STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

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

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

CONSERVATION LAW FOUNDATION

Resource Insight, Inc.

OCTOBER 24, 2016

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I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-four states and six Canadian provinces, and two US Federal agencies. This testimony has included many reviews of utility avoided costs, marginal costs, rate design, and related issues.

Q: Have you testified previously before the New Hampshire Public Utilities Commission?

A: Yes. I have testified three times before the Commission:

- PSC DE 81-312, the Public Service of New Hampshire (PSNH) supply and demand proceeding, on conservation program design, ratemaking, and effectiveness, and the cost of power from Seabrook, October 1982.
- PSC 84-200, Seabrook Unit-1 investigation, November 1984.
- PUC DR 96-150, PSNH stranded costs, December 1996.

My testimony in the first case was sponsored by Conservation Law Foundation. In the other two cases, I testified on behalf of the Office of Consumer Advocate, for whom I also prepared comments on restructuring New Hampshire's Electric-Utility Industry (with Bruce Biewald and Jonathan Wallach) in 1996.

Q: What experience do you have in evaluating the costs and benefits of distributed resources?

A: I have worked on numerous projects concerning the determination of rates for customers with behind-the-meter generation and for non-utility power suppliers, including the valuation of distributed resources, since the early 1980s, as listed in Exhibit PLC-1. Among other things, I was a member of the team that estimated the New England-wide avoided costs for energy-efficiency programs in 1999, 2003, 2007, 2019, 2011, and 2013.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Conservation Law Foundation.

Q: What is the scope of your testimony?

A: I will address most of the topics that the Commission is directed to consider by HB 1116, regarding customers with distributed generation, variously called “customer-generators” or “behind-the-meter generation.” The principal focus in this proceeding is on net metering, in which customers are credited for energy delivered to the utility at the retail rate they pay for consumption.

While I concentrate on distribution photovoltaic solar installations, similar considerations apply to other renewable resources and combined heat and power applications.

Q: Please summarize your responses to the topics laid out in HB 1116.

A: The following is a list of those topics, with a brief summary of my responses:

- **Costs and benefits of customer-generator facilities**. The broadest possible range of costs and benefits should be considered in determining the ratemaking for distributed generation. I enumerate and describe many of these below.
- **Avoidance of unjust and unreasonable cost-shifting**. The energy flowing back into the distribution system has essentially the same effect

on utility costs as reduction in customer loads. Customers should receive the same incentives and compensation to providing renewable energy to the system that they receive for reducing their loads.

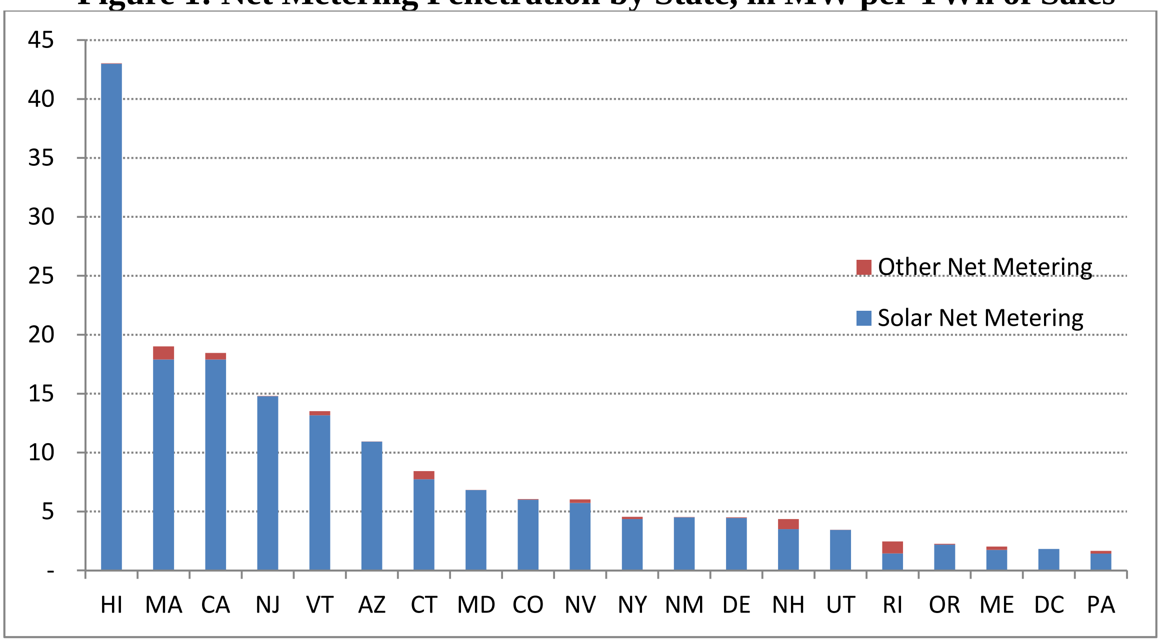
- **Rate effects on all customers**. The rate effects of net metering are unlikely to be significant at the low penetrations of net metering experienced in New Hampshire. Whether the net effect of net metering is to reduce costs for other customers is not yet clear.
- **Alternative rate structures, including time-based tariffs**. The Commission should explore time-varying rates, through pilot programs and optional tariffs, with the long-term goal of replacing demand charges with time-varying energy rates.
- **The size of facilities eligible to receive net metering tariffs**. Distributed renewable generation installations that are smaller than or comparable to the host facility, and do not require expanded interconnections, should be eligible for net metering. In addition, the Commission should consider options for facilitating community solar, to allow renters, consumers without suitable roof configurations, and lower-income customers to participate in distributed solar development.
- **Timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism**. The Commission should invite the utilities to propose comprehensive revenue decoupling, so that behind-the-meter generation, energy efficiency, time-varying rates and other improvements in the usage of energy do not burden the utilities excessively.

A. Net Metering in New Hampshire

Q: Please describe the extent of net metering in New Hampshire.

A: New Hampshire has modest levels of net metered load. Figure 1 shows data on the twenty states with the highest penetration of net-metered distributed generation, measured in megawatts of capacity per terawatt-hour (TWh, or million megawatt hours) of sales. The net-metering capacity is from the Energy Information Administration's (EIA's) Form 826 database, as of July 2016, and the sales are 2015 annual values, also from the EIA Form 826. This comparison does not take into account the differences in energy output per MW of capacity; a megawatt of rooftop photovoltaic will produce significantly more energy in Hawaii, California, Arizona, Colorado, New Mexico, or Utah than in New Hampshire.

