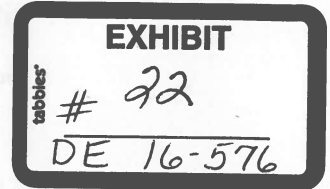


STATE OF NEW HAMPSHIRE  
BEFORE THE PUBLIC UTILITIES COMMISSION



Development of New Alternative Net )  
Metering Tariffs and/or Other Regulatory )  
Mechanisms and Tariffs for Customer- )  
Generators )

Docket No. DE 16-576

DIRECT TESTIMONY OF  
PAUL CHERNICK  
ON BEHALF OF  
CONSERVATION LAW FOUNDATION

Resource Insight, Inc.

OCTOBER 24, 2016

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Exhibit PLC-1

*Professional Qualifications of Paul Chernick*

1 **I. Identification & Qualifications**

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

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

5 **Q: Summarize your professional education and experience.**

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

10 I was a utility analyst for the Massachusetts Attorney General for more  
11 than three years, and was involved in numerous aspects of utility rate design,  
12 costing, load forecasting, and the evaluation of power supply options. Since  
13 1981, I have been a consultant in utility regulation and planning, first as a  
14 research associate at Analysis and Inference, after 1986 as president of PLC,  
15 Inc., and in my current position at Resource Insight. In these capacities, I have  
16 advised a variety of clients on utility matters.

17 My work has considered, among other things, the cost-effectiveness of  
18 prospective new electric generation plants and transmission lines, retrospec-  
19 tive review of generation-planning decisions, ratemaking for plant under con-  
20 struction, ratemaking for excess and/or uneconomical plant entering service,  
21 conservation program design, cost recovery for utility efficiency programs, the  
22 valuation of environmental externalities from energy production and use,  
23 allocation of costs of service between rate classes and jurisdictions, design of

1 retail and wholesale rates, and performance-based ratemaking and cost re-  
2 covery in restructured gas and electric industries. My professional qualifica-  
3 tions are further summarized in Exhibit PLC-1.

4 **Q: Have you testified previously in utility proceedings?**

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

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

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

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

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

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

25 A: I have worked on numerous projects concerning the determination of rates for  
26 customers with behind-the-meter generation and for non-utility power

1 suppliers, including the valuation of distributed resources, since the early  
2 1980s, as listed in Exhibit PLC-1. Among other things, I was a member of the  
3 team that estimated the New England-wide avoided costs for energy-efficiency  
4 programs in 1999, 2003, 2007, 2019, 2011, and 2013.

## 5 **II. Introduction**

6 **Q: On whose behalf are you testifying?**

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

8 **Q: What is the scope of your testimony?**

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

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

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

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

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

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

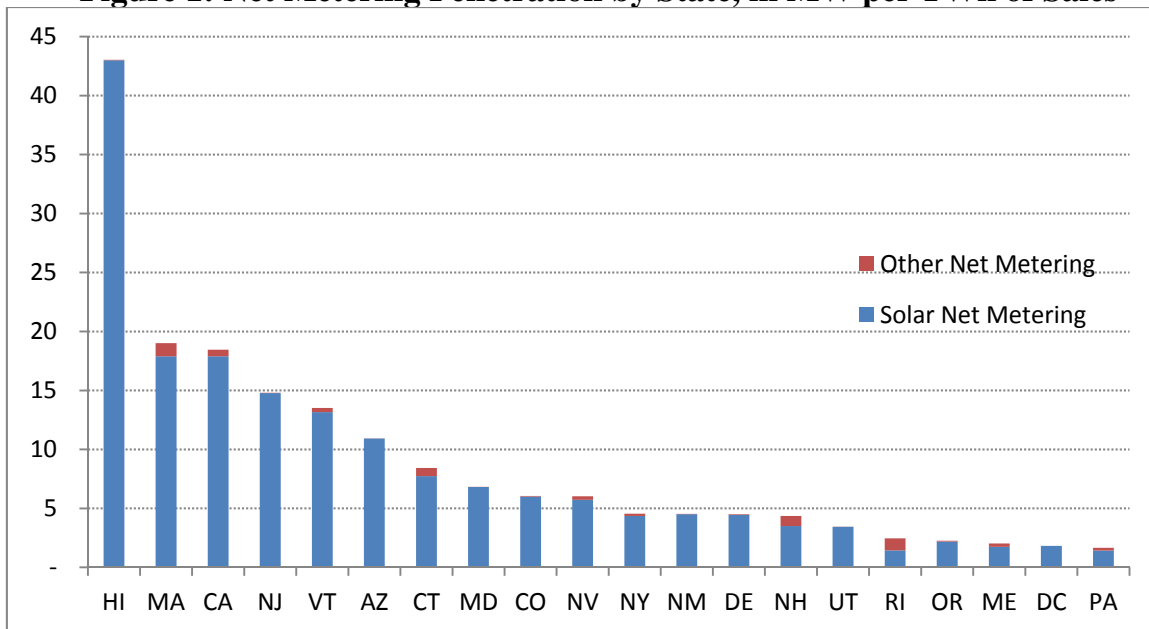
- 4 • **Rate effects on all customers.** The rate effects of net metering are  
5 unlikely to be significant at the low penetrations of net metering  
6 experienced in New Hampshire. Whether the net effect of net metering is  
7 to reduce costs for other customers is not yet clear.
- 8 • **Alternative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

