EXHIBIT
#59
DE 16-576

STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators	))))	Docket No. DE 16-576

REPLY TESTIMONY OF PAUL CHERNICK ON BEHALF OF CONSERVATION LAW FOUNDATION

Resource Insight, Inc.

DECEMBER 21, 2016

TABLE OF CONTENTS

I. Introduction

Q: Are you the same Paul Chernick who filed direct testimony in this proceeding?

A: Yes.

Q: What is the scope of your reply testimony?

A: I respond primarily to the direct testimony of the three utilities:

- Eversource (testimony of Richard C. Labrecque & Russel D. Johnson).
- Liberty (testimony of Heather M. Tebbetts).
- Unitil (testimony of H. Edwin Overcast).

I also respond to the evidence of the Office of Consumer Advocate (testimony of Lon Huber).

Q: Please summarize your response to the utility positions in this proceeding.

A: While the details in their evidence vary, the utilities generally follow the standard playbook of opponents of distributed generation, particularly distributed solar generation, that I described in my direct testimony. Some of the recurrent errors in their positions are the following:

- If solar output contribution at an important hour is less than maximum, they treat it as zero.
- They discount the value of any solar output.
- Rather than looking at solar contribution at the hours that actually stress the local distribution and transmission systems, they focus on minimally relevant hours, such as a class non-coincident peak (NCP) on a winter evening.

- They ignore the solar contribution at the hours that determine the share of the regional generation obligation and transmission costs paid by New Hampshire, the utility or the customers.
- They assume that power fed back to the distribution system by distributed generation will not reduce load on the distribution system or reduce the allocation of costs for transmission and generation capacity.
- Rather than analyzing benefits at current and near-term penetrations of solar and distributed generation, they hypothesize conditions that may occur many years in the future, with very high penetrations of distributed solar generation.
- They question whether any transmission and distribution costs are avoidable by reductions in load.
- Rather than compare the totality of the costs avoided by distributed generation to total net metering compensation, they argue about how a narrow slice of avoided costs compares to a particular net metering component.

Unfortunately, the utilities have offered the Commission primarily semantic distortion and misdirection, rather than serious analysis of the costs and benefits of distributed solar generation.

II. Underestimating the Benefits of Distributed Generation

Q: How do the utilities understate the benefits of distributed generation?

A: They understate the contribution of distributed generation to reducing almost all costs of serving customers, including generation costs (e.g., energy, capacity, RPS compliance, price reductions), transmission and distribution costs. They also attempt to distinguish between the system benefits of load reductions due to displacement of customer consumption and those due to energy fed back into the distribution system.[1]

A. Reductions in Host Load and System Load

Q: Which utility witnesses argue that power fed back to the distribution system by distributed generation is less valuable than reductions in the host customer's metered load?

A: For example, Ms. Tebbetts proposes that energy exported to the utility be credited with only the energy service charge, ignoring all the other benefits of the exported energy, such as reducing loads on the transmission and distribution systems, the allocation of regional transmission costs, and market prices for energy and capacity. Similarly, Messrs. Labrecque and Johnson assert that net metering customers are overpaid for exported energy, compared to market prices, again ignoring the other benefits of the exported energy.

Q: Do any of these witnesses justify this treatment?

A: No. They simply assume that power exported through the meter does not reduce the load on distribution and transmission equipment, the monthly loads that determine the allocation of regional transmission costs, or other costs.

[1] The comprehensive understatement of the benefits of solar output leads the utilities to suggest that net metering may violate PURPA's requirements that utilities payments for purchases from qualifying facilities be set at avoided costs (Labrecque and Johnson Direct at 17, Overcast Direct at 27–28). Without getting into the legal question of whether a net-metering credit is a power purchase, the complaints about PURPA compliance disappear if the corrected value of the solar output approximates the net-metering credit.

B. Generation Benefits

Q: What issues do the utilities raise with respect to the generation benefits of solar generation?

A: Various witnesses understate the value of solar for avoiding generation costs by:

- Disputing the eligibility of solar to be considered a generation resource.
- Ignoring the effect of solar generation in reducing the generation capacity obligations allocated to New Hampshire and the specific utility.
- Arguing that the value of solar generation for avoiding energy costs is consistently (as opposed to occasionally) lower than the prices that customers pay for power-supply.
- Ignoring the effect of distributed generation on market generation prices.
- Disputing the propriety of reflecting the environmental benefits of reduced fossil generation in the valuation of renewable generation.

I consider each of these issues below.

1. The Efficacy of Solar as a Generation Resource

Q: Do the utilities accept that solar photovoltaics are full-fledged generation resources?

A: Not entirely. Eversource witnesses Labrecque and Johnson suggest that solar generation is somehow inherently deficient. They say that:

> 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. (Labrecque and Johnson Direct at 14.)

> [At a particular peak hour,] 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. (Labrecque and Johnson Direct at 20.)

Q: Are these criticisms of distributed solar valid?

A: No, for a number of reasons. First, the output of solar facilities is as predictable as the path of the sun through the sky and the degree of cloud cover. The firm energy output of the fleet of New England solar generation over a month can be forecast with a high level of accuracy years in advance; the aggregate output in an hour in the next day is also highly predictable.[2]

Second, the output of any power plant is uncertain. When Millstone 3 or Seabrook trip off line, New England loses over 1,100 MW very quickly, and typically for a day or more. The same is true for some large fossil plants, especially where a single contingency can take multiple units off line, and for imports from Quebec. The variability and uncertainty of solar availability is different from that of large power plants and purchases, but not necessarily worse.

Third, while Messrs. Labrecque and Johnson find it "difficult…to consider customer-owned, solar PV as a source of firm capacity," the power planners at ISO-NE do not appear to have any such difficulty.[3] Even Messrs.

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[2] Solar output for a particular unit on an hourly basis is least dependable on days with variable cloud cover, but the geographical dispersion of the projects means that the aggregate output is much more certain.

[3] It is not clear what Messrs. Labrecque and Johnson mean by "customer-owned" solar. Their claims about the effect of intermittency would apply as well to the solar facilities listed in the ISO-NE Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report)—some of which are owned by customers, such as HP Hood, the Town of Agawam, City of Gardner, and the Franklin County Sheriff—as to the net-metered solar customers whose rates are the subject

Labrecque and Johnson note that “The ISO-NE Distributed Generation Forecast Working Group…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.” (Direct at 17.) The 2016 CELT Report shows that the summer claimed capability for each of the 33 solar plants ranges from 11% to 62% of their summer Network Resource Capability value (the plant’s maximum output at fifty degrees Fahrenheit or higher), averaging 41%. So ISO-NE accepts solar photovoltaic as firm capacity.

Fourth, Messrs. Labrecque and Johnson admit that net-metered solar does provide capacity that is as firm as any other resource:

> Intermittent DG can provide wholesale…capacity…..While most net metered projects are very small…they provide wholesale products...that are identical to those provided by large, central station generation resources.” (Labrecque and Johnson Direct at 16.)

This admission would seem to undercut all of Eversource’s complaints that solar is unreliable, intermittent, non-firm and unpredictable.

Q: Do Messrs. Labrecque and Johnson attempt to reconcile their dismissal of distributed solar generation with their agreement that behind-the-meter solar generation provide capacity identical to that provided by large, central station generation resources?

A: They seem to believe that there is a subtle distinction between firm capacity supply to ISO-NE and firm capacity supply to retail customers. Since all retail power suppliers depend on ISO-NE capacity resources to serve retail customers, this is a distinction without a meaningful difference.

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of this proceeding. The CELT Reports are available at www.iso-ne.com/system-planning/system-plans-studies/celt.