Figure 1: Net Metering Penetration by State, in MW per TWh of Sales



Based on these EIA data, Hawaii has by far the highest net-metering penetration, at almost 10 times New Hampshire's, while Massachusetts and California have almost four times New Hampshire's net-metering density, and New Jersey and Vermont have over three times New Hampshire's. New

Hampshire comes in 14th nationwide in capacity per unit retail sales, and probably 15th in energy after Utah.

Q: What does this comparison indicate about the relative urgency of fine-tuning New Hampshire's approach to net metering?

A: New Hampshire has much less net-metered generation than the leading states. Hawaii has so much solar net-metered generation (about 25% of peak load) that reverse flows occur on parts of the distribution system; the Hawaii Public Utilities Commission has reduced the rate for power exported to the distribution system from the retail rate to the still-high wholesale prices (15¢/kWh to 28¢/kWh, depending on the island) and implemented minimum bills. Several of the other states with the highest net-metering penetrations—including California, Massachusetts, and Vermont—have considered changes in their net-metering arrangements, and have settled on relatively minor changes in billing arrangements.

According to EIA, New Hampshire's net-metered capacity is approximately 48 MW, or 2% of ISO-NE's 2,500 MW weather-normalized 2016 forecast for the state.[1] Vermont reports 135 MW of net-metered capacity as of March 2016, or over 13% of the state's 1,000 MW peak.[2] Net-metered

[1] ISO-NE reported just 26.4 MW of photovoltaic capacity in New Hampshire at year-end 2015 (Final 2016 PV Forecast Details, ISO-NE, May 9, 2016, p. 11), while EIA reported 38.5 MW. The ISO definitions for its forecast may not match the net-metering definition used by EIA.

[2] From "Net Metering Percentages of Utility Peaks," Vermont Department of Public Service, March 9, 2016, http://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/Net_Metering/Net%20metering%20percentages%20of%20utility%20peaks%202016-3-9.xls. This value is about twice what EIA reports for Vermont for 2015, but just 8% higher than ISO-NE reported in the PV Forecast Details.

capacity in Massachusetts is about 8% of the state's peak, while Connecticut is at about 3% or 4%.

New Hampshire has some years before it reaches the net-metering levels at which other New England states have reviewed and largely maintained their net-metering policies. While the Commission would be well-advised to determine the timing of its next review of its policies, experience in other states suggests that there is no obvious rationale for major changes in the near term.

The Commission should avoid premature course changes and adding unnecessary complication to net-metering mechanisms, since those actions could inhibit further penetration of distributed generation.[3] Any near-term complications in the regulation of distributed generation will likely need to be revisited and revised as the information available to the Commission improves and its policy options (such as developments in grid modernization) increase. Minimizing the number of major course changes provides stability for all parties: the distributed-generation industry, customers, regulators and the utilities.

B. Framework for Evaluating Rates for Distributed Generation

Q: How should the Commission approach the question of setting rates for distributed generation?

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[3] See Draft NARUC Manual on Distributed Energy Resources Compensation, Staff Subcommittee on Rate Design, 2016, p. 62 ("For the jurisdictions with low DER penetration and growth, there is time to plan and take appropriate steps and avoid unnecessary policy reforms… Reforms that are rushed and not well thought out could set policies and implement rate design mechanisms that have unintended consequences such as potentially discouraging customers from investing in DER resources…")

A: The Commission should review ratemaking options in terms of the following main criteria:

- Recognition of all system costs and benefits.
- Simplicity and consumer understanding.
- Effectiveness of rate design in encouraging efficient consumer choices.

III. Costs Avoided by Distributed Solar

Q: What are benefits of distributed solar energy?

A: The benefits of distributed solar energy include the following:

- Avoided generation energy costs.
- Avoided generation capacity costs.[4]
- Reduced transmission and distribution line losses.
- Avoided load-related transmission upgrades.
- Avoided load-related distribution upgrades.
- Reduced wear and tear on transmission and distribution equipment.
- Reduced emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), oxides of nitrogen (NOx), air toxics, and fine particulates.
- Reduced effects of power generation on water consumption and water quality.
- Reduced market prices for natural gas, electric energy and capacity prices.
- Reduced sensitivity of power-supply costs to fuel prices and market conditions.
- Reduced cost of environmental compliance.

[4] There are also several categories of ISO-NE charges for ancillary services and fees that New Hampshire may avoid due to lower zonal load resulting from distributed generation.

- Local employment and economic stimulus.

In addition, distributed solar generation (particularly with storage) can be an important component of local microgrids and other arrangements to allow customers to ride through disruptions of the utility delivery system.

While it is more difficult to quantify than the system benefits, there also may be significant social value for customer choice and local control of resources.

Q: Are all of these benefits captured by the customers with distributed generation?

A: No. The solar customers reduce their bills, which would include some approximation of the generation energy and capacity costs, and of average line losses and embedded transmission and distribution (T&D) costs. Since photovoltaics provide more energy in on-peak than in off-peak hours, particularly in the summer, the solar generation (whether it reduces the customer's load or feeds back into the distribution system to serve other nearby customers) will tend to reduce average costs, benefiting other customers.

Customers as a whole (across the utility, all of New Hampshire, or the region) benefit from the avoided T&D upgrades, reduced wear and tear, the reduction in percentage line losses, reduced market prices, reduced environmental effects, and reduced cost of environmental compliance.

Q: When do the peak loads occur on the generation, transmission and distribution systems?

A: The generation capacity charges for New Hampshire customers are determined by the zonal load coincident with the ISO-NE annual peak. Table 1 summarizes the ISO-NE peak hours over the past 16 years. The peak load occurs most often in the hour from 2 PM TO 3 PM, when the solar equipment would be generating, especially on the sunny days that tend to drive summer peaks.

