EXHIBIT #14 DE 16-576

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

DIRECT TESTIMONY OF RICHARD C. LABRECQUE AND RUSSEL D. JOHNSON

October 24, 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. Labrecque, what are your duties and responsibilities at Eversource?

A. My duties include the processing of applications to interconnect with the Eversource (NH) distribution system and the administration of interconnection agreements with non-utility generators.

Q. Mr. Labrecque, have you previously testified before the Commission?

A. Yes. I have testified on several occasions before the Commission.

Q. Mr. Labrecque, would you provide a brief summary of your educational background and work experience?

A. I have approximately 25 years of experience in the utility industry. From 1992 to 1998, I was employed as an engineer and performed a variety of safety analyses in support of the

Northeast Utilities (now Eversource Energy) fleet of nuclear generating stations. In 1998, I joined the Wholesale Power Contracts department. My responsibilities included providing the analytical support required to fulfill the power supply obligations of PSNH, CL&P and WMECO. For PSNH, I assisted in the development of the Energy Service rates and the strategy used to procure energy and capacity needed to supplement PSNH's resources.

In 2009, I became manager of Distributed Generation (DG) for Eversource-NH. DG is responsible for Eversource's relations with all customers seeking to interconnect generation resources to the Eversource electric distribution.

I hold a Bachelor of Science degree in Nuclear Engineering from Rensselaer Polytechnic Institute, a Master of Nuclear Engineering degree from North Carolina State University, and a Master of Science degree in Management from Rensselaer at Hartford.

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. Johnson, what are your duties and responsibilities at Eversource?

A. My primary responsibility is the long term planning of the Eversource transmission and distribution system in New Hampshire.

Q. Mr. Johnson, have you previously testified before the Commission?

A. Yes. I have testified previously in the Reliability Enhancement Program docket (DE 09-035) and in the Least Cost Planning docket (DE 13-177).

Q. Mr. Johnson, would you provide a brief summary of your educational background and work experience?

A. I graduated from Clarkson University in Potsdam, NY in 1985 with a Bachelor of Science in Electrical and Computer Engineering and in 1987 with a Master of Science in Electrical Engineering with a concentration in Power Engineering.

Upon graduation from Clarkson University, I was hired by Public Service of New Hampshire and have held various positions in Distribution Engineering, Large Commercial and Industrial Sales, System Projects, and System Planning with increasing responsibility through my current position as Manager – System Planning. I have been a licensed Professional Engineer in the State of New Hampshire since 1990.

Q. What do you understand the purpose of this proceeding to be?

A. This proceeding was initiated in order to comply with the requirements of HB 1116, "AN ACT Relative to Net Metering," (31 N.H. Laws 2016) enacted by the legislature during its 2016 session. RSA 362-A:9, XVI added by that law required initiation of this proceeding. In the "Purpose Statement" of the new net metering law (§31:1), the Legislature notes that its first two objectives continue to be the creation of competitive electric markets and customer choice to reduce costs for all customers. In the substantive portions of the new law, the Legislature specifically instructed the Commission to avoid unjust and unreasonable cost shifting caused by net energy metering customers.

Q. What is the purpose of your testimony?

A. The primary focus of this testimony is to describe the cost shifting (from net metered customers to non-net metered customers) that is inherent in the existing net energy metering (NEM) tariff design. A new tariff design intended to address this issue is included in the testimony of Mr. Edward Davis. To explain the issues with the current design, we will discuss the costs and benefits associated with small scale, distributed energy resources (DER) from the perspective of Eversource and its New Hampshire customers. Our testimony will also include an overview of the administrative processes required to implement the interconnection and net energy metering of customer-generator facilities. The testimony will start with a general summary of the concept of NEM and question whether it is just and reasonable to all customers.

Q. What is "net energy metering" or NEM?

A. The term "net energy metering" refers to a billing arrangement where the standard billing meter is replaced with a "net meter" that is able to "spin backwards" to reflect periods of time during which a customer-sited source of energy is producing more power than is being consumed internal to the property (i.e. surplus energy is being produced). The customer is billed only for the "net" energy consumed during the billing cycle. Over the last few years, Eversource has installed a new style of net meter that no longer relies on "spinning backwards" (either mechanically or digitally) to enable this billing treatment. The new net meters have two measurement channels. The "purchase channel" records all net energy (kWh) delivered from the Eversource distribution system to the customer. The "sale channel" records all net energy delivered from the customer to Eversource. In this case, the term "net energy" is used to highlight the fact that the meter does not separately measure total internal consumption (e.g. power for lights and appliances) and total customer-sited power production (e.g. solar power). It only measures the net power. For example, consider a home where solar panels are installed. When the house lights and appliances are consuming 5 kW of power and the rooftop solar panels are producing 3 kW of power, and that condition persists for an entire hour, the purchase channel of the meter will record 2 kWh of net consumption. Similarly, the sale channel only records the net power exported from the property to the Eversource system. Thus, given this style of metering, Eversource could bill a customer on the "gross" consumption recorded in the purchase channel. However, under the existing NEM tariff, the two channels (purchase and sale) are netted together to determine the net monthly kWh to bill the customer.

Q. Please describe the origins of net energy metering?

A. Net metering became a popular billing method in the 1970's after the rise in energy prices associated with the oil embargo and subsequent interest in more use of domestic energy sources; and, in the case of net metering, small scale applications on the "customer side of the meter". Most often, this billing arrangement came about through state legislation around the country with limitations on the aggregate amount of customer generation that could take advantage of this billing method.

In New Hampshire, NEM was first introduced via HB 485 in 1998. That initial legislation permitted systems up to 25 kW in size and limited the total program size to 0.05% of the annual peak energy demand of each utility. Over the years, subsequent legislative action resulted in various changes to the program. Some of these changes are summarized below:

2007 Session – HB 447 - effective date 8/17/2007

- Expanded maximum system size from 25 kW to 100 kW.
- Expanded total program limit from 0.05% of the NH peak load to approximately 1% of the NH peak load.
- Allowed the banking of kWh for use in subsequent billing months

2010 Session – HB 1353 - effective date 8/13/2010

- Expanded maximum system size from 100 kW to 1,000 kW. Systems over 100 kW were required to be "new" (i.e. commenced initial operation after July 1, 2010).
- Allowed for 3rd party ownership of systems (i.e. solar project not owned by the utility customer)
- Eliminated language that required the energy produced to be "intended primarily" to serve the customer's own electricity requirements
- Expanded total program limit from 1% of annual peak (approx. 25 MW) to 50 MW statewide
- Created an annual payment option for accumulated surplus kWh
- Clarified that utilities may file for cost recovery of lost distribution revenues due to net metering

2013 Session – SB 98 – effective date 7/24/2013

- Allowed for "Group Net Metering", with all payments for surplus going to the Group Host
- Eliminated the requirement that larger systems (those over 100 kW) be "new", thus, allowing older hydro-electric facilities to qualify for net metering rate treatment