2. Reduction in New Hampshire and Utility Capacity Allocation

Q: Do the utilities address the extent to which distributed solar generation reduces the allocation of generation capacity obligations to New Hampshire consumers?

A: The utilities understate the extent to which solar energy (whether it reduces the customer's purchases from the utility or flows back to the distribution system) reduces New Hampshire generation capacity obligations. None of the utilities recognize that the average kWh of solar energy displaces more generation capacity than the average kWh of residential customer usage. For example, Dr. Overcast says that "there will be a subsidy in the generation and transmission portion of the rate simply because the solar PV capacity…will not be coincident with the system or class peak demand" (Overcast Direct at 20).[4]

Q: How are New Hampshire's capacity obligations reduced by solar energy that flows back to the utility at the New England annual peak load?

A: ISO-NE reconciles the profiled customer loads in the peak hour to the total power delivered to the utility in that hour. Distributed generation that reduces the customer's load for the billing period that includes the peak directly reduces the customer's profiled load at the peak hour. Distributed generation in New Hampshire that feeds back into the distribution system (and is not recognized as capacity in the forward capacity auctions) reduces the load obligations of the customers in the zone, by reducing the reconciled profiled loads or potentially the loss factor. The basic reconciliation approach is that

[4] Dr. Overcast does not define the "system" peak to which he is referring, but the relevant system peak for generation costs is the New England coincident peak. His reference to the "class peak demand" probably describes his incorrect view of the loads driving transmission costs, which I discuss in Section II.C.

the hourly difference between (a) the hourly metered loads delivered from the ISO-NE bulk system and (b) the total system estimated hourly loads is allocated to energy service providers in proportion to their sales to profiled customers.[5]

Eversource notes that "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." (Labrecque and Johnson Direct at 19.) That statement is correct, but irrelevant. At that same hour, the 16 facilities were also producing 230% of their average annual output.

In contrast, at the 2015 New England peak hour, the New Hampshire load was 2,169 MW, 1.62 times the average New Hampshire load in 2015. The peak reduction associated with each kWh of annual solar output was 1.42 (= 2.3 ÷ 1.62) times as great as the peak load associated with each kWh of New Hampshire energy usage. The capacity value of the average kWh of solar generation is much higher than the capacity cost of a kWh of customer load.

Q: Was the 2015 result atypical?

A: If anything, the 2015 result understated the peak contribution of solar. The ISO-NE peak load hour for 2016, which determines the allocation of capacity for 2016/17, occurred on August 12 at hour-ending 3 PM. At that time, the 20 non-tracking solar projects whose hourly output was provided in Attachment Staff-NHSEA-1 for August 21, 2015 through August 20, 2016 were generating an average of 3.61 times their average output for that one-year period.

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[5] Eversource's process for the reconciliation is described generally in the "Terms and Conditions for Energy Service Providers" section of its tariff NHPUC No. 9 – Electricity Delivery, specifically page 39. Central Maine Power provides more detail on its similar process at www.maine.gov/mpuc/electricity/ElectricSupplier/Ch321_Rpt_CMP2.pdf.

The ISO-NE 2016 Forecast Data File projects that New Hampshire solar would reduce peak load by three times as much as average load in 2016, rising to the 3.5 to 3.6 range after 2022.

Q: If a net-metering customer exactly offset its energy use with solar output over the course of the year, would the solar facility contribute more or less to the peak hour than the customer used?

A: The typical residential customer represented in Eversource's load profile used 1.1 kWh in the 2015 peak hour (a July weekday in the hour ending at 5 PM), which is 1.33 times as much energy as over the year.[6] The solar output at peak, per annual kWh produced, was 170% (= 2.30 ÷ 1.33) of the residential consumption at peak, per annual kWh used. The 2016 peak hour (an August weekday in the hour ending at 3 PM), the typical residential profile was again using 1.1 kWh, and the solar systems were producing 270% (= 3.61 ÷ 1.33) as much power at peak as the residential customer would have been using, per kWh of annual energy. So a customer who exactly offset their energy usage over the year with solar generation would reduce load at peak by much more than the customer's peak load. That additional reduction in peak load would reduce the capacity requirements for New Hampshire consumers, including those without solar generation.

In terms of contribution to generation capacity, Dr. Overcast has the facts backwards. Solar output is more heavily weighted toward the annual peak than is load, so the owners of solar generation subsidize other customers.

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[6] www.eversource.com/Content/nh/about/doing-business-with-us/energy-supplier-information/electric---new-hampshire. I estimated the average hourly load by multiplying Eversource's weekday hourly profile loads for each month by five, multiplying the weekend hourly profile loads for each month by two, adding across months, and dividing by the number of observations (7×24×12 months). The resulting average was 0.83 kW.

3. Generation Energy Value

Q: How do the utilities understate the energy benefit of distributed generation?

A: Eversource witnesses Labrecque and Johnson make an inapt comparison between Eversource's current default generation service and a subset of after-the-fact costs and assert that net-metering customers would shift loads to other customers. Liberty witness Tebbetts argues that including the entire energy service charge in the credit for energy exported to the distribution system shifts costs to other customers (Direct at 18).

Q: Please explain why the Eversource energy-price comparison is inapt.

A: Messrs. Labrecque and Johnson compare Eversource's 10.95¢/kWh 2015 price for default generation service to the 2015 real-time hourly energy prices weighted by the output of a sample of solar installations, which they estimate to be $38.4/MWh, plus the capacity revenue that the facilities would have received if they had participated in the 2015/16 capacity market, which they compute to be another $6.24/MWh, ignoring line losses. This comparison is technically incorrect and unrepresentative for the following reasons:

- Unlike retail competitive power suppliers, Eversource prices its generation service to recover the embedded costs of its legacy plants. In the last couple years, the market price of energy has fallen dramatically, and Eversource's generation price is significantly higher than market prices. Since Eversource is in the process of divesting its generation resources, the mismatch between the default rate and market prices will disappear.[7]

- Even for market-based power-supply arrangements, calendar year 2015 real-time spot prices were much lower than the prices that suppliers would have charged, based on forward market prices when they would have procured power and set contract prices. For example, the simple average of the monthly on- and off-peak forward prices for the New Hampshire zone for the months of 2015, as posted on July 1, 2014, was over $67/MWh, or at least 70% higher than the real-time price reported by Eversource.[8] Any solar generation known to a power supplier in 2014, when it was procuring power it had committed to deliver in 2015, would have reduced the supplier's procurement of energy and capacity.
- As Messrs. Labrecque and Johnson note (Direct at 14), default service (and competitive power supply) includes the costs of ancillary services, RPS compliance, risk management, and overheads. The reduction of energy consumption by the net-metering customers would proportionately reduce the renewables that Eversource would need to acquire to meet the RPS (even if the customers choose to retire their

[7] I assume that the portion of the current Eversource default rate due to costs that are above market in the longer term would move to the stranded cost charge. The Commission will need to decide the ratemaking treatment of that charge, for net metering and other customers.

[8] The forwards were not much lower on December 1, 2014 than they were in July 2014. The actual spot energy prices (whether real-time prices or day-ahead prices charged to suppliers for most of their spot purchases) will vary from the energy prices incorporated in rates fixed in advance, some years the spot prices are higher than the forward prices. The large drop in prices from the 2014 forwards to the 2015 spot price is unusual. Liberty procured market-price power supply and charged 14.545¢/kWh for November 2014 to April 2015, and about 8¢/kWh for May to November 2015.

RECs), as well as the amount of hedging Eversource would need to do. Most ancillary services are allocated to load-serving entities (including Eversource for its default service, the default service providers for Unitil and Liberty, and competitive suppliers) in proportion to various measures of hourly load obligation, which would be reduced by reductions in metered consumption of net-metering customers and by the reduction in metered wholesale load due to energy fed back into the distribution system.[9] Since Messrs. Labrecque and Johnson ignore the value of solar in avoiding ancillary, RPS, and risk-management costs, they have overstated the difference between the energy service rate and the energy-cost reduction of solar.