24 **A. *Net Metering in New Hampshire***

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

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

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



12  
13

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

1 Hampshire comes in 14<sup>th</sup> nationwide in capacity per unit retail sales, and  
2 probably 15<sup>th</sup> in energy after Utah.

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

5 A: New Hampshire has much less net-metered generation than the leading states.  
6 Hawaii has so much solar net-metered generation (about 25% of peak load)  
7 that reverse flows occur on parts of the distribution system; the Hawaii Public  
8 Utilities Commission has reduced the rate for power exported to the  
9 distribution system from the retail rate to the still-high wholesale prices  
10 (15¢/kWh to 28¢/kWh, depending on the island) and implemented minimum  
11 bills. Several of the other states with the highest net-metering penetrations—  
12 including California, Massachusetts, and Vermont—have considered changes  
13 in their net-metering arrangements, and have settled on relatively minor  
14 changes in billing arrangements.

15 According to EIA, New Hampshire’s net-metered capacity is  
16 approximately 48 MW, or 2% of ISO-NE’s 2,500 MW weather-normalized  
17 2016 forecast for the state.<sup>1</sup> Vermont reports 135 MW of net-metered capacity  
18 as of March 2016, or over 13% of the state’s 1,000 MW peak.<sup>2</sup> Net-metered

---

<sup>1</sup> 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.

<sup>2</sup> 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](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.



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

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

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

17 ***B. Framework for Evaluating Rates for Distributed Generation***

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

---

<sup>3</sup> 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...”)

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

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

### 6 **III. Costs Avoided by Distributed Solar**

7 **Q: What are benefits of distributed solar energy?**

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

- 9 • Avoided generation energy costs.
- 10 • Avoided generation capacity costs.<sup>4</sup>
- 11 • Reduced transmission and distribution line losses.
- 12 • Avoided load-related transmission upgrades.
- 13 • Avoided load-related distribution upgrades.
- 14 • Reduced wear and tear on transmission and distribution equipment.
- 15 • Reduced emissions of carbon dioxide (CO<sub>2</sub>), sulfur dioxide (SO<sub>2</sub>), oxides of  
16 nitrogen (NO<sub>x</sub>), air toxics, and fine particulates.
- 17 • Reduced effects of power generation on water consumption and water  
18 quality.
- 19 • Reduced market prices for natural gas, electric energy and capacity prices.
- 20 • Reduced sensitivity of power-supply costs to fuel prices and market  
21 conditions.
- 22 • Reduced cost of environmental compliance.

---

<sup>4</sup> 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.

- 1       • Local employment and economic stimulus.

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

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

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

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

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

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

23      A: The generation capacity charges for New Hampshire customers are determined  
24      by the zonal load coincident with the ISO-NE annual peak. Table 1 summarizes  
25      the ISO-NE peak hours over the past 16 years. The peak load occurs most often

1 in the hour from 2 PM TO 3 PM, when the solar equipment would be generating,  
2 especially on the sunny days that tend to drive summer peaks.

3 **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

4 The allocation of transmission costs is based on monthly zonal peaks,  
5 rather than the ISO-NE system peak. Table 2 provides the monthly peak hours  
6 for the New Hampshire zone, from ISO-NE data for March 2003 to December  
7 2015. Most of the monthly zonal peaks from May to September are in daylight  
8 hours, when solar would reduce loads, while the peaks in the other months  
9 largely occur after dark.

1 **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	-	-	-	-	-	-	-	-

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

1  
2

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

HE	Month											
	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	-	-	-	-