2014 Session – HB 1600 – effective date 8/15/2014

- Clarifies the legality of 3rd party ownership and the use of PPAs (electricity purchase contracts between the 3rd party and the customer)

2016 Session – HB 1116 – effective date 5/2/2016

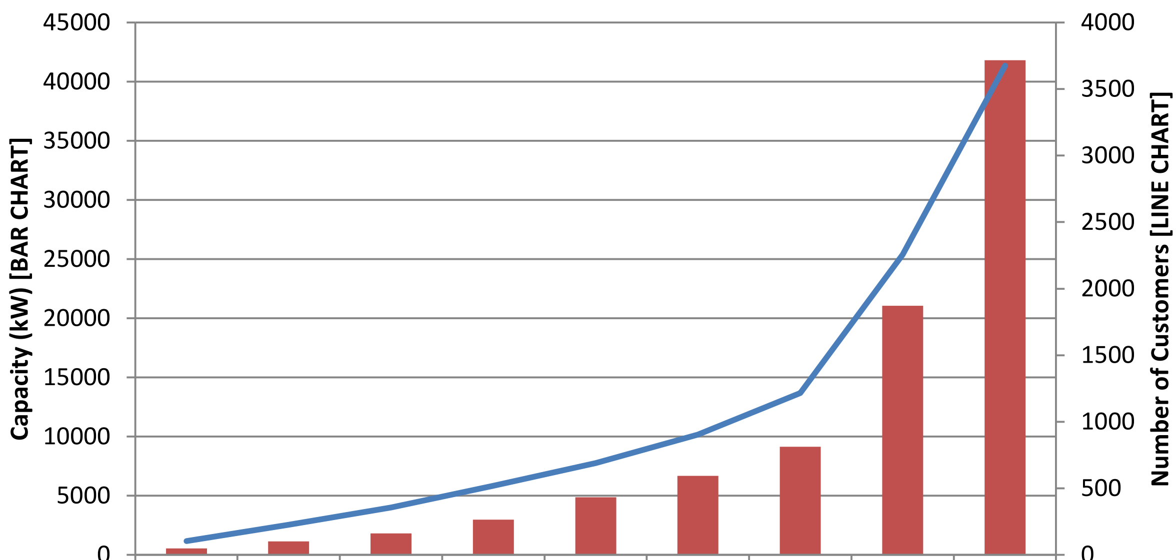
- Expands total program limit from 50 MW statewide to approximately 100 MW (~4.5% of the NH peak)
- Initiated NHPUC investigation of replacement tariff (DE 16-576)
- Grandfathered existing net metered customers until 2040.

Q. What is Eversource's general position on net metering today?

A. Eversource is strongly supportive of renewable energy and believes that customers should be provided with reasonable opportunities to invest in DG. In the early years of net metering, only a handful of customers took advantage of the program for a variety of reasons. Solar costs, in particular, were high and self-generation did not appeal to most home or business owners. For many years, the number and size of net metered facilities were so low that there was no material impact to other customers.

However, as the cost of solar has declined and incentive programs have been made available, more and more customers have taken an interest in net metering and self-generation as a way to reduce or control their energy expenses. The growth of net metering applications in the Eversource (NH) territory is depicted in Figure 1. Given this rapid growth, Eversource believes it is time to take a comprehensive look at the net metering system and to make revisions to ensure that net metering practices are consistent with the legislature's objectives of "reducing costs for all customers" and avoiding "unjust and unreasonable cost shifting."

Figure 1 - Growth of Net Metering - Eversource NH



	Pre-2009	2009	2010	2011	2012	2013	2014	2015	2016 (thru Sep.)
Capacity (kW)	537	1141	1826	2979	4878	6681	9135	21058	41813
# of Customer	104	227	357	519	691	904	1215	2255	3676

Eversource testimony on a replacement tariff design is provided by Mr. Davis. This testimony will describe how the existing net metering tariff leads to subsidization of net metering customers by all other customers and how, given the expansion of net metering, it has resulted in an unreasonable shift of costs.

II. NET METERING IS AN UNJUST COST-SHIFT TO NON NET METERED CUSTOMERS

Q. How does NEM result in a cost shift from participating customers to all other non-participating customers?

A. There are two ways in which a NEM customer (e.g. a residential solar customer) will shift costs to other customers in the form of higher utility rates over time. The first way is by paying the utility less money for the delivery services provided than the actual, embedded cost of those services. The second way is by being compensated more for excess power (i.e. exported kWh in the sale channel) than it is truly worth in the wholesale energy marketplace.

Q. How do NEM customers pay less for utility delivery services than the cost of those services?

A. First, it is important to note that many elements of utility rate regulation are based on allocating utility expenses over average or typical customer classes and profiles. It is not possible to determine the actual costs to deliver power to each unique customer. It costs more to serve some locations than it does others, yet the delivery rates are identical. Customers that have behind-the-meter generation, such as net energy metering customers, have net consumption characteristics that are materially different from a "normal" customer.

Most costs of delivering electric energy to retail consumers are related to the capacity demand of a customer – i.e., the instantaneous kW demand a customer places on the system is more important than the overall kWh delivered. However, traditional metering and rate-making principles have resulted in costs being recovered from customers based on usage (i.e. monthly kWh) rather than some other criterion such as peak demand (i.e. the monthly or annual highest kW), which in most cases may be a more appropriate determinant of the cost to serve. However, for the purposes of illustrating the concept of cost shifting, we will assume the existing rate structure is appropriate and proper, and that the cost to deliver power to a particular Eversource full requirements (i.e. non net metered) customer is appropriately reflected in the Eversource tariff rate for that customer.