- Messrs. Labrecque and Johnson used 7.5% energy losses, rather than the 7.75% Eversource applies to residential metered energy on its Energy Supplier Information page. The same page shows an upward adjustment of 8.67% for line losses on capacity, but Messrs. Labrecque and Johnson included no losses. Using Eversource's official loss values would increase the comparison price to $45.25/MWh.
- Even those line losses are just the average line losses on the distribution system. The marginal line losses would be even higher.
- Eversource assumed that the net-metered solar installations bid into the regional capacity market and were credited with their qualified summer and winter capacities. No New Hampshire solar facilities are found in

[9] The allocation factors are described in the ISO-NE monthly Wholesale Load Cost Reports (https://iso-ne.com/markets-operations/market-performance/load-costs). For example, regulation is allocated to all energy and forward reserves to on-peak energy, while second-contingency Net Commitment-Period Compensation (NCPC) and real-time reserves are allocated on to the zones and days on which the services are required.

ISO-NE's list of generation resources that participated in FCA 6 for the 2015/16 year.[10] The net-metering solar installations would have been treated as reductions in load, which would be more valuable than participating as supply in the capacity market, since they would be credited with their contribution at system summer peak, avoided losses, and avoided the price per kW of load, which is higher than the price paid per kW of supply.[11]

Q: Are Messrs. Labrecque and Johnson correct that the net-metering customers would shift supply costs to other customers?

A: No. For market-based generation rates (set by a competitive retail supplier, or a wholesale supplier to Liberty, Unitil or shortly Eversource), the supplier sets the rate in advance and guarantees it for a fixed period of months. If the supplier misestimates the amount of capacity and energy required to meet its customers' loads, net of the reduction in sales to the net-metering customers and reflecting the reduction in zonal load due to solar energy exported by those customers, the supplier will either sell the excess or purchase the shortfall and absorb the loss or gain. None of the costs flow to the other customers.[12]

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[10] Forward Capacity Auction 2015 - 2016 Obligations, www.iso-ne.com/static-assets/documents/markets/othrmkts_data/fcm/cal_results/ccp16/fca16/fca6_monthly_ob.xlsx.

[11] This is always true due to the reserve margin included in the price charged to load. In addition, FCA 6 procured more capacity than required and the supply price was derated by about 10%.

[12] Similar effects occur continually for market generation suppliers, as energy use changes with weather and other factors and as customers not bound by contract switch suppliers. Severe weather increases energy requirements and also the price of the extra energy that the suppliers must obtain. Mild weather decreases energy requirements and also the price of the surplus energy that the suppliers must dump into the market. Wholesale suppliers for default service may both

In the longer term, the suppliers will recognize the effect of the net-metering supply on its energy and capacity obligations and set prices to reflect the loads that they expect to serve.

If the distributed generation feeds energy back into the distribution system, it reduces the required energy delivery from the regional transmission system to the New Hampshire sub-transmission and distribution system. That reduction in energy delivery will flow through to New Hampshire consumers through the ISO-NE reconciliation process.

Q: Is Ms. Tebbetts correct that including the entire energy service charge in the credit for energy exported to the distribution system shifts costs to other customers?

A: No. She may believe that net-metering customers shift costs to other customers by not paying reconciliation charges and receiving reconciliation credits (Direct at 18). I do not follow Ms. Tebbetts's reasoning, since the excess generation exported by the net metering customers will reduce the total energy-service bill for Liberty customers. Nor does she explain why she believes that these reconciliation components will be charges more often than credits.

4. Effect of Distributed Generation on Market Generation Prices

Q: Do the utilities acknowledge that distributed solar generation reduces prices for generation services?

A: No. None of the utilities recognize these benefits, for ISO-NE capacity prices, market energy prices, or the effect of load reductions on the demand for and

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gain and lose customers, and are likely to gain customers when market prices are rising and lose customers when market prices are falling. Supplier price offers reflect those risks.

price of natural gas, which then has a significant effect on the price of electric energy.

5. *Environmental Benefits*

Q: Do the utilities acknowledge that distributed solar generation provide environmental benefits?

A: Messrs. Labrecque and Johnson acknowledge that renewable energy provides valuable benefits, but claim (Direct at 28) that renewables are compensated for these benefits through the following programs:

- the Federal investment tax credit,
- unquantified New Hampshire "grant and rebate program[s],"
- the New Hampshire Renewable Portfolio Standard and the resulting renewable energy credits (RECs), and
- exemption of "some or all of the value of the solar facility from property taxes" in some New Hampshire municipalities.

They do not demonstrate that these programs, or the portions available to all Eversource New Hampshire customers, are motivated primarily by environmental benefits (as opposed to promoting job creation and innovation, for example), or that the programs provide support for distributed solar equivalent to its environmental benefits for New Hampshire.

Most importantly, Eversource does not propose any mechanism for ensuring that all distributed renewable generation actually receives REC revenue.

C. Transmission Benefits

Q: Do the utilities acknowledge that distributed solar will reduce transmission costs for New Hampshire consumers?

A: No. In Exhibit RCL-RDJ-1, Eversource assumes that all transmission costs are stranded by load reductions due to solar generation behind the meter, and that no transmission costs are avoided by power delivered to Eversource. These assumptions could only be true if the solar output never coincided with the monthly load that sets Eversource New Hampshire's transmission allocation. Messrs. Labrecque and Johnson claim that load reductions due to solar generation are too small to affect transmission planning, but do not address the allocation of regional transmission costs.[13] As I explained in my direct testimony, and as I update below, that is not correct.

On behalf of Liberty, Ms. Tebbetts claims that "Because net metering customers 100 kW and smaller avoid paying for all the transmission charges allocated to Liberty Utilities to the extent of their generated kWh, those charges are shifted to all other customers through the reconciliation calculation." (Tebbetts Direct at 10.) She repeats this claim at page 17 of her direct testimony. Liberty provides no analysis to support these assertions. Ms. Tebbetts's rate-design proposal treats energy delivered to the utility as providing no transmission benefit. As with Eversource, these assertions are contrary to fact.

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[13] Their argument that solar load reductions will be vanishingly small at the summer peaks that drive most transmission additions seems to be inconsistent with Eversource's concern that net-metered solar will become so prevalent as to shift enormous costs to other customers (e.g., the 50% penetration assumed on page 14 of the Direct Testimony of Labrecque and Johnson).

Unitil witness Overcast asserts that he "proves that there are no avoided transmission or distribution costs" (Overcast Direct 10). I cannot identify any place in his testimony where he does anything of the sort, but he does make unfounded claims about solar generation and transmission cost causation.

As he did with respect to generation, Dr. Overcast complains that customers with solar generation receive a subsidy because maximum solar output is not coincident with class peak and that "only a portion of the installed kW will be coincident with an afternoon peak as it occurs currently. The coincident amount will be between 2% and 24% of the installed kW on average and even lower on a peak day because of the extreme high temperature." (Overcast Direct at 20.) He seems to be under the misapprehension that transmission costs are determined by class non-coincident peaks, perhaps because he might use non-coincident peaks to allocate transmission costs among classes. In reality, Unitil's transmission charges are determined by its peak loads coincident with the monthly peaks of the so-called local network, which includes a large portion of New England, not by class peaks. Solar contributes heavily to the afternoon peaks in the spring and summer, but not to the winter evening peaks in other months.

Q: Is there any reasonable doubt that load reductions avoid transmission costs?

