to understand that running the air conditioner and electric dryer at the same time would place a greater demand on the system than running one or the other at a time, and will incur a higher charge. Eversource expects that many customers choosing to install DG under the proposed tariff will be interested in commercially-available usage monitoring technology to assist them in understanding and controlling their maximum demands. Customers who choose not to avail themselves of this technology can still reduce their demands by staggering the use of the major appliances in their homes.

Q. On behalf of TASC, Mr. Beach states at page 30 of his testimony, that demand charges for small DG customers are not cost-based or otherwise appropriate. Do you agree?

A. No. As a first matter, Mr. Beach points out that customers who install solar DG systems serve a significant portion of the load with their on-site generation. Taking that as true, then whatever demand might have been placed on the utility system during operation of the solar system will be offset by the on-site generation. Therefore, if a customer sets high use activities for times when on-site generation is available, the demand on the utility system when on-site generation is unavailable would be low and, correspondingly, so would the demand charge. Only if a customer's activities occur when the solar DG system is not producing – i.e., when the customer requires power imported from the utility grid – would there be a meaningful demand to measure. Therefore, the measure of demand would be aligned with the customer's level of transmission and distribution service requirements from the utility grid.

Additionally, Mr. Beach provides a theoretical example where a customer would pay a demand charge for importing power on a cloudy, low-demand day but is not compensated for providing "peaking capacity" on a hot, sunny day in the same billing cycle. Whether the customer provides "peaking capacity" may, arguably, relate to the value of the energy that the customer provides, but it does not relate to the costs of the utility. As noted, Eversource must have a system capable of serving all customers if all of them have DG and all DG is operating, if all of them have DG but none of the DG is operating, or if none of them have DG. That need to serve a peak capacity exists at all times, not just hot, sunny days.

Q. Compared to Eversource's proposal, are there practical obstacles to implementing TOU rates for new residential and small general service DG customers?

A. The Company does not anticipate significant incremental costs to deploy the metering required to support its proposal. These meters would be similar to those already in use for current net metering customers billed under the Company's Rate G, and the billing would be similar in many respects, as well.

On the other hand, meters to support a TOU rate design would need to be factory programmed to measure usage over the specific time periods, and, depending on the rate design, might require time of use registers on both the import and export channels. Additionally, the increased number of quantities that would need to be measured and collected would likely require changes in the AMR reading software. Since the Company does not have similar rate structures in place, additional costs would be incurred to modify the billing system. The amount of time and expense required to implement TOU rates would depend on the specific design of the rate (e.g., which rate components they would apply to; whether they would apply to the import or export channel, or both channels; the number of time periods involved, etc.).

Q. Can you please summarize your recommendations?

A. The proposal in Eversource's testimony better aligns rates with cost causation and helps address the issue of cost-shifting between net metered and non-net metered customers while still allowing for the growth of investment in distributed generation within New Hampshire. For these reasons, Eversource's proposal should be accepted by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.