Table 1: Times of ISO-NE Annual Peaks

Year	Month	Date	Day Type	Actual Peak	Hour Ending
2000	June	27	Tue	22,005	13
2001	August	9	Thu	25,072	15
2002	August	14	Wed	25,422	15
2003	August	22	Fri	24,685	15
2004	August	30	Mon	24,116	15
2005	July	27	Wed	26,885	15
2006	August	2	Wed	28,130	15
2007	August	3	Fri	26,145	15
2008	June	10	Tue	26,111	17
2009	August	18	Tue	25,100	15
2010	July	6	Tue	27,102	15
2011	July	22	Fri	27,707	15
2012	July	17	Tue	25,880	17
2013	July	19	Fri	27,379	17
2014	July	2	Wed	24,443	15
2015	July	20	Mon	24,437	17

The allocation of transmission costs is based on monthly zonal peaks, rather than the ISO-NE system peak. Table 2 provides the monthly peak hours for the New Hampshire zone, from ISO-NE data for March 2003 to December 2015. Most of the monthly zonal peaks from May to September are in daylight hours, when solar would reduce loads, while the peaks in the other months largely occur after dark.

Table 2: New Hampshire Zonal Peaks, by Hour Ending and Month

	Month											
HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
13	-	-	-	-	1	2	-	-	-	-	-	-
14	-	-	-	-	4	1	2	2	1	-	-	-
15	-	-	-	1	-	3	7	5	-	-	-	-
16	-	-	-	-	3	3	2	2	3	-	-	-
17	-	-	-	-	4	2	-	4	4	-	-	-
18	4	1	-	-	-	2	2	-	-	2	13	11
19	8	11	13	1	1	-	-	-	-	10	-	2
20	-	-	-	8	-	-	-	-	5	1	-	-
21	-	-	-	3	-	-	-	-	-	-	-	-

Distribution equipment peaks at a variety of hours. Eversource's response to Staff 1-025 shows that about 40% of its 2015 distribution substation peaks (in megawatts) occurred from 10 AM to 2 PM, or noon to 4 PM in the summer, and another 40% occurred in 5 PM to 7 PM in July–September, when solar output would be small but the substation transformers would have been cooler due to the contribution of distributed generation to reducing loads in the afternoon.

Table 3: Eversource 2015 Distribution Substation Peaks, by month and hour (MW)

	Month											
HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
9	-	-	-	-	-	-	-	-	-	-	42	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	29	-	36	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	62	28	-	-
13	-	-	-	-	-	-	-	-	18	-	-	-
14	-	122	-	-	-	-	-	-	-	-	100	-
15	-	-	-	-	-	-	38	39	-	-	28	-
16	-	-	-	-	-	-	47	202	150	-	-	-
17	-	-	-	-	-	-	138	55	227	-	-	-
18	-	-	-	-	54	-	120	69	-	-	67	-
19	53	55	17	-	-	-	122	102	-	-	-	36
20	-	-	-	-	-	-	-	-	-	-	27	23
21	-	-	-	-	-	-	15	-	77	-	-	-
22	-	-	-	-	-	-	-	-	34	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	6	-	-	-	-

Solar net metering installations will thus contribute to reducing the need for upgrading and adding substations. The same pattern is likely to apply to feeders.

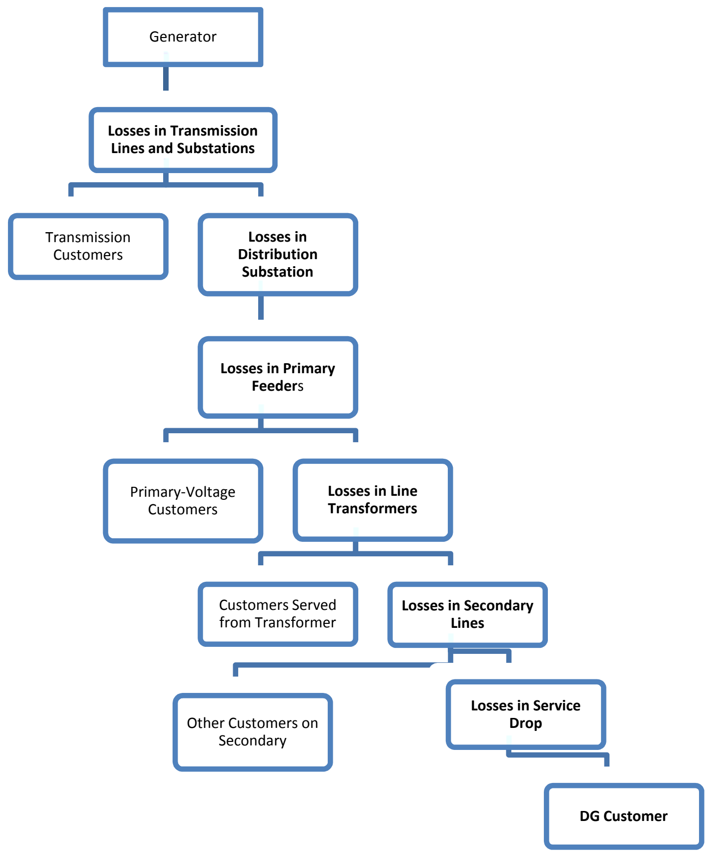
Q: Does solar net-metering generation reduce the regional need for generation capacity?

A: Yes. ISO-NE reflects behind-the-meter solar generation in its load forecasts, which determine the amount of capacity acquired in the forward capacity auctions.

Q: How do distributed generation resources reduce line losses in the transmission and distribution systems?

A: The losses in conductors (including transmission and distribution lines and in transformers) varies with the square of the power flowing through the wire, so a 1% reduction in load reduces losses by about 2%. The levels of conductor losses from the generators to a distributed generation customer at secondary voltage (such as a residential customer) are illustrated in Figure 2.

Figure 2: Line-Loss Schematic



Reducing the DG customer's load reduces the losses in the service drop from the street to the customer, the secondary line (if any) serving that customer, the line transformers, the distribution feeder, the distribution substation, and probably several transmission lines and transmission substations. Rates are generally designed to collect average line losses from customers, so any reduction in line losses above the average level flows to all customers. For example, the average energy line-loss value included in the allocation of ISO-NE locational marginal costs to customers in the New Hampshire zone would tend to decline with the addition of distributed generation. The same is true for the average peak-hour line loss factor embedded in the New Hampshire zonal load for the assignment of generation capacity responsibility.

Q: Would the same benefit occur for energy from distributed generation that flows back into the distribution system?

A: Yes, for the most part. So long as distributed generation is less than twice the customer's load, the excess energy flowing through the service drop will be less than if the customer had no generation. At some times, the distributed generation may be more than twice customer load, so losses in the service drop will likely be higher in some moments with the distributed generation than without.[5] Whether losses in the service drop rise or fall due to surplus energy depends on the size of the solar array and the customer's load shape. In any case, the service drop accounts for a minor portion of total losses.