A: No. There are three effects of load reductions:

- Lower loads at peak times will result in lower requirements to reinforce and add transmission lines and substations. These are the direct demand-related avoided transmission costs traditionally included as avoided or marginal transmission costs, estimated from the transmission investment and load growth over a period of several years.

- Lower load at near-peak times and prior to the peak will also slow the aging of lines and substations, and increase the peak capacity of existing facilities. These energy-related avoided costs may be partially captured in the traditional estimate of marginal transmission costs, although they are erroneously assumed to be due to one (or a few) annual hours, rather than usage in lower-load hours.
- Perhaps most importantly, reducing monthly peak loads will decrease the allocation of regional New England network transmission costs to the so-called local networks of the New Hampshire utilities and reduce the share of the local network costs (both for regional facilities and local facilities) allocated to the New Hampshire utilities and their customers. This avoidance of embedded transmission costs is usually ignored in the estimation of marginal transmission costs.[14]

Q: Have the New Hampshire utilities estimated the direct transmission costs avoidable by load reductions?

A: Yes. In the most recent energy-efficiency plan, the utilities provided estimates of avoided transmission and distribution costs, reproduced in Table 1. The energy-efficiency plan does not explain how the utilities estimated these avoided costs, and most importantly, whether they included the effect of reduced allocations of regional and local network costs.

[14] The traditional methods for estimating marginal transmission costs are designed for free-standing vertically-integrated utilities that own their own transmission. In some RTOs, including ISO-NE, a large portion of transmission is treated as part of the regional network and its allocated to all load in the RTO.

Table 1: New Hampshire Utility Estimates of Avoided T&D Costs (2015 $/kW-year)

	Residential	C&I
NHEC	$139	$139
Liberty	$123	$89
PSNH	$68	$68
Unitil	$79	$79

Source: 2016 New Hampshire Statewide CORE Energy Efficiency Plan, Attachment C

Q: Do you have additional information about the allocation of transmission charges among utilities, and the loads that determine the transmission costs borne by New Hampshire customers?

A: Yes, since my direct testimony, I have learned more about the allocation of transmission network costs. In my direct testimony, I said that "the allocation of transmission costs is based on monthly zonal peaks" (Chernick Direct at 10), when I should have said "the allocation of transmission costs is based on monthly peaks on the Local Network." In the terminology used by ISO-NE, a Local Networks consists of the transmission equipment owned by a transmission owner and is not necessarily local in a geographic sense.

Eversource and Unitil (as well as the New Hampshire Electric Coop) are part of the Northeast Utilities Service Company local network, which remains separate from the NSTAR local network for the purpose of transmission cost allocation. The NU local network serves Connecticut (over 60% of network load), western Massachusetts (about 13% of load) and New Hampshire (under 25% of load), plus a small amount of load in Maine. Table 2 summarizes the timing of the NU local network monthly peaks over the last 11 years. The summer local network peaks are somewhat more heavily concentrated in the daylight hours of April to September than are the New Hampshire zonal peaks summarized in Table 2 of my direct testimony.

Averaging the ratio of solar output (from the Staff-NHSEA 1-1 sample) at each of the NU local network monthly peaks for September 2014 to August

2016 results in an estimate of an average solar output of 91% of average annual solar output.

Table 2: Northeast Utilities Local Network Peaks, by Hour Ending and Month January 2006 to October 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
11	-	-	-	1	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	1	1	1	-	-	-	-	-
15	-	-	-	1	-	3	3	6	-	-	-	-
16	-	-	-	1	4	2	4	3	4	-	-	-
17	-	-	-	-	4	4	3	2	5	-	-	-
18	2	-	-	-	2	1	-	-	-	-	10	8
19	9	11	11	-	-	-	-	-	-	9	-	2
20	-	-	-	5	-	-	-	-	2	2	-	-
21	-	-	-	3	-	-	-	-	-	-	-	-

Q: You stated that Eversource and Unitil are served by the Northeast Utilities local network. Which local network serves Liberty?

A: Liberty is served from the New England Power local network, the transmission system owned by National Grid.

Liberty apparently did not understand the concept of a Local Network for transmission service, and claimed in discovery that it was its own local network (CLF-Liberty 1-1) and elsewhere that its transmission charge is determined by its load at the monthly peak hours for all of ISO-NE (CLF-Liberty 1-19). Neither of these answers is correct.

Since Liberty did not provide the actual times of the monthly peaks for the New England Power local network, and since ISO-NE does not publish those times, I cannot conduct the same analysis for Liberty that I performed for Eversource and Unitil in Table 2. However, the bulk of the New England Power load is in Rhode Island and eastern and central Massachusetts, so the peak hours on that local network are likely to be similar to the peak hours on the NU local network, or perhaps a bit earlier.

D. Distribution Benefits

Q: Do the utilities recognize that solar generation will reduce distribution costs?

A: No. Eversource, Unitil and Liberty take essentially the same position with respect to distribution as they do to transmission, and similarly treat all distribution costs as unavoidable.

Q: Do you have any information on the timing of distribution loads to add to the data you presented for the Eversource substations in your direct?

A: Yes. I have performed an analysis of the amount of solar generation for the 25 feeders for which Liberty was able to provide the time of the peak loads.

Twenty-one of those feeders experienced their peak load in hours in which the New Hampshire solar facilities were producing some power. Two feeders peaked when solar generation was below average, five when solar generation was between average and twice average, seven when solar generation was between two and four times average, and seven when generation was over four times average. On average over the 21 substations, solar was generating over twice its average output at the time of the annual peak.

At the time of the average megawatt of the peaks for the 49 Eversource substations, the solar plants were producing about 110% of their annual average output.

Unitil did not provide comparable data on the timing of substations, so I was not able to perform the same analysis for that utility.

Q: Do the utilities accept that distributed solar generation reduces distribution costs?

A: Not really. They raise doubts about whether any load reduction can avoid distribution costs, and separately doubts about whether the load reductions due to solar generation reduce distribution peaks.

Q: How does Eversource misrepresent the effect of solar output on distribution equipment peaks?

A: In discussing feeder peaks and avoidable distribution capacity, Messrs. Labrecque and Johnson assert that:

> 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. (Labrecque and Johnson Direct at 24.)[15]

This passage introduces multiple errors and confusions. First, it is curious that Eversource makes these claims about the timing of its feeder peaks, considering that it claims to have no information on the timing of the peak loads on its feeders (CLF-Eversource 1-23). The best proxy we have for the timing of Eversource feeder peaks is the data it provided on substation peaks in Staff-Eversource 1-25, the source of Table 3 in my direct testimony, and for the data on substation peaks I present in the rest of this answer.

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[15] Mr. Huber cites these misleading numbers (CLF-OCA 1-33) to support his assertions about the timing of peak loads on secondary lines between line transformers and residential customers, as well as costs related to billing and metering (Huber Direct at 27). The timing of the feeder peaks does not necessarily coincide with the timing of the peak loads on secondary lines, and peak loads have no effect on billing and metering costs. Mr. Huber did not provide any basis for his speculation about secondary peaks or his assertion that the timing of solar output affects billing and metering costs.

Second, Messrs. Labrecque and Johnson overstate the "mismatch" between substation peak loads and solar generation, by suggesting that solar is useless except at its peak output. Solar generation does "begin to wane prior to" the 5–7 PM period, but it remains well above average for most of this period.

Third, while Eversource experienced about 400 MW of annual 2015 substation peaks in the summer from 5 PM to 7 PM, it did not report any summer substation peaks in the hour ending at 8 PM. It is not clear whether any Eversource feeders peak in the hour ending at 8 PM.