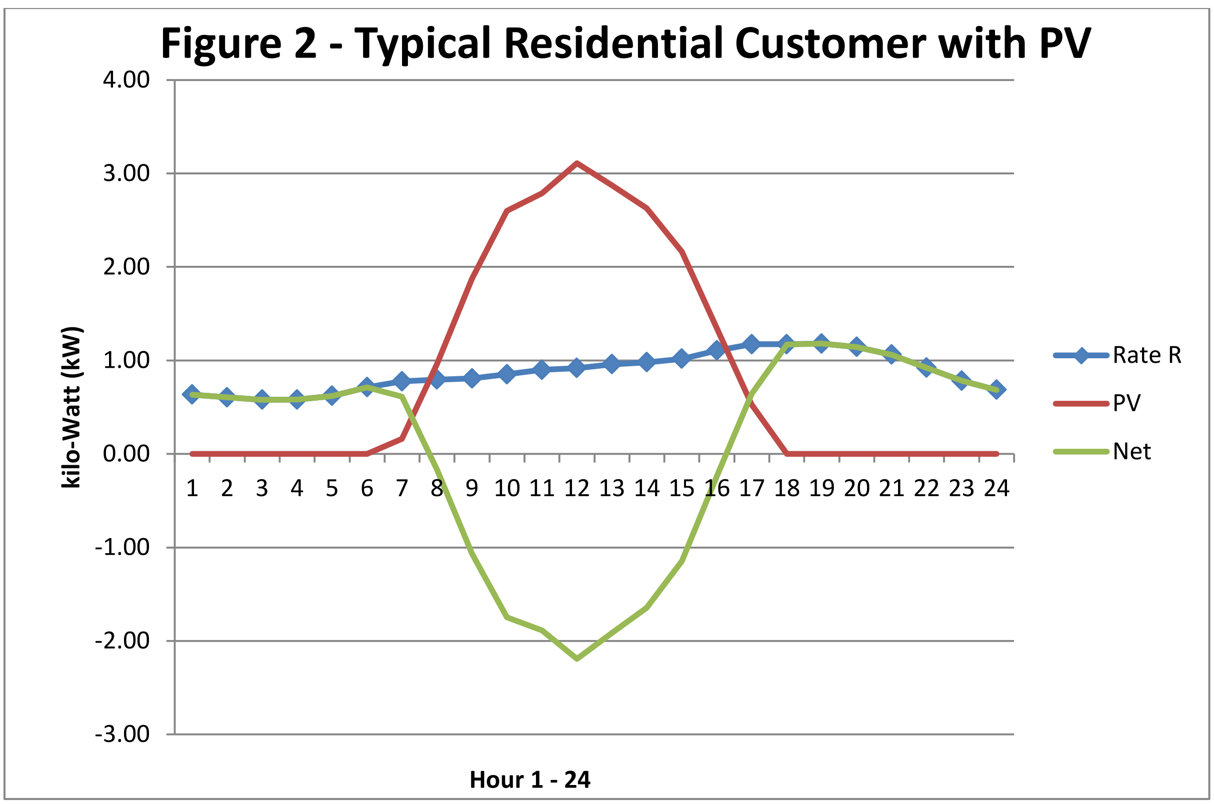
Assume a typical residential customer uses 700 kWh of energy in a given month. Based on rates in effect on July 1, 2016, and assuming the customer is taking Default Energy Service, that customer will be billed the following utility charges:

Residential Customer Bill (700 kWh)

	Rate (¢/kWh)	Bill Amount ($)
Customer Charge	N/A	$12.89
Distribution Charge	4.207	$29.45
Transmission Charge	2.390	$16.73
Stranded Cost Recovery	0.094	$0.66
System Benefits	0.330	$2.31
Energy Service Charge	10.950	$76.65
	17.971	$138.69

Now assume that this customer installs a solar PV facility and enrolls in the net metering program. Further assume that the solar facility produces exactly the amount of energy required to satisfy the customer's monthly usage (in this case, 700 kWh). Of course, the usage profile and the solar production profile will be very different over the course of the month, but under the existing net metering tariff that mismatch between production and use is irrelevant.

Figure 2 below depicts a typical daily internal consumption profile and solar PV production profile for a residential customer in the month of September. These profiles are labeled "Rate R" and "PV", respectively. As shown, during the morning and evening hours of the day, the customer is a net purchaser of energy (usage exceeds solar production). This net usage is measured in the "purchase channel" of the Eversource meter. During most of the daylight hours, this customer is a net seller of energy (solar production exceeds usage). This net surplus is measured in the "sales channel" of the Eversource meter.



Under the existing net metering tariff, all kWh quantity-based charges drop to zero, leaving only the "Customer Charge" and the customer's bill would be reduced to $12.89 (see comparison table below).

		Before Solar	After Solar
	Solar Production (kWh)	0	700
	Metered Purchases (kWh)	700	350
	Metered Sales (kWh)	0	350
	Net Billed (kWh)	**700**	**0**
	Billing Rates		
Customer Charge	$12.89 per month	$12.89	$12.89
Distribution	4.207 cents/kWh	$29.45	**$0.00**
Transmission	2.390 cents/kWh	$16.73	**$0.00**
Stranded Costs	0.094 cents/kWh	$0.66	**$0.00**
System Benefits	0.330 cents/kWh	$2.31	**$0.00**
Energy Service	10.950 cents/kWh	$76.65	**$0.00**
	Total Bill	**$138.69**	**$12.89**

Q. In the example above, the customer paid to Eversource only the $12.89 "Customer Charge". What does that charge represent and is it sufficient to cover Eversource's total embedded cost to provide service to the customer?

A. The Customer Charge ($12.89) recovers a portion of the customer-related costs of making service available to a customer, such as installing and maintaining meters, customer transformers, service wires, as well as meter reading and customer service. This charge only recovers a portion of the total customer-related costs to deliver power to a customer's property. The remaining customer-related costs, as well as other delivery costs, are recovered via the "Distribution Charge" discussed next.

Q. After installing solar, the customer avoided paying $29.45 for the kWh-based portion of the "Distribution Charge". Is that appropriate?

A. No. The distribution charge is designed to collect Eversource's costs to design, construct, maintain, operate and restore the vast infrastructure required to deliver electricity from the distribution grid to each end-use customer. The infrastructure includes poles, wires, substations, voltage regulation equipment, capacity banks, switches, reclosers, communication and other operating systems. It also includes human resources plus vehicles, buildings, etc. It includes all the costs to provide safe and reliable electrical power 24 hours per day in the exact quantity instantaneously demanded by all of our customers. Since the Customer Charge is set at less than the Company's customer-related costs, the kWh-based distribution charge recovers a portion of the customer-related costs, as well. In this example, the solar customer has contributed zero to these expenses, but still needs and has made use of all of those facilities. Eversource's collection of revenues has decreased, but expenses to provide the service have not decreased. The solar customer is reliant on the delivery infrastructure, since it provides the system synchronization necessary for the solar generation to work (i.e., without the connection to the grid, the solar generation would not be usable by the owner absent an additional investment by the customer in other technologies), provides instantaneous backup when clouds cause the generation to drop, and enables excess solar power to be distributed to the grid, thus increasing the value of the solar investment. Without the grid, the investment required to produce the same value would be substantially higher, as the solar installation would have to purchase storage capability, backup generation capability, frequency control, voltage regulation capability, etc.

Q. How does the fact that this solar customer did not pay the "Distribution Charge" result in a cost shift to non-solar customers?