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

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

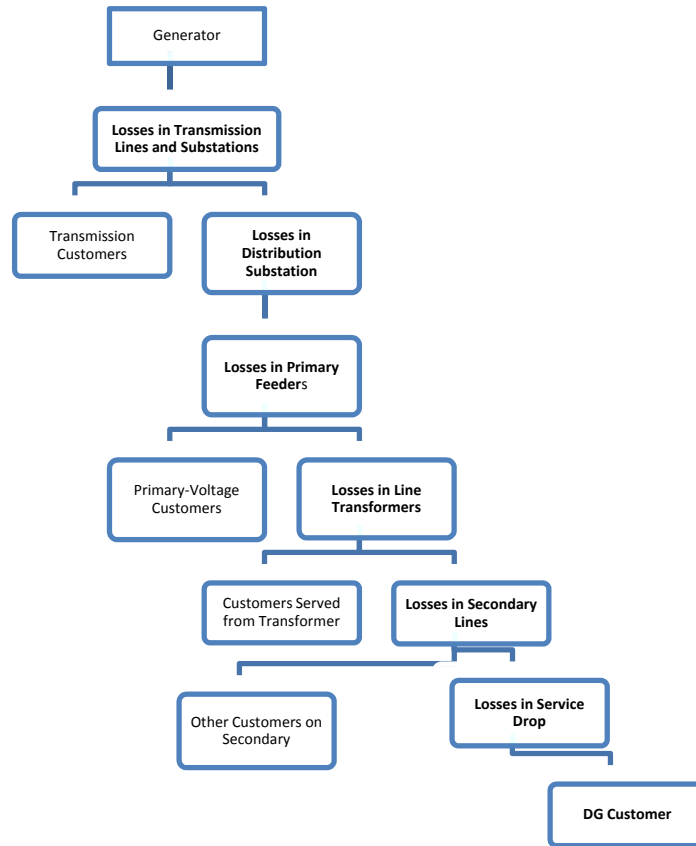
8 A: Yes. ISO-NE reflects behind-the-meter solar generation in its load forecasts,  
9 which determine the amount of capacity acquired in the forward capacity  
10 auctions.

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

13 A: The losses in conductors (including transmission and distribution lines and in  
14 transformers) varies with the square of the power flowing through the wire, so  
15 a 1% reduction in load reduces losses by about 2%. The levels of conductor

1 losses from the generators to a distributed generation customer at secondary  
2 voltage (such as a residential customer) are illustrated in Figure 2.

3 **Figure 2: Line-Loss Schematic**



4  
5 Reducing the DG customer's load reduces the losses in the service drop  
6 from the street to the customer, the secondary line (if any) serving that  
7 customer, the line transformers, the distribution feeder, the distribution  
8 substation, and probably several transmission lines and transmission  
9 substations. Rates are generally designed to collect average line losses from  
10 customers, so any reduction in line losses above the average level flows to all  
11 customers. For example, the average energy line-loss value included in the  
12 allocation of ISO-NE locational marginal costs to customers in the New  
13 Hampshire zone would tend to decline with the addition of distributed  
14 generation. The same is true for the average peak-hour line loss factor

1 embedded in the New Hampshire zonal load for the assignment of generation  
2 capacity responsibility.

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

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

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

---

<sup>5</sup> 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.



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

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

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

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

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

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

25       A: Existing transmission and distribution equipment wears out faster if it is more  
26       heavily loaded. The capacities of transformers and underground power lines,

1 in particular are limited by the build-up of heat created by electric energy  
2 losses in the equipment. Every time a transformer approaches or exceeds its  
3 rated capacity (a common occurrence, since transformers can typically operate  
4 above their rated capacity for short periods of time), its internal insulation  
5 deteriorates and it loses a portion of its useful life. Long hours of high loads  
6 result in heat building up in lines (especially underground lines) and  
7 transformers, increasing the damage of peak loadings.

8 Figure 3 illustrates the effect of the length of the peak load, and the load  
9 in preceding hours, on the load that a transformer can carry without losing  
10 operating life.<sup>6</sup> The initial load in Figure 3 is defined as the maximum of the  
11 average load in the preceding two hours or 24 hours. A transformer that was  
12 loaded to 50% of its rating in the afternoon can endure an overload of 190%  
13 for 30 minutes or 160% for an hour. If the afternoon load was 90% of the  
14 transformer rating, it could only carry 160% of its rated load for 30 minutes or  
15 140% for an hour.<sup>7</sup>