Fourth, Eversource experienced almost 1,000 MW of summer substation peaks in the hours from noon to 5 PM, when solar output is about two to four times the annual mean. The minority of peaks in the "5:00 to 8:00 pm" period hardly represent the general pattern.

Fifth, while solar output is lower in the early-evening hours than at midday, they are not zero. In July, the average output in the hour from 5 PM to 6 PM is over 92% of the annual mean; in the next hour, that average drops to 33%. A contribution less than the maximum for the day or year is not inherently unimportant.

Messrs. Labrecque and Johnson further confuse the issue when they assert:

> 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, even assuming optimal sunlight conditions, the output may be only 30% - 40% of the rated capability of the project…. 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. (Labrecque and Johnson Direct at 26–27)[16]

Messrs. Labrecque and Johnson present this selective information about the timing of the summer substation peaks as if that indicated that solar generation were ineffective at reducing loads on substation peaks. The implication is incorrect. While Staff-Eversource 1-25 does show about 40% of Eversource's New Hampshire substation peak load occurring after 4 PM in July, August or September, half of that occurs in the hour from 4 to 5 PM, and about a quarter each in the hours ending 6 PM and 7 PM.[17] These are not the peak hours for solar output, but they are still higher-than-average hours.

- In the hour ending 5 PM in July, New Hampshire solar plants produce about 2.7 times their average output; by September, that value has declined slightly, but is still over 1.9 times the plants' average output.
- In the hour ending 6 PM, the solar facilities continue to produce 1.8 times their annual average in July and about 1.5 times the annual average in August.[18]

[16] Messrs. Labrecque and Johnson may have been referring to the number of substations, rather than the amount of load on the substations, which would overstate the importance of very small substations. They may also have been describing the winter maximum load of substations that experience their peak load in the summer. So their statements may be misleading and irrelevant, rather than technically incorrect.

[17] Staff-Eversource 1-25.

[18] No substations peaked between 5 and 7 PM in September.

- In the hour ending 7 PM, the solar facilities continue to produce 0.9 times their annual average in July and about 0.7 times the annual average in August.

The contribution of the solar to reducing substation peak loads in the period from 4 to 7 PM, weighted by the share of substations peaking in each month, is about 1.7 times the average solar output. Another 25% of annual peak loads occur in the summer from noon to 4 PM, when solar output is typically three or four times the annual average.

Eversource's claim about the winter peaks similarly misstates the situation. In fact, only about 15% of the substation peak load occurs in the winter evenings, and about the same amount of substation annual peak occurs in the winter from 8 AM to 2 PM, when the solar systems would typically be generating more than their average annual output.

Q: What does Liberty assert about the value of solar for reducing distribution costs?

A: Liberty asserts that its solar generation cannot reduce distribution costs, since solar does not reduce peak loads on the distribution system:

> The Company builds its distribution system to meet peak demand.…[P]eak demand…typically does not occur when a solar installation is generating its peak output. For example,…our residential customer class peaked on February 15, 2015 at 6:00 p.m. (Tebbetts Direct at 9)

It is conceivable that Ms. Tebbett is correct about the timing of the residential class peak, but Liberty has no way to monitor the actual load of the residential class, so this statement is an estimate, not a fact. More importantly, there is no feeder or substation that serves Liberty's residential entire residential class and no other class. Each feeder and substation serves only a portion of the residential class,[19] and most serve multiple classes, so the hour of the residential class maximum load (even if Liberty knew that hour) does not drive much, if any, distribution costs.

Most importantly, Ms. Tebbett's assertion is not supported by the metered data that Liberty provided. Of the 25 feeders for which Liberty provided data on monthly peaks, only two experienced their peak loads in February; many of the feeders that peak in other seasons have 80% or more residential load. As I explain on page 21, most of the feeders peak at times when solar generation would help reduce load. So even if Ms. Tebbetts is correct about the time of the residential peak, she is wrong about whether solar output coincides with the peak loads of distribution equipment serving residential customers.

Q: What is Unitil's position on the benefits of distributed generation for distribution costs?

A: Dr. Overcast asserts that solar distributed generation cannot reduce loads on the distribution system:

> I also show that there are no avoided distribution costs as the result of solar DG customers on the system. This conclusion is theoretically sound because the non-coincident peak demand on the distribution system does not occur when solar DG customers are delivering excess generation to the system, and there is no time diversity of solar DG production as there is with customer load. This is equivalent to stating that DG customers have their highest class NCP based on generation delivered to the system rather than net load on the system. (Overcast Direct at 6.)

His conclusions appear to be based on his presumption that the customer's contribution to distribution costs is determined by its maximum non-diversified load, whenever that occurs, and that power flowing out to the

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[19] This is true for any but the tiniest utilities, but is particularly obvious for Liberty, which has four non-contiguous service territories in New Hampshire.

distribution system does not reduce loads on transformers, feeders, or substations.

> From a cost perspective, the delivery cost is the same for these two customers [both with the same 8 kW maximum non-diversified load and the same energy consumption, one with 8 kW of solar generation capacity] based on the assumption of identical demand. Actually, it is likely that the solar DG customer will cause a higher demand on the system in export mode than in load mode (Overcast Direct at 19.)

Q: Are Dr. Overcast's assertions plausible?

A: No. As I have explained in my direct testimony and above, the customer's maximum load affects almost no distribution costs, which are driven by loads at the times that contribute to equipment stress. Solar output actually reduces flows through many substations and down many feeders at the time of their maximum loads. Dr. Overcast's assertion that excess solar output "will cause a higher demand on the system" than the customer's maximum draw from the system is unfounded and internally inconsistent, for a number of reasons. First, most of the distribution system is highly diversified, with each substation and feeder serving thousands of customers.[20] So long as other customers are using more energy than the solar installation is putting into the feeder, the solar export results in a reduction in demand on the feeder, not additional demand. Second, Dr. Overcast assumes that the customer with the solar installation still draws 8 kW from the distribution system at some point in the year, presumably at night when solar output is zero. The 8 kW solar array cannot cause a demand on *any* part of the distribution system higher than 8 kW, and it can only put 8 kW on the portion used only by this customer, which might be a span of secondary for some customers and nothing for many customers. Even for that

[20] The same is true for most line transformers, although the number of customers sharing a transformer is much smaller than the number sharing a feeder or substation.

small amount of distribution equipment, the export could be 8 kW only if the customer's load at the maximum generation output were zero: the refrigerator idle, the internet router and wifi hub turned off, all vampire loads zeroed out.

III. Errors in Proposed Rate Designs

Q: Do you have any comments on the rate designs proposed by the utilities and others for net-metering customers?

A: Yes. I have responses to the following rate designs proposals:

- Eversource and Unitil proposals to impose demand charges on net metering customers.
- The proposals of Unitil and the OCA to implement quite different time-of-use rates for distributed generation customers.
- The complex rate redesign proposed by the OCA (including an export charge and a non-bypassable charge, along with other non-bypassable components).

A. Demand Charges

Q: What position do the utilities take regarding demand charges?

A: Both Eversource and Unitil propose demand charges for net metering customers. The Eversource panel asserts that:

> 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. (Labrecque and Johnson Direct at 8.)

Unitil witness Overcast observes that "Customers cause distribution demand costs not based on the coincident peak demand but on non-coincident peak demands" and describes correctly the diversity in the peak times for substations and feeders. (Overcast Direct at 24.) He then leaps to the conclusion that "To correctly reflect the matching principle, [utilities should use] maximum customer demand whenever it occurs to recover distribution costs" (ibid).[21]

Liberty does not propose demand charges.

Q: Is Eversource's characterization of demand charges factually correct?