A. Utility rates are set in a manner designed to allow a utility to collect its revenue requirement, which includes the costs to design, build, own, operate and maintain the electric distribution system. The overall revenue requirement is apportioned amongst customers of various rate classes as part of the rate design process regulated and approved by the Commission. Each rate class is designed in a manner such that all members of a rate class have similar characteristics. If thousands of net metered customers pay only the Customer Charge, then Eversource would not collect sufficient funds to meet its revenue requirement. Under the current net metering design, to address this revenue shortfall, Eversource would need to petition the Commission to raise rates <u>for all customers</u> to a higher level to adjust for the fact that existing (and future) net metered customers will not be making a just and reasonable contribution towards the costs of the electric distribution systems that they use. Because net metered customers avoid paying some or all of the kWh-based charges, they would have little or no reason to be concerned that the kWh-based rates have increased. Non-net metered customers, however, would be responsible for paying higher kWh-based rates to cover the costs of the system used by everyone. Thus, non-net metered customers will see higher and higher rates to maintain the electric system for the benefit of themselves, as well as the solar and other net metered customers. Absent some significant change to the way that rates are set (such as implementing the proposal submitted by Eversource in this proceeding) the shift of costs will continue to grow. Such a result is unfair and inconsistent with HB 1116's purpose of ensuring that the costs and benefits of net metering are fairly and transparently allocated among all customers. Any ratemaking strategy that includes subsidies from non-net metered customers also conflicts with the Legislature's concern for an avoidance of unjust and unreasonable cost shifting that effects the rates of all customers.

Q. Is the situation similar for all the other kWh-based charges that the hypothetical customer did not pay?

A. Yes. Transmission charges are designed to recover the costs of designing, building, operating and maintaining the high-voltage transmission network in NH and around New England. A solar customer uses the transmission network, yet does not contribute to those expenses. Similarly, System Benefit Charges, Electricity Consumption Tax, and Stranded Cost charges are all public-policy related amounts that net metered customers benefit from, but do not fairly contribute to.

Q. Is this NEM rate design sustainable?

A. No. To illustrate why, consider this NEM rate design under an extreme, hypothetical case. Assume 50% of all Eversource customers install solar panels and are net metered under the current tariff design and net their meters to zero. Since 50% of all customers would be contributing only the Customer Charge ($12.89) towards the costs of owning and operating the delivery infrastructure, the kWh-based rates charged to the remaining non-net metered customers would have to increase significantly in order for the utility to continue to collect revenues sufficient to provide the same level of service. In other words, the delivery portion of their monthly electrical bill would increase.

Q. In this example, in addition to not paying the kWh-based distribution and transmission charges, the solar customer also exported power to the grid and was effectively compensated at the retail default energy service rate (currently 10.95 cents/kWh) for the electricity. Is that appropriate?

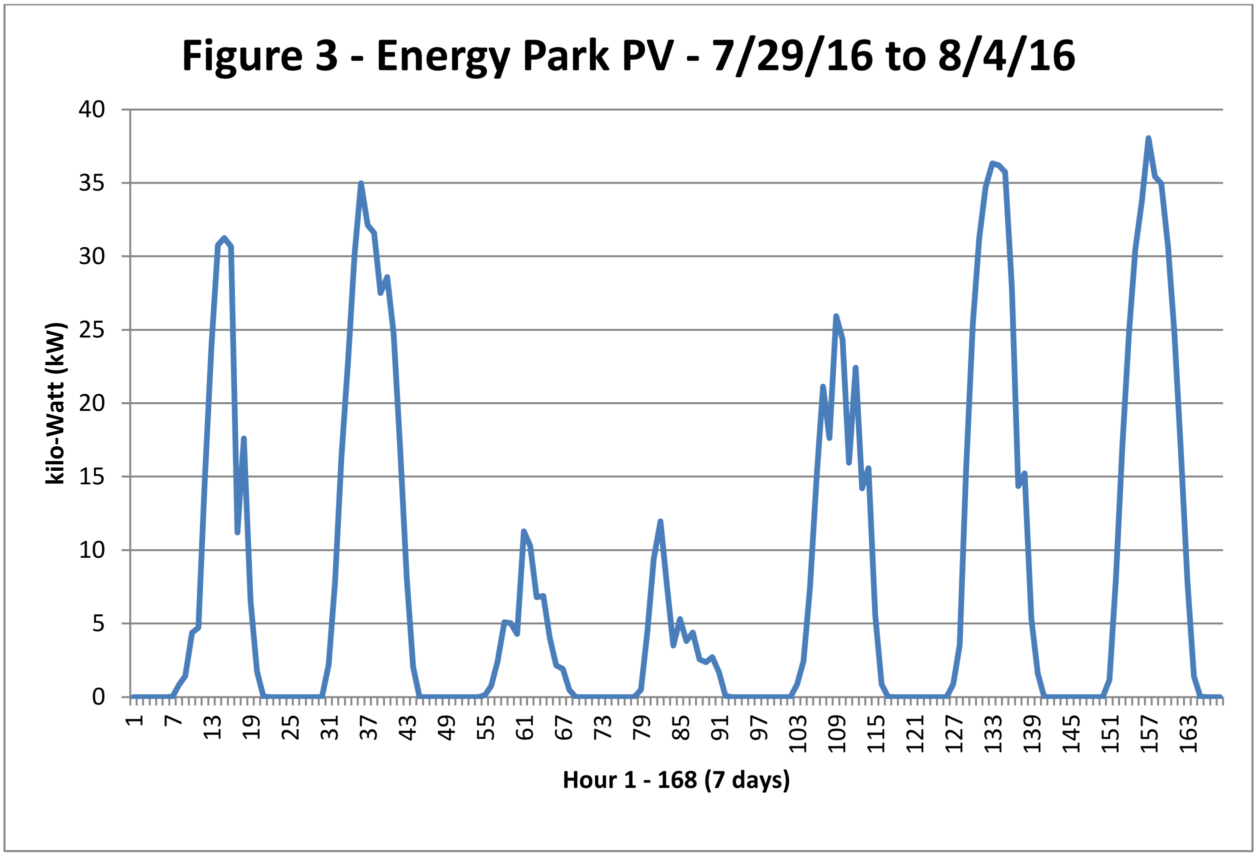
A. No. This over-market energy payment is the other major contributor to the cost shift from NEM to non-NEM customer. The retail default energy service rate is a full-requirement, load following product and is priced as such. It provides for the firm supply of power, in exactly the quantity demanded by each customer every minute of every day. It includes the cost to procure a firm supply of energy, plus capacity, ancillary services, RPS compliance, risk management, overheads, etc.

Q. How is the power supplied by a customer-sited generator (i.e. a rooftop solar PV facility) different than the power supplied by the retail energy service provider?

A. Net metered customer-sited generators are not dispatchable, by either the customer, or the utility, or the ISO-NE dispatcher. They are known as “intermittent power resources” whose output is almost entirely and without exception dependent on a variable source of fuel, e.g. solar, wind, or hydro (water). The output of these resources is very difficult to predict with any level of accuracy and, therefore, cannot be relied on by the energy supplier or the regional grid operator to serve the firm energy needs of actual customers.