As power flows higher up the delivery system, the moments in which distributed generation can increase losses become rarer. If the line transformer serves six customers, load running through the transformer (and hence its wire losses) will be lower unless the distributed generation output is twice the consumption of all six customers. At the feeder level, there are typically hundreds of customers; even if several of them have solar panels, they are unlikely to generate more than those hundreds of customers are using. And at the substation and transmission levels, the chances of increased load flows

[5] For example, 5 kW array could be operating near peak capacity on a mild June midday, with no cooling load, and when no one happens to be home. At some points, the refrigerator will happen to cycle off, leaving only a hundred watts or so of base loads, such as the set-top cable box, the wifi router, standby mode on televisions and computers, and various transformers and chargers. This combination of circumstances may be relatively rare, but will occur. Since the capacity of the service drop will generally be much larger than the capacity of the solar array, exporting 4 kW from the house, rather than importing the small base load, will impose no costs other than the line losses.

become vanishingly small until penetration of distributed generation rises far above the levels in New Hampshire.

Q: Are the benefits of group net-metering solar comparable to the benefits of behind-the-meter distributed generation?

A: Group net-metering solar would generally provide the same benefits as behind-the-meter generation, in terms of environmental benefits; generation, transmission, and most distribution costs; and most line losses. It also has the benefit of making distributed generation investments available to populations who otherwise might be excluded due to space or financial limitations, and enables communities to use common resources (such as municipal land and social infrastructure) to pursue common goals.

Depending on the configuration of the group net-metering solar project, including its size and location, the benefits may be slightly smaller than for behind-the-meter generation serving only the host. A group net-metering project may more frequently result in large net power flows toward the distribution system, modestly reducing the benefits of net metering compared to a project sized only for the host. But the low ceiling on the capacity of each group net-metering project (100 kW) would limit this effect.

Higher size limits, credit adders or other incentives might be appropriate for community solar projects that serve targeted groups, such as lower-income households, or that achieve other goals, such as rehabilitation of brownfield sites.

Q: How does distributed generation, particularly solar, extend the life of transmission and distribution equipment?

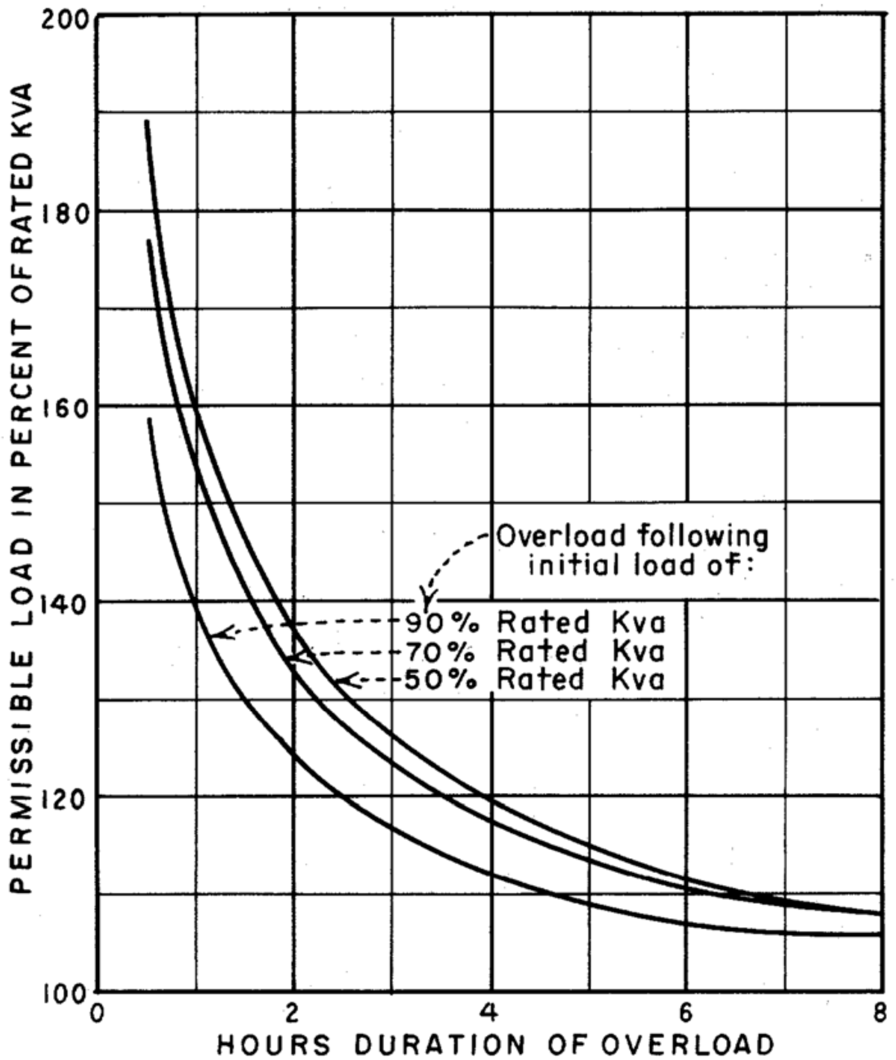
A: Existing transmission and distribution equipment wears out faster if it is more heavily loaded. The capacities of transformers and underground power lines, in particular are limited by the build-up of heat created by electric energy losses in the equipment. Every time a transformer approaches or exceeds its rated capacity (a common occurrence, since transformers can typically operate above their rated capacity for short periods of time), its internal insulation deteriorates and it loses a portion of its useful life. Long hours of high loads result in heat building up in lines (especially underground lines) and transformers, increasing the damage of peak loadings.

Figure 3 illustrates the effect of the length of the peak load, and the load in preceding hours, on the load that a transformer can carry without losing operating life.[6] The initial load in Figure 3 is defined as the maximum of the average load in the preceding two hours or 24 hours. A transformer that was loaded to 50% of its rating in the afternoon can endure an overload of 190% for 30 minutes or 160% for an hour. If the afternoon load was 90% of the transformer rating, it could only carry 160% of its rated load for 30 minutes or 140% for an hour.[7]

[6] The figure is from Permissible Loading of Oil-Immersed Transformers and Regulators, United States Department of the Interior, Bureau of Reclamation, Facilities Engineering Branch, Denver Office, April 1991. This specific example is for self-cooled and water-cooled transformers designed for a 55°C temperature rise; other designs show similar patterns.