A: No. The customer's "monthly or annual highest kW" is rarely, if ever, an "appropriate determinant of the cost to serve." As I explained in my direct testimony, various types of costs are determined the customer's load at the time of "monthly or annual highest kW" *on a particular piece of equipment*, and by other high-load hours on that equipment, or at the time of "monthly or annual highest kW" *on the local network or the New England region*. The Eversource witnesses conflate these types of relevant peak or near-peak loads with the customer's maximum non-diversified load, which may not occur during an important hour for any demand-related cost determinant.

I described the numerous reasons that demand charges are inappropriate for recovering almost any cost component, in my direct testimony. My observations are echoed by those of Patrick Bean, who has offered testimony on behalf of EFCA.

[21] Dr. Overcast says that "the matching principle of cost causation is a fundamental principle for setting just and reasonable rates. That is, rates must be set so that customers pay for those costs they cause on the system" (Overcast Direct at 17.)

It is also important to recognize that Messrs. Labrecque and Johnson propose to use the demand charge to recover costs that the net metering customers actually allow Eversource to avoid.

Q: Are demand charges effective in implementing Dr. Overcast's "matching principle"?

A: No. The customer's "maximum customer demand whenever it occurs" is a poor proxy for the costs the customer causes. Distribution costs are caused by the customer's contribution to the peak loads on substations and feeders, which are spread over many hours, and are most effectively and equitably recovered through time-of-use rates for the hours that cover the times of those peaks.

Dr. Overcast's assumption that demand charges reflect cost causation may result from a long-standing confusion in utility terminology between costs that are fixed in the short term and costs that are fixed and unavoidable. When Dr. Overcast says that "most of the system's delivery costs to serve its customers are fixed and do not vary with the units of energy sold" (Overcast Direct at 21), he may be thinking that the costs are fixed and not avoidable. While Unitil's transmission charges are not fixed even in the short term (since they are determined by monthly loads coincident with the NU local network peak), distribution costs are fixed in the short term, but variable over a period of years as load growth requires capacity upgrades and as high loads accelerate equipment aging.

B. Time-of-Use Rates

Q: What parties propose time-of-use rates for residential net metering customers?

A: The OCA and Unitil propose time-of-use rates. OCA proposes bidirectional time-of-use charges for some delivery costs, while Unitil proposes a time-of-use rate for generation services.

Q: If the Commission were to implement time-of-use rates, to which customers should they be applied?

A: As an economic matter, the costs of time-varying rates (including the metering and billing technology and consumer education and service) are most easily justified by the largest customers with the largest usage. Hence, a utility normally should start by shifting its largest commercial and industrial customers onto TOU rates, followed by the largest residential customers and then smaller customers. At each step, the Commission should verify that the expected savings from load shifting and conservation justify the costs of the metering. As non-residential customers are moved to time-varying rates, the Commission should reduce the inefficient demand charges and recover those revenues though time-varying energy rates that better reflect the timing of loads that drive generation, transmission and distribution costs.

Net metering customers ideally should be moved onto time-varying rates at the same time as other customers in their rate classes.

Q: How much would it cost to implement statewide time-varying metering and billing for residential customers?

A: Eversource does not have any estimate of the cost of implementing TOU rates (CLF-Eversource 1-3).

Q: Has the OCA proposed appropriate periods for a TOU rate?

A: No. The OCA proposes peak periods that are not based on an analysis of the distribution of cost drivers. Specifically, the proposed peak period of 2 PM to

8 PM all year round does not reflect the timing of the loads that cause any of the following:

- Allocation of generation costs to New Hampshire consumers, which is the result of loads in June to August, from 2 PM to 5 PM (see Table 1 of my direct testimony). Reduced usage in these loads by customers whose capacity obligations are derived from ISO-NE proxies will benefit all customers in their class, and power fed back into the distribution system at these hours by distributed generation will reduce the capacity obligation for all New Hampshire load.
- New England capacity prices, which are determined by the forecast net load on the ISO-NE transmission system at the annual peaks, which occur at 2 PM to 5 pm in July and August.
- Allocation of transmission costs to New Hampshire, which is the result of loads in each month, from 1 PM to 6 PM in May–August, 5 PM to 7 PM in October–March, and a blend of those times in April and September (see Table 2, above).
- Need for reinforcing the transmission system, which is driven primarily by the summer peak loads.
- Need for reinforcing the distribution system, which is the result of loads spread out over many time periods, as illustrated in Table 3 of my direct testimony. The Eversource substation peaks are heavily concentrated in the months of July to September; on an annual basis, the substation peaks in the hour before Mr. Huber's proposed peak are four times greater than the substation peaks in the last hour of his proposed period.

Mr. Huber's proposed peak period is also not designed to reflect differences in zonal energy prices over the hours and months.[22] It appears that efficient time-of-use periods would have different peak periods in at least two seasonal periods, and prices should also vary by season. Higher prices in the summer afternoons, reflecting the hours critical to the allocation of generation and transmission costs and causation of distribution costs, would tend to encourage installation of solar generation facing more west than south.[23]

The record in this case does not support selection of any particular TOU periods or rates. The Commission should refer these issues to the stakeholder process I describe in Section VI.

C. OCA Rate-design Proposal

Q: What is the OCA rate-design proposal for net-metered customers with solar generation?

A: That proposal is laid out in the direct testimony of Mr. Lon Huber, especially at pages 17 to 33. While there are some details that Mr. Huber leaves for future determination, his proposal includes a customer charge, a bidirectional non-time-differentiated energy service charge, a bidirectional time-of-use delivery charge, and a charge for exporting energy. The time-of-use delivery charge would include only half the transmission charge, with the other half collected through a non-bypassable charge, and would exclude entirely the charges for

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[22] The analysis of market energy prices is complicated by the recent spikes in winter prices, due to tight gas transportation capacity. It is not clear how long those delivery constraints will persist.

[23] Dr. Overcast points out the failure of non-time-differentiated rates to encourage optimal solar orientation (Overcast Direct at 21), but his proposed delivery rate design also does not provide those incentives.

stranded costs, system benefits, external delivery, storm recovery, and the electricity consumption tax.

Mr. Huber proposes that, in addition to not receiving any credit for the non-bypassable components, net metering customers would pay the non-bypassable charges on the portion of the energy they receive directly from their generation.

Q: What portions of this proposal would require adjustment to reflect cost causation?

A: The treatment of the external delivery charge should be corrected, the TOU periods need to be adjusted to reflect the times that contribute to costs, the transmission charge should be treated as entirely bypassable, the charge for exporting energy should be eliminated, and the Commission should reject the proposal to charge customers for power that they supply themselves.

Q: Should the Unitil external delivery charge be treated as not being avoidable by net-metered energy?

A: No. The external delivery charge is simply Unitil's name for the rate component that Eversource and Liberty call a transmission charge.

> The regional transmission and operating component of the EDC consists of all charges from ISO-NE and primarily consists of Regional Network Service (RNS) taken pursuant to the ISO-NE Tariff. Other included costs billed by ISO-NE to Unitil include ancillary services allocated to transmission customers such as voltage control and reactive supply service support, dispatch service, and black-start capability. (NH PUC Order No. 25,928 at 4.)

Most of these cost components are based on monthly peak loads or other load measures. Even Mr. Huber recognizes that some of the transmission charges are avoidable.

Q: How did Mr. Huber choose the peak period of 2 PM to 8 PM, on all days and in all twelve months?

A: He examined the hours in which each utility's load was within 5% of the utility's annual peak. He found that these near-peaks occurred entirely in July to September, and primarily in the hours from 1 PM to 6 PM, with less frequent occurrences in the hours from noon to 1 PM and 6 PM to 7 PM. (Huber Direct at 20–21). Mr. Huber appears to have incorrectly assumed that the costs to the utilities and their customers are determined by each utility's high-load hours, rather than contribution to the peak loads of New England, the so-called local networks, and particular pieces of distribution equipment.[24] To be consistent with his understanding of cost causation, Mr. Huber should have declared the peak period to be July to September, from 1 PM to 6 PM, or perhaps noon to 8 PM.