Q. Do you have an example of the intermittent nature of these resources?

A. Figure 3 is a plot of the hourly production from the 50 kW (maximum AC inverter rating) solar PV project on the roof of the Eversource "Energy Park" building in Manchester, NH. The plot illustrates, during a seven day period, both the significant volatility from hour to hour (e.g. due to clouds passing over the area), as well as the day to day variation in total energy produced. It is obvious from this figure that solar PV (without storage batteries and load control devices) cannot be relied upon to serve the firm power needs of actual customers.



Q. You have stated that intermittent power resources cannot provide a firm, retail energy service product to customers. What products can they provide?

A. These resources are capable of providing wholesale energy and capacity, both of which are compensated according to the FERC-jurisdictional wholesale markets administered by ISO-NE. While most net metered projects are very small scale (for example, an 8 kW rooftop solar project), they provide wholesale products (energy & capacity) that are identical to those provided by large, central station generation resources.

Q. How are wholesale generation resources compensated in the competitive, restructured energy marketplace?

A. Generators that are registered in the ISO-NE wholesale energy market are compensated at the hourly spot market energy price for the appropriate location on the grid (i.e. the LMP, or Locational Marginal Price). This is the appropriate energy compensation for small-scale, renewable generation as well, as the Commission recently ruled in Docket No. DE 14-238. As for capacity, FERC and ISO-NE have established a complex market structure and associated market rules to procure the necessary physical capacity to serve the region. These rules assign a certain amount of qualified capacity to intermittent power resources based on a statistical evaluation of their ability to provide power during certain hours. This qualified capacity can be offered into periodic capacity supply auctions and receive compensation based on the clearing price of that auction. As with energy, these market-based rules and prices establish the appropriate method to compensate small-scale, net metered projects.

Q. Are intermittent resources such as solar PV able to provide reliable capacity to meet New England's peak energy demand?

A. ISO-NE plans for a reliable system taking into account the characteristics of the resources available to serve load and the uncertainties associated with load. With any source of power (nuclear, coal, hydro, gas-fired, wind, solar, etc.), there is the possibility that during the hour of peak demand, the generator will not be able to provide the rated capability of the machine. ISO-NE has established rules to ensure that each resource that seeks to be compensated for capacity is appropriately reflected in the market and appropriately compensated or penalized to the extent they provide or fail to provide power during periods when the system is deficient operating reserves and emergency procedures are activated.

The ISO-NE Distributed Generation Forecast Working Group (ISO-NE DGFWG) concluded that, for planning purposes, solar PV installations will reduce future summer peak loads by approximately 40% of the nameplate capacity rating of the PV facility. (For example, a 1,000 kW PV facility is expected to result in a 400 kW peak load reduction). The ISO-NE analysis is referenced below (see slide 56). The analysis also concludes that the ability of solar PV to reduce future summer peak loads is gradually reduced at higher PV penetration levels. The reduction (from 40%) begins once penetration in ISO-NE exceeds 1,400 MW. Once the total solar PV in New England exceeds 8,000 MW, each incremental PV project will only reduce peak load by 21% of the nameplate rating. This is because the actual peak load seen by system operators shifts to later in the day when solar PV generation declines. [Note: as of the end of 2015, ISO-NE had 1,325 MW of solar PV].

"ISO-NE Distributed Forecast Generation Working Group – Draft 2016 PV Forecast" by John Black, revised March 7, 2016 (original February 24, 2016)

Q. Is the continuation of Default Energy Service rate retail compensation under the current net metering system for intermittent, wholesale power resources consistent with deregulation and competitive power markets?

A. No. As previously indicated, the present net metering system unreasonably shifts costs to and increases costs for the majority of customers. In addition, the payment to net generation for excess energy at prices in excess of a utility's avoided cost violates PURPA. As PURPA provides the basis for these small generators' exemptions from Federal Power Act regulation, the PURPA requirements must be honored.

Q. Have you estimated the magnitude of this cost shift that is actually being experienced by Eversource and their customers?

A. Yes. Exhibit RCL/RDJ-1 is a summary of an analysis that was performed to estimate the cost shift. The analysis is an estimate only, and incorporates a number of simplifying methods and assumption that are explained in the exhibit. If Eversource elects to seek recovery of prior revenue losses related to net metering, as is permitted under RSA 362-

A:9 VII, a more detailed analysis will be performed. However, the more detailed analysis is expected to produce numbers that are reasonably close to this illustrative estimate.

Q. What is the estimated cost shift related to net metering?

A. Based on the installed capacity of Eversource net metered projects on June 30, 2016 (33.88 MW), the annual cost shift is over $5.2 million (see Exhibit RCL/RDJ-1). This estimate includes $947 thousand dollars from lost revenues that support the delivery system and $4.3 million dollars from paying over-market retail energy prices for wholesale energy and capacity.

Q. How will the estimated cost shift change as the quantity of net metered projects increases and reaches the current state-wide statutory limit of 100 MW?

A. Eversource's share of the state-wide 100 MW program is 75.375 MW. That is more than twice the amount of installed capacity included in the $5.2 million dollar estimate. Assuming the additional resource and customer mix is similar to the existing net metered capacity, the 75.373 MW of projects will create an annual cost shift of approximately $11.7 million.

Q. Does Eversource consider this the type of "unjust and unreasonable" cost shift that RSA 362-A:9 XVI that seeks to avoid?

A. Yes.

Q. In your discussion regarding the cost shift, you used the phrase "over-market payments" for energy and capacity. Please further explain the concept of "over-market payments" relative to net metering.

A. The term "over-market" refers to the fact that the retail compensation rate for the energy produced by net metered resources (i.e. the Default Energy Service rate or the full retail rate) is higher than the true market value of that energy (i.e. the avoided market costs).

To illustrate this fact, I have analyzed the 2015 hourly production from 16 solar PV data sets that were provided during the initial discovery phase of this proceeding (see NEW HAMPSHIRE SUSTAINABLE ENERGY ASSOCIATION'S RESPONSE TO PUBLIC UTILITY (sic) COMMISSION STAFF'S AUGUST 19, 2016, DATA REQUEST). The data sets represent 16 solar net metered facilities located at residential and commercial properties around New Hampshire. Of the 21 data sets originally provided by NHSEA, 5 were eliminated because they did not contain a complete set of hourly data from 2015. The data was reviewed relative to the hourly wholesale price of energy in capacity during 2015. A summary of this analysis is provided below:

- The PV facilities ranged in size from 4.8 kW to 69 kW (based on the maximum AC rating), with an average of 13 kW.
- The capacity factors ranged from 10.7% to 16.8%, with an average of 13.4%.
- At the hour on the ISO-NE peak demand for 2015 (July 20th at 5pm), these 16 facilities were producing (on average) only 29% of their maximum hourly production. The range was from 6% to 64%.
- For 2015, the simple average of the hourly ISO-NE real-time locational marginal price for energy (RT-LMP) was $40.20 per MWH. These prices were applicable to the New Hampshire load zone (location #4002).
- The hourly NH RT-LMP energy prices were load-weighted by the hourly demand value for the New Hampshire load zone. The load-weighted average energy price for 2015 was $43.77 per MWH.
- For each of the 16 PV projects, the hourly production data was weighted by the applicable hourly NH RT-LMP. The "production-weighted" average energy value for these 16 projects ranged from $31.80 to $39.70 per MWH, with an overall average of $35.70 per MWH for all projects.
- The production weighting was repeated after granting each project an illustrative 7.5% beneficial impact on distribution losses across the Eversource distribution system. These "loss-adjusted, production-weighted" energy prices ranged from $34.20 to $42.60, with an overall average of $38.40 per MWH.
- The wholesale capacity value of each project was determined by calculating the summer and winter qualified capacity (in kW) based on ISO-NE capacity market rules

for intermittent power resources. These qualified capacity values were multiplied by the ISO-NE Forward Capacity Market (FCM) auction clearing price for the June 2015 – May 2016 commitment period ($3.43 per kW-month). The total dollar value was then divided by the total annual production (kWh) from each project to develop an equivalent $ per MWH valuation. These values ranged from $3.89 to $9.96 per MWH, with an overall average of $6.24 per MWH.

- The sum of the energy and capacity valuations for each project ranged from $38.44 to $50.89 per MWH, with an overall average of $44.61 per MWH. These values include the beneficial loss adjustment.

Q. Please comment on the fact that the production-weighted energy value for these 16 PV projects ($38.40 per MWH) was lower than the NH load-weighted average ($43.77).

A. This result is reflective of the fact that New Hampshire and New England, while still a summer peaking region, often experiences the highest prices of the year during the winter months. Solar PV production is significantly reduced during the winter months. To illustrate this fact, the highest priced hours from 2015 were reviewed. Recall that the simple average for the entire year (8760 hours) was $40.20. The simple average of the 876 highest priced hours (10%) was $135.80. Of these 876 hours, 769 (88%) occurred in the winter months of January, February, March and December. During these hours, the total production of the 16 solar projects was 13,072 kWH, which is only 5.6% of the total annual production.

Q. Please comment on the range of values for the solar production that occurred on the hour of the ISO-NE peak demand.

A. On July 20th at 5pm, these facilities averaged only 29% of their peak production capability, with a range of 6% to 64%. Thus, some projects were producing almost zero power, while others were performing well above the average. This illustrates how difficult it is to consider customer-owned, solar PV as a source of firm capacity having the ability to serve firm customer demand.

Q. Please provide the overall summary of this "over-market" analysis.

A. For this specific analysis, the average wholesale market value (energy plus capacity) of the fleet of 16 PV resources was $44.61 per MWH (with a low of $38.44 and a high of $50.89). The average of $44.61 per MWH is equivalent to 4.461 cents/kWH. During 2015, the Eversource average Default Energy service rate was approximately 10.0 cents/kWH. Therefore, the "over-market" payment to net metered PV facilities was the difference, or roughly 5.54 cents/kWh. If these same PV facilities were full participants in the competitive, FERC jurisdictional, wholesale energy and capacity markets, they would have earned revenues of only 4.46 cents/kWH. Requiring utilities to, instead, pay these projects 10.0 cents/kWH, represents a state jurisdictional subsidy that shifts costs to non-net metered customers and is inconsistent with PURPA's requirement that rates paid to QFs be not "more than the avoided costs for purchases" 18 CFR 292.304 (a) (2). *Note: the "over-market" payments discussed in this section (i.e. the 5.54 cents/kWh) only relate to the energy service portion of the net metering subsidy. The avoidance of delivery charges (distribution and transmission) represents an additional subsidy which, for residential customer-generators, is currently 6.5 cents/kWh.*

III. <u>THE IMPACT OF DISTRIBUTED GENERATION ON THE ELECTRIC DELIVERY SYSTEM</u>

Q. How will the increased penetration of solar and other source of distributed generation impact the cost of utility delivery service?

A. The impact of distributed generation (DG) on the delivery grid is highly dependent on the type and quantity of DG and the exact location to which it interconnects with the distribution system. In general, at today's levels of penetration, the impact of DG is very local and is addressed as each individual DG project is evaluated by Eversource engineers prior to interconnection. If the interconnection of a DG project is determined to require modifications to the Eversource distribution system, the costs of those modifications are allocated to the DG owner (i.e. the Customer-Generator) as required by NH RSA 362-A:9 XIII which states that the "Customer-Generators shall be responsible for all costs associated with interconnection with the distribution system". The intent of the law is, presumably, to ensure that the costs to interconnect a DG resource are not passed along to other customers in the form of higher distribution rates. The law also ensures that the opportunity for a distribution utility to earn the allowable rate of return between rate cases is not diminished by the costs of interconnecting DG resources.

At lower circuit penetration, small-scale resources (e.g. rooftop solar) typically require no modifications to the Eversource system. Occasionally, the existing Eversource transformer that feeds the individual customer must be replaced with a higher rated transformer to accommodate the DG resource. Also, the service wires to a property may need to be upgraded to a higher rating. The Eversource expenses (i.e. labor and materials) associated with these upgrades, which are funded by the customer and are only to serve that customer, have no effect on the delivery system costs that must be recovered in base rates to all customers.

Large DG projects, e.g. a 1000 kW solar PV acting as a Group Host, will require more substantial modifications, such as the installation of a SCADA-controlled recloser at the point of interconnection. Most will require Eversource to tap a circuit and install a series of poles along with the associated conductors to bring delivery service to the new DG site. As with smaller projects, the customer (or developer) is required to fund these expenses, such that the rates of other customers are not affected.

Q. How might this dynamic change as the penetration of DG resources increases?

A. Eversource is fully committed to a modern, reliable grid. Between July of 2015 and June of 2017, Eversource will have invested in excess of $80 million in distribution automation and other reliability enhancement programs. One element of grid modernization is the ability to interconnect higher penetrations of DG (see docket IR 15-296 Investigation into Grid Modernization). In order to accomplish this goal, the Eversource delivery system will need to be able to function reliably even when the magnitude and direction of power flow is volatile and unpredictable. This includes having substation transformers, load-tap changers, and breakers, as well as circuit voltage regulators and capacitor banks that can operate dynamically and automatically as the magnitude and direction of power flow fluctuates during the day. Communication and control technologies will need significant upgrades to provide for proper coordination and operation of the system. Outage management systems, devices providing fault detection information, and automated restoration algorithms will need to address the existence of DG resources on the system. Power restoration practices will need to adjust to recognize the existence of power generation situated throughout the system. While the details are beyond the scope of this docket, it is important to emphasize that the future costs to integrate a higher penetration of DG will be considerable.