[7] Utilities recognize that the length of overloads is critical to determining whether a transformer needs to be replaced. For example, Pepco and Delmarva Power have established standards for replacing line transformers when the estimated average load over a five-hour period exceeds 160% of the rating of overhead transformers or 100% for padmount transformers. They have not found it necessary to establish comparable policies for shorter periods.

Figure 3: Permissible Overload for Varying Periods



Similarly, if the transformer's high-load period is currently eight hours in the afternoon and evening, and the preceding load is 50% of rated capacity, solar generation that cuts the high-load period to three hours would increase the permissible load from about 108% of rated capacity to about 127%. Under these circumstance, the transformer can meet higher load without replacement or addition of new transformers.

Alternatively, if the transformer is loaded heavily enough that the useful life is reduced, reducing the pre-overload power flow and shortening the overload period would mitigate that reduction, extending the life of the equipment and reducing the rate of failure. This is particularly relevant for line transformers, for which the utility will not usually be able to closely monitor transformer loading and temperature.

Q: Do the same issues apply to overhead lines?

A: Yes, although the mechanisms are different than for the underground lines and transformers. The capacity of overhead lines is often limited by the sagging caused by thermal expansion of the conductors, which also occurs more readily with summer peak conditions of high air temperatures, light winds and strong sunlight. Overheating and sagging also reduce the operating life of the conductors.

Q: Do those benefits flow to all utility customers?

A: Yes. The reduction in replacement transmission investments over time would reduce transmission rates to all customers. The reduced replacement investments in distribution would reduce rates for customers served at distribution voltages.

Q: Does distributed solar generation reduce pollution emissions from the electricity sector?

A: Yes. Distributed solar generation reduces the fuel burned in power plants and hence the following emissions:

- carbon dioxide from burning coal, oil and gas;
- sulfur dioxide from burning coal and oil plants;
- NOx from burning coal, wood, oil and gas;
- Fine particulates from burning coal, wood, and oil;[8] and

[8] In addition, some of the sulfur dioxide and NOx form fine particulates in the atmosphere, after they are emitted from the plant stack.

- Toxic chemicals (such as mercury, heavy metals, chlorine and reactive hydrocarbons) from burning coal, wood, and oil.

New Hampshire's generation plants include the Merrimack and Schiller 4 and 6 coal plants; the Newington steam plant, which burns gas in most of the year and heavy oil in some winter periods; and the Schiller 5 wood-fired plant; the Newington and Granite Ridge combined-cycle gas plants (which may burn oil in periods of winter gas shortages). New Hampshire residents benefit from reductions in emissions at power plants in New Hampshire and in neighboring states, such as Massachusetts and New York.

While these emission reductions benefit all New Hampshire residents, they may be particularly important for low-income communities, who tend to bear higher pollutant loads and who may be more vulnerable to climate change. Low-income households are likely to be more affected than wealthier households by heat waves, increased snowfall, flooding from heavy rain, and (in rural areas) drought.

Q: How does distributed generation reduce the cost of compliance with environmental constraints?

A: For any future statewide or regional cap on emissions (most likely for carbon, although it could also be applied to NOx), lower emissions from electric generation (due to distributed renewables) would make compliance easier and allow for less stringent controls on other end uses, from building heating to transportation.

IV. Costs Imposed by Distributed Solar

Q: What costs are imposed on the utility system by distributed solar generation, such as behind-the-meter generation?

A: While very few system costs are imposed by behind-the-meter generation, some utility interests have suggested the opposite. A recent example of this position appeared in the October 2016 issue of *Public Utilities Fortnightly:*

> However, the customer still requires a connection to the grid for those hours when the solar panels are not generating all of the electricity required on premises. An example of this is at night, or on cloudy days. The connection is also required to export and sell any excess energy that the customer may produce.
>
> Solar customers benefit from having enough power plants being built to provide adequate backup when the sun is not shining. It is important to note that often the customer's demand for electricity exceeds the capacity of the solar panels. That makes solar energy an intermittent and unpredictable power source. Additionally, its energy production is generally not coincident with peak demand of most utilities in the United States.
>
> The customer still requires a meter, a call center to answer questions about monthly bills, and other vital services. It is only equitable that the solar customer should pay the utility for a share of those services. However, net metering policy prevents this from happening. ("Rethinking Rationale for Net Metering, Quantifying Subsidy from Non-Solar to Solar Customers;" Barbara Alexander, Ashley Brown, and Ahmad Faruqui; *Public Utilities Fortnightly*, Volume 154, No. 10, pp. 28–33)

Q: What is incorrect about this argument?

A: There are at least four problems in this short passage. First, the argument entirely ignores the benefits of the solar energy, both in reducing the customer's load at generally higher-load and higher-cost hours and in feeding power back to the system and reducing power flows. I discuss those benefits in Section III.

Second, there is no additional cost to the utility for the distributed generation grid connection, either for nights and cloudy days or "to export and sell any excess energy."[9] The same grid connection that supplies the customer without distributed generation will supply the customer with distributed generation and will also carry the energy exported to the distribution system.

Third, solar customers do not require additional power plants. Distributed generation either avoids the need for central generation or has no effect; it does not increase capacity requirements. Solar panels are generally producing energy coincident with annual peak demands in New Hampshire and New England.[10] In the hours of New England annual peak loads (the hours ending at 3 or 5 PM in July or August), south-facing solar panels in Manchester would produce about 150% (at 3 PM) to 70% of their average energy output; for western-facing panels, those values rise to 190% at 3 PM and 120% at 5 PM. Solar output is even higher in early hours of the high-load days, which also contribute to the probability of capacity shortfalls, and hence New England's required reserve margin.

Fourth, it is indeed fair that solar customers be charged for the meters and other services required to serve incremental customers. But it is also fair and efficient to reward customers for the services that they provide to other customers, which may exceed the cost of metering and billing.

Q: What costs can distributed generation actually impose on the utility system?

A: At low penetration levels, such as those prevailing in New Hampshire, the costs are very limited. Any solar equipment (or associated storage) that could feed power back into the system during an outage on the distribution system

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[9] Net metering is not usually treated as a sale of energy, in any case.