Based on a general belief that "peak demand in the winter…is also a major concern for New Hampshire and other New England states" (Huber Direct at 21), Mr. Huber looked at Eversource's loads within 5% of monthly (not seasonal) peaks, and declared that nearly all of those hours fell between 4 PM and 8 PM (ibid.).[25] Without explicitly stating any purpose for including the winter months or for using the same hours and prices in the various seasons,

[24] Mr. Huber is clear that his TOU charges are "intended to recover a significant portion of the transmission and distribution equipment costs" but that the periods are not intended to reflect the hours of maximum load on T&D equipment: "the peak and off-peak aspect is linked to New Hampshire utilities' peak load, rather than any particular piece of transmission and distribution equipment." (CLF-OCA 1-22.)

[25] It is not clear what hours Mr. Huber would have identified for the summer if he used the monthly peaks, rather than the annual peaks in the summer analysis.

or providing any rationale for his selection of peak hours, Mr. Huber chose the period 2 PM to 8 PM all year round.

Even supposing that Mr. Huber's reliance on the utility peak and near-peak loads and his inconsistent methods between seasons were appropriate, his selection of peak hours would be incorrect for both the summer (excluding the period from noon to 2 PM, while including the hours from 6 PM to 8 PM) and the winter (including the irrelevant period from 2 PM to 4 PM).

Q: How should the TOU periods be adjusted to reflect the times that contribute to costs?

A: Mr. Huber's proposal does not reflect any TOU treatment to reflect the relative costs of energy supply by time of use, the very large benefit of solar in reducing New Hampshire's allocation of regional generation capacity requirements, the contribution of solar generation to reducing the allocation of transmission costs, or the effect of solar generation on peaks loads of distribution equipment. Mr. Huber's proposals to use the 2 PM to 8 PM peak period and not vary either the period or the pricing by season are inconsistent with the following costing realities:

- generation capacity allocation is determined entirely by contribution to the regional peak load in the summer,
- transmission peaks occur at different times in the summer than the winter,
- 70% of Eversource distribution substation capacity peaks in July through September in hours with high solar output,
- 20% of Eversource distribution substation capacity peaks and 44% of Liberty's feeders with peak-time data occur earlier than 2 PM, outside of Mr. Huber's peak hours.

Q: Please describe the problem with the treatment of transmission costs in the OCA proposal.

A: Mr. Huber proposes that about 49% of T&D costs be recovered from a TOU energy charge levied from 2 pm to 8 pm, every day. (Huber Direct at 28.) He also proposes that half of the utility's retail transmission charge be non-bypassable, because:

> Most…wholesale [transmission] costs are assessed to each utility by ISO New England based on their monthly peak load. Over the course of a year, DG customers are likely to produce energy during times that can reduce their contribution the utility's monthly peak loads but not eliminate it entirely for all months of the year. …
>
> Based on our analysis we propose that the non-bypassable portion should be approximately 50 percent of current retail transmission rates (~1 ¢/kWh). (Huber Direct at 23–24.)

Q: How much of the solar output would be credited with reducing transmission allocations, in Mr. Huber's proposal?

A: The sample of New Hampshire solar facilities produced an average of about a third of their annual output in hours ending 3 PM to 8 PM. Thus, Mr. Huber would credit the net-metering customers for transmission for about one sixth of its output (½ in the energy charge × ⅓ in the designated peak hours).

Q: Is that a reasonable estimate of the relative contribution of solar energy to reducing residential transmission costs?

A: No. As I explain in Section II.C, solar output at the times of the NU local network monthly peaks averaged about 91% of average annual output. Residential load at the NU local network monthly peaks in 2014 (as provided in TASC-Eversource 3-8) averaged 1.48 times the average residential load. In other words, a kWh of solar output displaces the transmission costs of about 0.62 kWh of residential load. Mr. Huber's selection of peak hours and his redundant proposal to exclude half the transmission charges results in a transmission credit for solar that is only about a quarter of the actual value.

Q: How could this problem be corrected within Mr. Huber's general approach?

A: Two corrections would be needed. First, the treatment of half of the transmission charge as non-bypassable would need to be eliminated. Second, the on-peak period would need to be adjusted to include more of the high-solar hours. Using Mr. Huber's preferred (but not cost-based) structure of a single on-peak period on all days for all months, the solar contribution to reducing transmission costs could be recognized by starting the peak period at noon, so about 62% of the annual solar output would be credited with the residential transmission rate, and the transmission compensation to net metered customers for solar output would be about equal to the transmission benefit of solar.

Q: Does the same problem arise for distribution?

A: Yes. As I discuss above with respect to transmission, Mr. Huber would treat only about a third of the solar output as avoiding distribution costs. Averaged over the peak hours of the Eversource substations, solar output was 110% of average; over the peak hours of the Liberty feeders, solar output was 260% of average. While I do not have enough data to compute the appropriate values, either the peak period needs to be expanded or the peak delivery price must be significantly increased to reflect costs.

Q: What costs does the export of energy from net metering customers impose on the system?

A: At current and near-term projected solar penetrations, the cost of exports is very small. It is my understanding that net metering customers pay for any incremental costs of interconnection, such as safety-related switching. I have proposed decreases in the export price to be triggered as distributed generation on a circuit starts to cause backflow of power on the system.

Q: What costs does Mr. Huber believe are imposed on the utilities by exports from net-metered generation?

A: I do not believe that he has identified any such costs. When asked to list each the costs that are "imposed on the utility system by the export of energy by a distributed-generation customer [and] the load conditions under which…exports impose each category of costs," OCA replied that the request was "unduly burdensome" (CLF-OCA 1-29). In the response to TASC-OCA 1-9, Mr. Huber refers to his workpaper LH9 as the source for his computation of export costs. However, workpaper LH9 does not demonstrate (or even argue) that any costs are caused by exports, but simply computes the export charge that would collect 45% of a 4¢/kWh distribution charge, assuming that 50% of the relevant energy is exported.[26] Mr. Huber does not explain what the 50% value is intended to represent.[27]

Q: Do you see any merit in Mr. Huber's computation of the export charge?

A: No.

Q: Should net metering customers be assessed certain charges on energy that they self-supply from their own generation?

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[26] This 45% is based on Unitil's estimate of the marginal costs of line transformers, the "secondary system" and some general plant and overheads, as a fraction of Unitil's estimate of total marginal distribution costs.

[27] Mr. Huber may mean that exports would be half the energy generated by the solar facility, or half the energy consumed by the customer. In any case, Mr. Huber has not explained why the non-exported energy is relevant to setting the export charge.

A: No. If the Commission chooses to use Mr. Huber's proposal as the starting point for designing a new rate for net metering, it should require that the net metering customers be charged for power they take from the system, and paid for power they deliver to the system. The extent to which system costs are reduced by distributed solar generation can be reflected in the selection of the TOU periods, the price differentials among the periods, and the exclusion of some tariff components (systems benefit charge, stranded costs, and consumption tax) from the price paid for energy delivered to the system. A customer who reduces or shifts usage of utility services, whether by installing a ground-source heat pump, installing a solar water-heating system, changing work schedules, moving to Florida in the winter, or installing photovoltaic panels, should not be charged for the energy not taken from the utility. Applying special charges to customers with solar photovoltaic, and not to other customers who reduce their usage, would be unduly discriminatory.[28] The OCA declined to respond to a question about whether load reductions from energy-efficiency investments should be treated differently from its proposal for distributed generation (CLF-OCA 1-7).