Q. Is it possible that the continued growth of distributed generation may help the utility avoid costs for transmission and distribution infrastructure?

A. Recognizing certain limitations discussed below, it is possible that an aggregation of DG resources could eliminate or delay the need for circuit upgrades to accommodate growth in customer peak demand. For example, consider a hypothetical circuit that has experienced customer load growth, such that the delivery infrastructure (e.g. substation transformer, circuit conductors, or other limiting equipment rating) is approaching a capacity limitation. Within an integrated resource planning environment, DG resources can be evaluated as a potential solution to defer or cancel a planned distribution utility project intended to solve the pending capacity constraint. However, the ability of DG to provide a viable solution is influenced by the following factors:

- Unless part of a focused utility or regulator-sponsored solicitation, <u>DG resources are constructed in random locations</u> based on the particular customers that make these investments. The vast majority of these DG resources will be located on portions of the Eversource system that have no pending capital projects that are accommodating demand growth. Thus, they do nothing to defer or avoid any utility capital costs.
- Even if a new DG resource is located on a circuit that is projected to reach a capacity limitation in the next few years, the hour-to-hour production from the resource may be totally beyond the control of the operating utility and will likely not match the electric usage patterns of the customers on that circuit; i.e., the peak loads on our

system generally do not coincide with the timing of DG output. For example, during the summer, peak loads generally occur in the 5:00 to 8:00 pm time period. Circuits with higher concentrations of commercial load peak earlier and circuits serving primarily residential customers peak later. Solar generation begins to wane prior to this peak, creating a mismatch between their generation and system needs. Hence, there is an uncertain contribution of such DG generation to peak reduction.

- Only a subset of utility capital projects is based entirely, or even partly, on customer load growth. Utility capital projects are primarily related to reliability improvement and to address concerns about aging and obsolete equipment. In the 2016 preliminary capital budget, there are 120 projects with a total capital spend of $127 million dollars. Within that budget, only 7 projects with a capital spend of $6.5 million (5.1%) are associated with circuit load growth.
- Of the limited capital projects that address load growth, most also address other issues, such as aging infrastructure, obsolescence, and reliability. Also, it is typically cost effective to not only address the specific, immediate concern (i.e. a capacity constraint) but to also design and build additional circuit or substation capacity that would accommodate the ability to provide a backup to neighboring circuits and substations as well as apply distribution automation to further improve the circuit performance.
- Most distribution circuit capacity constraints are the result of a large new customer load or commercial or residential development. In these situations most circuit upgrades are required within a year or two of Eversource learning of the potential increase in load. This is generally not enough time to determine if other potential solutions are viable while leaving time to upgrade existing facilities. In cases with a longer lead time, the lack of certainty of the load actually materializing does not warrant investment at the time. Many, if not most, leads or inquiries suggesting new customer growth fail to materialize or are overstated. Premature investment in infrastructure or DG may not lead to any savings to customers.
- Additional distribution substation capacity requires 3-5 years of planning and investment. If land is required for the substation or line construction, typically this effort is initiated 5 years prior to the year of need. Engineering and permitting begins 2-3 years prior and construction begins 1-2 years before the project is needed. At the

same time, load growth is constantly monitored and the project need date and consequentially the need for investment is revised based on the latest projected need date. Pursuing DG as a solution, if unsuccessful, has the potential to compress the engineering and construction period resulting in higher costs or a single large customer load addition offsetting any demand reductions achieved by the solar resulting in no deferment or savings to customers.

- The deferment of a capital project has only limited value, i.e. the time-value of money, during which time the other benefits of the project which may include reliability benefits or lower operating costs would not be achieved.
- At this time, only two projected circuit overload has been identified in the Eversource five year forecast.

Q. Under what conditions is it possible for distributed generation resources to avoid or delay a utility capital project?

A. The ability of a DG resource to address a distribution capacity deficiency is influenced by the following factors: a) the need to make the distribution investment (i.e. is there a capacity deficiency on a particular circuit or substation for which the investment is not also needed to address obsolescence or reliability), b) the ability of the DG to reliably address the capacity deficiency (i.e. is the DG operational profile a good match for the load profile of the circuit), and c) the necessity for the required quantity of DG capacity to be operational in time to address the need. Unless DG development is targeted to the specific circuits and substations that have a forecasted capacity deficiency, and can reliably address the capacity deficiency, it is not appropriate to compensate DG resource on those circuits for the avoidance of distribution expenses.

Q. Please describe the planning criteria that Eversource uses to determine whether or not a capacity deficiency exists on a given circuit or substation transformer.

A. Eversource monitors the loading on substation transformers. When the loading reaches 85% of the transformer rating (i.e. a calculated rating taking the load cycle into account), an evaluation is performed to determine the best overall solution considering criteria such as cost, reliability, and ability to serve customer load. If the need of a capital investment is driven by the transformer capacity, the solution will be scheduled to be complete within a year of reaching the transformer rating. The interconnected 34.5 kV system is modeled with loading forecasted for 10 years. When an overload is forecasted, Eversource will determine the best overall solution and plan accordingly to have the solution in place when needed. Typically, the remainder of the distribution circuits are analyzed when the addition of customer load is proposed or if loading on reclosers or step transformers suggests that a circuit limitation may be imminent. Please see the Eversource LCIRP filing (Docket DE 15-248) for a more detailed explanation of this process.

In 2016, none of the Eversource bulk transformers are loaded to greater than 90% of nameplate and none of the 34.5 kV interconnected circuits are loaded to greater than 90% of conductor capacity. Note: the question of circuit capacity is complicated. Circuits consist of many segments constructed with different conductor sizes and number of phases as well as other components that may limit capacity such as reclosers and fuses that are a function of reliability, not conductor capacity. Therefore, each segment has its own capacity which may be due to conductor limitations, equipment limitations, or the ability to provide protective isolation points. In addition, each segment "capacity" cannot simply be added together as this would likely exceed the capability of an upstream segment.

Q. Please comment on the ability of DG resources to reliably address a capacity deficiency on a particular circuit or substation.

A. The ability of a DG resource to address a deficiency in distribution capacity is determined by the correlation between the production profile of the resource and the aggregate customer load profile of the circuit or substation. Consider solar PV resources. While each PV installation is unique, in general, the output of a PV resource will peak in the 1pm – 2pm time frame and begin to decline thereafter. In the 4pm – 5pm period, <u>even assuming optimal sunlight conditions</u>, the output may be only 30% - 40% of the rated capability of the project. In suboptimal sunlight conditions (i.e. cloud cover), the production will be further reduced. Also relevant is the fact that each distribution circuit and substation has a unique customer load profile. Some circuits are predominantly residential. Others are predominantly commercial or industrial. Most have a mix of customer types that influence when the peak load will occur. Based on a review of 2016 hourly data for Eversource's 34.5 kV substations, more than 50% experienced their peak in the summer months between the hours of 4PM and 7PM. Nearly 90% experienced their winter peak between 5 PM and 7 PM, during which solar PV is not producing any power.