[10] Solar output may not peak at the same hour as utility, state or regional load, but solar equipment generally operates on summer peak hours.

will need a safety switch to protect line workers who would expect the line to be de-energized.

As distributed generation penetration rises, the flow of power from the distributed generation may confuse some protective devices (such as breakers and reclosers), requiring replacement or reconfiguration of some devices.

Only at very high penetrations would distributed generation cause power flows in the upstream direction (toward the substation) to rise above the downstream power flows (towards customers) that would have otherwise occurred. Some distributed generation resources, such as wind turbines, may generate at peak capacity in deep off-peak hours, when loads on the distribution line may be very low; in contrast, solar generation peaks in the middle of the day, when most distribution feeders will be well above their minimum load.

V. Rate Design for Distributed Generation

A. Rate Design Components

Q: Which rate design components are commonly proposed in response to rising levels of distributed generation?

A: The most common proposals for regulatory action include:

- increasing the fixed monthly customer charges,
- imposing demand charges for residential and small-commercial customers who have not traditionally been assessed those charges,
- exempting some energy charges from the net-metering, and
- implementing time-varying energy rates.

1. Customer Charges

Q: Are increased customer charges an appropriate response to distributed generation?

A: No. Fixed customer charges increase the stability of utility revenues, since customers cannot escape the charges without disconnecting from the utility entirely. But fixed charges provide no useful price signals to consumers. Fixed charges do not encourage energy conservation, or shifting load to lower-cost time periods, or provide any other useful signals. The fixed charge is useful only in giving customers a price signal about the incremental cost of having the utility add a service drop and meter, such as for an auxiliary apartment, backyard workshop or office, rather than the customer paying to connect the auxiliary load through its own meter. For this purpose, the customer charge should be limited to the costs of adding a customer, which would consist of the meter, service drop, meter reading and maintenance, billing, and a contribution to customer service costs. In most cases, adding a customer does not require extension or reinforcement of the distribution system, except for load-related costs, which should be recovered through usage costs.

For existing customers, the rationale for customer charges is even weaker than for the addition of customers. If a higher customer charge succeeded in encouraging a customer to leave the system, the utility would avoid the meter reading and billing expense; it might not even bother recovering the meter and service drop, since it could not avoid the sunk cost of installation and would incur the cost of removal.

High customer charges run the risk of encouraging customers to install additional electrical storage and leave the utility system. If the fixed charge is higher than the utility's savings from losing the customer, the decision to cut the cord may be economically inefficient.

2. Demand Charges

Q: Is imposition of demand charges an appropriate response to distributed generation?

A: No. A demand charge, as that term is generally used in utility practice, imposes a charge based on the customer's highest usage (usually over 15 minutes or one hour) at any time during the month (and in some cases, any time during the year). Demand charges are difficult to avoid and are therefore often grouped with customer charges in the category of "fixed charges," as opposed to the variable energy charges that customers can control.

Some utilities (and sometimes other parties) get confused by terminology, and assume that any cost classified as "demand-related" in an embedded cost-of-service study should be recovered through a demand charge. The demand-related costs are related to system coincident peaks (and other high system loads) or peak loads on various transmission and distribution equipment, and are typically allocated on measures of coincident demands or proxies, such as class diversified peak loads.

A similar confusion arises in the conflation of two meanings of "fixed costs:"

Fixed Costs 1: costs invariant with respect to load or usage, and thus not avoidable by reducing load.

Fixed Costs 2: costs fixed over the year, not varying in the short run.

Many costs in any particular year are largely determined by the cumulative investment and construction commitments in the past, and are hence fixed by Definition 2. However, even though transmission and distribution costs are overwhelmingly fixed over the year, none of them are fixed over load, since generation and transmission is added only for load-related reliability and energy savings. Hence, they are not fixed by Definition 1 and should be recovered through rates that vary with usage and encourage customers to reduce and control the usage that contributes to the costs.

Q: Are demand charges helpful in providing pricing signals to ratepayers?

A: No. Demand charges are inappropriate for several reasons, including the following:

- Demand charges do not target peak demand reduction, since they apply to customer maximum demands, not to the times of system peaks or equipment maximum loads. Customer peaks occur at a wide variety of hours, on a wide variety of days, with many far from the coincident peaks on the generation, transmission or distribution systems.
- Demand charges do not provide appropriate incentives to conserve, even during high load hours.
- Not only are demand charges ineffective in shifting loads off high-cost hours, they may cause some customers to shift loads in ways that increase costs. For a customer who experiences its maximum summer demands at noon or 9 pm, a demand charge encourages the shifting of load into the afternoon peaks on the generation, transmission and distribution systems.
- Demand charges are very difficult for customers to understand, let alone mitigate.

Q: Please explain why demand charges do not provide the appropriate incentives.

A: Demand charges are a particularly ineffective means for giving price signals, for the following reasons:

- The demand-charge portion of the electric bill is determined by the customer's individual maximum demand. Capacity costs are driven by coincident loads at the times of the peak loads, not by the non-coincident maximum demands of individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of equipment, especially since the peaks on the secondary system, line transformer, primary tap, feeder, substations, sub-transmission lines, and transmission lines occur at varying times.
- Demand charges provide little or no incentive to control or shift load from those times that are off the customers' peak hours but that are very much on the generation and T&D peak hours. Customers can avoid demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system, on the New Hampshire transmission peak, or on the ISO-NE peak-load hour. This will cause customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, and/or the regional generation system.
- Demand charges are difficult to avoid; even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour. This attribute of demand charges erodes the incentive to even try to avoid the charge, since weeks of careful effort can be swept away if the electric water and refrigerator happen to go on simultaneously. Once a customer is aware of having hit a high billing demand for the month, the demand charge offers no reward for

controlling load any time that the customer's load is less that that prior demand.

- Rather than promoting conservation at high-cost times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times. For instance, in order to respond to demand charges effectively, customers will need to install equipment to monitor loads, interrupt discretionary load, and schedule deferrable loads. Moreover, lower energy charges will encourage increased electric use, some of which will likely occur in the peak period.

3. Excluding some charges from the net-metering credit

Q: Is exclusion of some energy charges from the net-metering credit an appropriate response to distributed generation?

A: Excluding some specific and narrowly-defined charges may be appropriate. For example, some jurisdictions, such as Vermont and Massachusetts, do not provide a net-metering credit for the charges that collect energy-efficiency and/or renewable funds and low-income energy assistance. Thus, the net-metering credit is slightly less than the full retail rate.