Q: How might the approach proposed by Mr. Huber be adapted to be useful in New Hampshire?

A: If the Commission is interested in Mr. Huber's proposed TOU rate, as the default for all residential customers or an alternative rate design, it should instruct the Staff to convene a stakeholder process to revise the TOU periods

[28] Utilities generally impose special charges based for equipment behind the customer's meter when that equipment creates surges in load or power-quality problems for other customers, such as the inrush current and "intermittent flow of large currents" from large flashing sign, arc welders and the like described in Sections 8 and 10 of Liberty's Specifications for Electrical Installations (CLF-Liberty 1-10).

and timing to reflect the effects of summer midday loads on capacity obligations and prices, as well as the effects of various times and seasons on generation energy prices and costs (including supplier wholesale costs and RPS compliance), transmission allocation, marginal transmission costs, and substation and feeder costs (and line transformers, if their loading pattern is available). That process should also compare the total value of solar to the compensation that customers with net-metered solar facilities would receive. Mr. Huber volunteers that his proposal "does not include several categories of potential societal benefits that are difficult to quantify such as avoided air emissions, avoided fuel price uncertainty, benefits to the local economy, etc." (Huber Direct p. 8, lines 19–21.)

IV. Pilots

Q: What pilot programs are appropriate for the Commission to initiate in the near term?

A: As I discussed in my direct testimony, a locational net metering pilot, targeted at an area with an impending shortage of delivery capacity, would be useful. In addition, the City of Lebanon has expressed interest in developing a real-time pricing pilot for distributed generation and other customers (Direct Testimony of Clifton Below) and the OCA has proposed a time-of-use rate for distributed generation customers (Direct Testimony of Lon Huber). Both of those options require additional development, as Mr. Below readily acknowledges in his direct testimony and as I discuss in Section III.C with regard to Mr. Huber's proposal.

Q: How do you recommend that the Commission proceed with respect to the pricing pilots?

A: I recommend that the Staff convene a stakeholder process to attempt to:

- Develop useable data on distribution peaks for all the utilities, the transmission peaks for Liberty, avoided costs, price-suppression effects, and other information missing from the record in this proceeding.
- Determine appropriate pricing periods and price differentials for the energy rates in the TOU pilot and for the non-LMP portion of the real-time-pricing pilot.
- Determine the metering arrangements and establish that the costs of the metering appear to be reasonable, considering the potential benefits.
- Define the process for selecting participants and the control group.
- Outline the evaluation process and the selection of an evaluation consultant, if required.

V. Decoupling and Cost Recovery

Q: What mechanisms have been proposed in this proceeding to protect the utilities from lost revenues, due to distributed generation?

A: The OCA has proposed that net metering installations (and perhaps all distributed generation) be required to pay for additional metering, so that the utility can be compensated for the revenue reduction from the generation behind the meter. (Huber Direct at 30.)

Q: Is this an appropriate solution to the issue of lost utility revenue?

A: No. Utilities do not impose similar metering costs for customers who reduce their energy usage in other ways, such as investing in energy efficiency. There is no need to separately compute the revenue effect of distributed generation, as opposed to energy efficiency, price response, and customer incomes and spending patterns, because there is a superior alternative. I understand that, in connection with the Energy Efficiency Resource Standard (EERS), each utility is required to apply for revenue decoupling or equivalent in its first rate case after 2020; if any utility files a rate case prior to 2020, the Commission should implement decoupling at that time.

Q: What do you mean by revenue decoupling?

A: Traditional ratemaking ends with the setting of fixed rates that the utility will charge per customer-month, kWh sold, and kW of demand billed; the revenue collected by the utility depends on the number of customers, kWh and kW it bills.[29] Revenue decoupling sets rates for an initial period (such as a year), but also sets a revenue target, which may be entirely fixed (in millions of dollars per year) or partially variable, such as including the costs of capital additions for connecting new customers not included in the original revenue target. If revenues are higher than the target, they are credited back to the customers; if revenues are lower than the target, the utility collects the difference. These adjustments generally flow through a reconciling rider.

Revenue decoupling protects the utility from declining sales due to any cause (including energy-efficiency programs, energy efficiency due to efficiency standards and other non-program drivers, mild weather, changing consumer lifestyles, as well as distributed generation) and protects the customers from higher total bills in extreme weather. Revenue decoupling avoids the need for expensive metering of distributed generation and detailed estimates of the sales and revenue effects of energy-efficiency programs.[30]

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[29] In New Hampshire, this process applies only to distribution rates, with all other rate components subject to periodic adjustment and reconciliation.

[30] Some monitoring and evaluation of energy-efficiency programs is still required, to assist in program screening and long-term resource planning, but the precision of the required estimates

VI. Recommendations

Q: Please summarize your conclusions and recommendations.

A: The utilities have not seriously engaged with quantifying the benefits of distributed solar generation, including the contribution of behind-the-meter solar generation (whether used by the host customer or exported to the distribution system) to reducing utility allocations of generation and transmission costs, reducing transmission and distribution investments, and reducing generation prices. As a result, their estimates of the costs and benefits of net metering are not useful to the Commission.

Based on the available evidence of the benefits of distributed generation, the current net metering compensation calculation should be altered incrementally, with the credit for exported energy reduced by certain specific universal charges, but not eliminated. I recommend that new alternative net metering tariff should consist of the following:

- Each net-metering customer should pay the same rate as other customers in its rate class for energy taken from the utility.
- Net-metering customers on feeders with low distributed generation penetration should be credited for monthly net energy delivery to the system at the sum of the applicable transmission and distribution rates and the utility's default generation (or energy service) rate. The compensation should not include the charges for stranded costs, system benefits (i.e., low-income discounts and energy-efficiency programs), or the energy consumption tax.

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can be much lower (and the evaluation much less expensive) than for the revenue-grade estimates necessary to reliably determine lost revenues.

- If distributed generation on a feeder rises to significant levels, and the benefits of that distributed generation consequently begin to diminish, the compensation for net metering output should decline. As I proposed in my direct testimony, this should start with a 1¢/kWh reduction for projects added after the maximum backflow of power on a feeder (distributed-generation output minus load on the feeder) exceeds 50% of the feeder capacity, with another 1¢/kWh decline when backflow reaches 60% of capacity and each further 10% increase. Those credit reductions should not apply to customers who can curtail output to the distribution system at low-load conditions.

Given the utilities' failure to meaningfully engage in quantifying the benefits of net metering to the utilities and the other customers, the Commission should also direct that Staff convene a stakeholder process to design the net metering pilot programs and improve the estimates of the benefits of distributed generation, as well as the costs of adapting the distribution system to accommodate higher cumulative levels of distributed generation. This stakeholder process may dovetail well with ongoing grid modernization efforts in the state.

As the penetration of net-metered capacity rises, several factors relevant to distributed generation rates may change: peak hours may shift later in the evening (and in some months and on some distribution equipment, earlier in the morning), loads on transmission and distribution equipment may fall, the costs avoided by distributed generation may decline, backflow on the distribution system may require some capital additions, and over- or under-estimates that are trivial at low penetrations may become more significant as penetration rises, in addition to all the changes in price structure that may change over time. Therefore, I recommend that the penetration of net-metered capacity reaching 5% of the combined load of the three utilities trigger a requirement for Staff to convene a stakeholder process to consider whether additional changes are required to net metering and related regulations or rate mechanisms. The Commission should also commit to initiating a proceeding to consider changes in distributed-generation compensation if distributed-generation capacity reaches 10% of utility capacity prior to the report from the stakeholder process, to ensure that the reality does not drift too far from the assumptions of the rate design ordered in this proceeding.

Q: Does this conclude your reply testimony?

A: Yes.