Q. How could a utility planning engineer incorporate future DG development into their planning practices, such that a future capital project could be deferred?

A. Once a projected capacity deficiency is identified, utility planners begin the process of evaluating potential solutions. These solutions could include replacing transformers and upgrading circuits to achieve a higher capacity rating, but could also include less costly system reconfigurations that shift customer demand to an alternate source. If DG was considered as a potential solution, the quantity, type and location would need to be determined. There would need to be a tariff or program available to incent the development of customer-owned DG at these exact locations, and a means to somehow measure the benefit to be provided to determine what the proper incentive should be along with a means to reconcile that amount if the benefit does not materialize. Of course, the program would need to be successful, i.e. sufficient development would need to be guaranteed via firm contracts with strict timelines and penalties for non-performance. Unless this type of integrated planning was in place, it is not practical to rely on the random, scattered growth of intermittent, customer-owned DG resources to alleviate a forecasted capacity deficiency.

Q. Does the current net metering tariff design have any implications on the adoption of new technologies such as storage and demand control devices?

A. Yes. The article referenced below discusses the topic of "demand flexibility" and how traditional retail net metering tariffs provide minimal incentives for customers to invest in storage devices and demand control technologies. According to the article, net metering tariff design can lead to an increase in the adoption of these technologies.

"Utility Dive: How Solar can thrive in the post-net metering era" by Herman K. Trabish – November 3, 2015

IV. INCENTIVES TO INVEST IN RENEWABLE ENERGY RESOURCE

Q. Should net metered, renewable sources of power be compensated via a utility's net metering tariff for their environmental attributes?

A. Eversource is strongly supportive of renewable energy sources and believes that customers should be provided with reasonable opportunities to invest in DG. However, other programs are available to provide support for DG that do not rely on utility rate design. As a matter of public policy, renewable sources of power are eligible for a number of subsidy programs that are based on environmental attributes. Federal incentive programs, most importantly the Investment Tax Credit (ITC), provide a tax credit of up to 30% of the total cost to install a renewable energy project. This ITC is only made available to certain types of assets, presumably as a reflection of a desire to incent the adoption of these environmentally-friendly technologies. In New Hampshire, there are also a number of grant and rebate program administered by the NHPUC that provide subsidies to incent certain types of sustainable, small-scale power sources. The New Hampshire legislature also has enacted a "Renewable Portfolio Standard" (RPS) that provides the opportunity for certain types of renewable energy sources to earn compensation for environmental attributes via the sale of Renewable Energy Certificates (RECs). RECs are a source of revenue over and above that related to the sale of energy and capacity. Also, a number of municipalities around New Hampshire exempt some or all of the value of the solar facility from property taxes. These various types of incentives that subsidize renewable energy (i.e. ITC, grants, rebates, RECs and tax exemptions) are the proper vehicles by which to compensate these projects for their environmental attributes – not via the avoidance of just and reasonable electric utility rates. The environmental attributes of net metered resources are already compensated by these incentives. Therefore, the replacement net metering tariff need not, and should not, consider the emission profile and/or the carbon characteristics of these energy sources.

Q. Does the Eversource tariff proposal "provide reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair compensation for such locally produced power" as stated in the purpose statement to HB-1116?

A. Eversource believes their proposed tariff will continue to provide a reasonable incentive for customers to install DG. Exhibit RCL/RDJ-2 provides a simplified payback period analysis for a rooftop solar project. The analysis assumes an average project cost of $3530 per Watt and a project capacity factor of 15%.

The simple analysis indicates that, under the existing tariff program (full retail rates) a residential customer may recoup their investment in 7.6 years. This includes the 30% federal tax credit and the $2500 NHPUC rebate. It also assumes the customer is able to sell Renewable Energy Certificates (RECs) at $25 per REC. The 7.6 year payback represents a 13% return on the investment.

Under the Eversource tariff proposal (netting energy only at the current Default Energy Service rate of 10.95 cents/kWh) the payback period is increased to 11.6 years and the return drops to 9%. This is a reasonable payback period that provides continued opportunities for customer-generator facilities, which also provides fair compensation from the vantage of both the customer-generators and all other customers.

V. ADMINISTRATIVE PROCESSES RELATED TO NET METERING

Q. What comments do you have relative to Eversource's administrative processes that are required to implement net metering?

A. In general, Eversource believes the existing administrative processes that are used to respond to a customer's application for the net metering program are adequate. The NH Code of Administrative Rules Chapter Puc 900 provides adequate guidance for utilities and applicants relative to the review process. The order in Docket DE 15-271 (Examination of Electric Distribution Utility Interconnection and Queue Management Processes for Net-Metered Customer-Generators) provides additional procedural steps and requirements that were the result of a comprehensive stakeholder process. Eversource has also improved its webpages related to the DG interconnection process and the net metering queue. Overall, Eversource strongly believes we provide excellent customer service to DG interconnection applicants. The overwhelming majority of feedback is positive. In 2016, the average time between receipt of a completed residential application and approval of that application was under 8 days. The average time between the receipt of the required "certificate of completion" for the project and the date the Eversource net meter was installed is under 3 business days.

Eversource does, however, seek Commission approval for one process change in this docket. Consistent with Order 24,893 in Docket DE 06-061, on December 12, 2008 Eversource incorporated into its tariff the manual titled "Interconnection Standards for Inverters Sized Up to 100 KVA" (the "Standard"). The Standard allows Eversource to charge a "Supplemental Review Fee" of $125 per hour up to a total charge of $1,250. This fee applies only to facilities over 10 kVA and to smaller facilities that fail one of the simplified process screens. Eversource hereby requests that a flat fee of $125 be charged to all facilities sized 10 kVA and smaller, independent of any process screens. In support of this fee, Eversource provides the following justification:

Every application, even those of 10 kVA and smaller, requires intake and processing by Eversource administrative personnel. Applications are reviewed for completeness, saved to an electronic folder, added to a tracking database, etc. An Eversource engineer or technician evaluates each application to determine the size of the transformer feeding the customer and perform other screens (e.g. to ensure the point of interconnection is not made within the Eversource meter socket). The same technical staff reviews the project completion documents to ensure the facility was constructed and interconnected according to the submitted application documents. After the completion documents have been found satisfactory, Eversource field meter department staff visit each location to install the new net meter (at no charge). Lastly, Eversource billing personnel update the customer billing system to enroll the customer in the net metering service plan. Various emails are exchanged during the entire process between Eversource and the applicant. While a detailed cost analysis of this process has not been performed, the meter swap alone could warrant the $125 fee. The other application processing steps, in total, represent at least one full hour of labor. Eversource considers it appropriate to assess this fee to all applicants as a way to properly allocate the O&M expenses associated with this activity.