I recommend that the Commission similarly exclude the system benefit charge from the net-metering credit. The system benefit charge funds energy-efficiency and low-income programs across the state. Net-metered generation does little to reduce these costs recovered through the system benefit charge. The energy fed back into the system by distributed generation does not reduce the cost of the utility-funded energy-efficiency programs. Distributed-generation customers remain eligible for energy-efficiency services for all their energy use, not just their net consumption. Distributed solar generation will not significantly reduce the need for assistance to low-income customers unless those customers can participate in the net-metering program.[11]

Similarly, a policy decision to provide energy assistance to low-income customers through a ¢/kWh charge may imply a judgement that customers' ability to provide that assistance varies with their energy consumption. Energy exported to the distribution system does not substantially reduce the low-income customers' need for aid, or the distributed-generation customers' fair contribution to providing that assistance.

Q: Other than assessments for energy-efficiency and low-income energy assistance, are there any other charges that might be excluded from the net-metering credit?

A: Under some circumstances, there may be sufficient justification for excluding other charges that are added to utility bills to recover exogenously determined costs, rather than the costs of providing current and future service. Examples might include any distinct bill categories for recovery of abandoned plant or support of government services.

4. Time-varying rates

Q: Is imposition of time-varying rates an appropriate response to distributed generation?

[11] The Commission can encourage community solar programs to include low-income customers by including the low-income-assistance portion of the system benefits charge in the net-metering credit for projects meeting a threshold of low-income participants.

A: Time-varying rates, including time-of-use (TOU), variable peak pricing, critical peak pricing, and even real-time pricing can promote fair and efficient pricing, both for distributed-generation customers and those without distributed generation.[12] If the rates are properly designed and the metering and billing is not excessively expensive, time-varying rates can provide incentives to conserve, produce, or shift energy out of high-cost periods and onto low-cost periods. With time-varying rates, distributed-generation customers who draw energy at higher-cost times and provide excess to the system at lower-value times pay more than those that have the opposite pattern. In New Hampshire, time-varying rates are likely to increase the compensation for distributed solar projects, considering the higher energy prices in the on-peak hours (when solar panel produce most of their energy) and the concentration of system peak loads in the daytime.

Peak-period energy charges, best reflect costs that are driven by both peak demands and energy. Recovering costs through peak-period energy charges, rather than non-coincident demand charges, will encourage customers to reduce usage in high-cost, high-load periods, when:

- the system is heavily loaded;
- more expensive, less efficient and often more polluting generators otherwise normally would otherwise be dispatched; and/or
- transmission and distribution equipment is heavily loaded.

[12] Variable-peak pricing typically has a defined peak period, with the price in that period set daily, depending on market energy prices and system conditions. Critical-peak pricing includes a pre-specified price that will be applied when extreme conditions occur. Real-time pricing flows through market energy prices, possibly with load-dependent prices for generation and transmission capacity costs.

In order to charge time-varying rates for smaller customers, the utilities may need to upgrade their metering, communications and other systems.[13] Determination of whether these investments are cost-effective should be undertaken in conjunction with the Commission's investigation and development of grid modernization, and should focus on the cost-effectiveness of advanced metering for each stratum of energy use (starting with the largest consumers), rather than on whether customers have distributed generation.

B. Rate design approaches

Q: What rate design approaches are appropriate for distributed generation?

A: The simplest approach is net metering, with energy delivered to the distribution system being credited with the retail energy charge. In order for this approach to be equitable for larger customers that pay demand charges, and to provide effective and efficient price signals, the utilities should migrate retail rate designs from demand charges to time-varying rates.

As I noted above, some narrowly defined charges, such as the system benefit charge, may reasonably be excluded from the net-metering credit for energy delivered to the distribution utility by the distributed-generation customers.

For the current low penetration of distributed generation, net metering is probably the most appropriate default treatment for behind-the-meter generation.

Q: What factors would justify a change in the net-metering approach?

[13] I understand that Unitil has already installed advanced meters that have these capabilities.

A: A change in the net-metering approach might be appropriate once the Commission has access to additional load and cost data, and the amount of distributed generation on the system becomes more significant. As the Draft NARUC Manual on DER says, “decisions on DER compensation methodologies are not static determinations that can be made once and then left alone.”[14]

Q: Please describe the changes in data availability you anticipate.

A: The Commission currently has limited information about a number of important issues, including the load patterns on various parts of the distribution system, the effect of distributed solar generation on those loads and the costs of maintaining reliability, future grid-monitoring and control technology, and future metering technology. The near-term future of New Hampshire’s grid and metering technologies should be clarified in the course of the state-wide grid modernization efforts, pursuant to Commission Docket IR 15-296 and subsequent grid modernization dockets. Implementation of those technologies will provide the Commission with more data on the nature of the stresses on the distribution system and the extent to which distributed solar generation would increase or decrease those stresses and associated costs. Over time, the utilities should assemble additional data on the timing of peak loads on various parts of the distribution system, the variation of load costs over time, the rate of implementation of distributed solar on the system, the costs of adapting the distribution system to high levels of distributed-generation penetration, the costs of distributed storage, and other topics that will be considered in Docket IR 15-296 and subsequent proceedings.

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[14] Draft NARUC Draft Manual on DER, p. 61.

To the extent that the Commission authorizes any pricing and planning pilot programs in this docket or subsequent dockets, the results of those pilots also will enhance the Commission's ability to determine whether alternative tariffs are required and if so, to design efficient and equitable alternative tariffs.

In addition to data developed in New Hampshire, the next several years will give the Commission an opportunity to observe and analyze the results of policies implemented in other states, where distributed generation penetration and/or grid-modernization efforts are more mature.

Q: How could the Commission determine whether the amount of distributed generation on the system has become significant enough to require further review net metering policies?

A: One factor that could trigger a review of distributed-generation ratemaking would be a high saturation of distributed generation on one or more feeder. The Commission may want to set a default response to high saturation, to avoid net export from the distribution feeder through the substation onto the transmission lines, at least until the costs of modifying the substation and transmission control systems have been assessed. An example of a default response would be to provide that, once the net backflow from distributed generation onto any feeder exceeds half the capacity of the feeder, the net-metering credit will fall by 1¢/kWh for any new generation on that feeder. By "net backflow," I mean the surplus of energy delivered to the feeder by distributed generation, minus the load on the feeder at that time. The reduction in the credit would start before the backflow is large enough to stress the feeder. If the net flow continues to increase, the net-metering credit for new installations could be reduced by a further 1¢/kWh each time that backflow increases by an additional 10% of feeder capacity. Once the installed distributed generation is sufficient to produce backfeed exceeding the feeder capacity, further net-metering installations would be prohibited, unless they are designed to avoid exporting power to the feeder at low-load levels.[15]

This approach would be relatively simple for utilities to administer and for potential distributed-generation customers to understand. It would also provide a level of price certainty for distributed-generation customers, who would know how their net-metering credit would compare to their retail rates. Once an installation was authorized, the customer would know that the net-metering credit will follow retail rates, keeping the net utility bills fairly predictable.[16]

In addition to the concentration of distributed generation in individual feeders, the Commission should monitor the capacity of net-metered generation as a percentage of utility peak.

I recommend that the Commission direct that, once that ratio reaches an initial threshold, such as 5%, Staff convene a stakeholder process to consider whether changes to net metering, and related regulations or rate mechanisms, are warranted. I also recommend that the Commission commit to a second penetration threshold at 10%, at which point it would initiate a adjudicatory

[15] Indeed, installations with storage or other controls to ensure that they will not overload the distribution circuit should be eligible for the full net-metering rate, regardless of whether the feeder has a penetration exceeding the thresholds I suggest above. This policy would provide an incentive to add storage to installations on potentially constrained circuits.

[16] If the Commission adopts a capacity-constraint trigger for reduced compensation of distributed generation, the Commission must ensure that the utilities provide transparent information regarding circuit capability, minimum daytime loads, and installed and pending distributed generation installations.

proceeding to determine whether any changes need to be made to the net metering program.[17]

This time frame would be consistent with the Draft NARUC Manual on DER, which indicates that few complex regulatory mechanisms are needed to support distributed generation at the sub-5% level, but upon reaching a more meaningful level of penetration, such as 10%, more complex regulatory mechanisms and grid infrastructure may be needed to complement the continued expansion of distributed generation resources.[18]

To minimize disruption during any future review processes, the Commission should specify that it will grandfather existing systems (and those for which interconnection applications are pending) in any future order directing modifications to compensation levels or other major requirements for participating systems.

Establishing rules for limiting the net distributed-generation capacity by feeder and for monitoring the capacity of net-metered generation as a percentage of utility peak will be more efficient than an arbitrary MW-based cap, and would eliminate the need for any such cap. The amount of distributed solar generation that the distribution can accommodate depends on the spatial distribution of the generation around the system; the ability of the feeders and the system to absorb distributed generation will increase with technological improvements in the distributed generation itself and in the monitoring and control capability of the grid.

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[17] The Commission may wish to revise this threshold upward, if it has recently conducted a thorough review in response to the stakeholder process at the 5% level or other developments, such as grid-modernization results.

[18] Draft NARUC Manual on DER p. 61-62.

Q: Would the approach you have sketched out be appropriate for all net-metering customers, at least for the next several years?

A: Yes, that would be a reasonable approach. The simplicity and predictability of the structure I have proposed are particularly important for small systems (say, under 20 kW AC output) for residential and small-commercial customers, one can easily be discouraged by complexity, uncertainty, and other process barriers. For larger customers, with projects over 100 kW, more complex processes and ratemaking procedures may be tolerable, but not necessarily warranted.

Q: Can the Commission do anything to help extend the benefits of distributed solar to customers who lack the credit quality necessary to purchase or lease solar equipment?

A: The Commission could require the utilities to develop solar programs for low-income customers, which might be structured similar to a demand-side management (DSM) program, with the utility accepting the payment risk and with the costs and benefits of the solar equipment passing on to future residents in the property.

Q: Are there any other efforts that the Commission should consider in this proceeding?

A: Yes. I recommend that the Commission consider authorizing certain limited pilot projects to test out aspects of net-metering pricing and planning.

I understand that the City of Lebanon may propose a case study or pilot project combining net metering with time-varying rates. A pilot of that nature would be worthy of consideration. For the reasons outlined above, time-varying rates can be beneficial generally, and provide particular benefits in the context of distributed generation. Because time-varying rates require infrastructure and monitoring investments, it would be appropriate to consider a case study or pilot project prior to deciding how to further roll-out such rate availability in connection with the Commission's larger grid modernization efforts.

In addition, I recommend that the Commission consider the benefits that a locational pilot could offer. To this end, the Commission could direct the utilities to identify an area or areas in which targeted distributed generation projects, potentially in combination with targeted energy-efficiency programming, could defer or avoid a specific major local transmission or distribution project. A pilot of this nature would inform future efforts to conserve resources and lower electric rates through strategic smaller investments that empower consumers as grid-participants. Non-transmission alternatives have a particularly high value in states like New Hampshire with culturally and economically significant natural landscapes, increasing the barriers to siting transmission and major distribution projects and increasing their costs.

VI. Summary of Recommendations

Q: Please summarize your recommendations.

A: I recommend that the Commission:

- Maintain the net metering program.
- Exclude the system benefit charge from the net-metering credit.
- Avoid setting any firm cap on net-metering installations.
- Establish declining net-metering credits for new installations on feeders for which hourly maximum distributed-generation output net of load

exceeds half the feeder capacity, except for systems that do not add to the reverse load flow (e.g., with storage).

- Review the feasibility of providing incentives for group net-metering projects that serve targeted customer groups, especially low-income customers.
- Require that a stakeholder process be initiated once installed and pending net-metering capacity exceeds 5% of peak load, to consider whether any changes are warranted in compensation for additional net-metering installations.
- Initiate a regulatory review of net-metering arrangements once installed and pending net-metering capacity exceeds 10% of peak load.
- Initiate a review of rate design, to investigate the feasibility of replacing demand charges with more efficient time-varying rates and of expanding time-varying rates to additional tariff classes.
- Move toward full decoupling of distribution revenue from sales, to protect utilities from short-term lost revenues from distributed generation and energy-efficiency programs.
- Invite proposals for net-metering pilot programs, including pilots that test the use of time-varying rates in connection with net metering and that focus on alleviating locational constraints using distributed generation, targeted efficiency and other non-transmission alternatives .

Q: Does this conclude your testimony?

A: Yes.