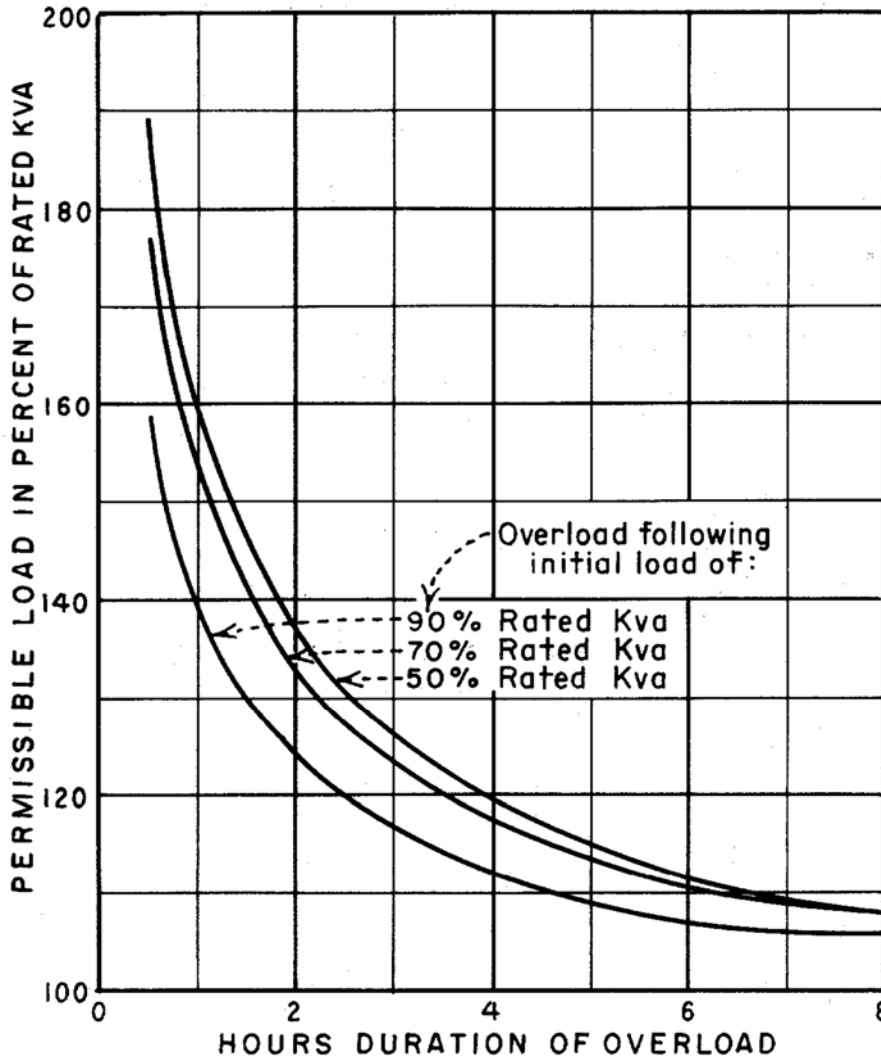
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<sup>6</sup> The figure is from Permissible Loading of Oil-Immersed Transformers and Regulators, United States Department of the Interior, Bureau of Reclamation, Facilities Engineering Branch, Denver Office, April 1991. This specific example is for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

<sup>7</sup> 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.

1

**Figure 3: Permissible Overload for Varying Periods**



2

3

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.

9

10

11

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

1 equipment and reducing the rate of failure. This is particularly relevant for line  
2 transformers, for which the utility will not usually be able to closely monitor  
3 transformer loading and temperature.

4 **Q: Do the same issues apply to overhead lines?**

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

11 **Q: Do those benefits flow to all utility customers?**

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

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

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

- 20 • carbon dioxide from burning coal, oil and gas;
- 21 • sulfur dioxide from burning coal and oil plants;
- 22 • NOx from burning coal, wood, oil and gas;
- 23 • Fine particulates from burning coal, wood, and oil;<sup>8</sup> and

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

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

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

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

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

18   A: For any future statewide or regional cap on emissions (most likely for carbon,  
19   although it could also be applied to NO<sub>x</sub>), lower emissions from electric  
20   generation (due to distributed renewables) would make compliance easier and  
21   allow for less stringent controls on other end uses, from building heating to  
22   transportation.

#### 23   **IV. Costs Imposed by Distributed Solar**

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

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

4           However, the customer still requires a connection to the grid for those  
5 hours when the solar panels are not generating all of the electricity  
6 required on premises. An example of this is at night, or on cloudy days.  
7 The connection is also required to export and sell any excess energy that  
8 the customer may produce.

9           Solar customers benefit from having enough power plants being built to  
10 provide adequate backup when the sun is not shining. It is important to  
11 note that often the customer’s demand for electricity exceeds the capacity  
12 of the solar panels. That makes solar energy an intermittent and  
13 unpredictable power source. Additionally, its energy production is  
14 generally not coincident with peak demand of most utilities in the United  
15 States.

16           The customer still requires a meter, a call center to answer questions about  
17 monthly bills, and other vital services. It is only equitable that the solar  
18 customer should pay the utility for a share of those services. However, net  
19 metering policy prevents this from happening. (“Rethinking Rationale for  
20 Net Metering, Quantifying Subsidy from Non-Solar to Solar Customers;”  
21 Barbara Alexander, Ashley Brown, and Ahmad Faruqui; *Public Utilities*  
22 *Fortnightly*, Volume 154, No. 10, pp. 28–33)

23 **Q: What is incorrect about this argument?**

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

29           Second, there is no additional cost to the utility for the distributed  
30 generation grid connection, either for nights and cloudy days or “to export and

1 sell any excess energy.”<sup>9</sup> The same grid connection that supplies the customer  
2 without distributed generation will supply the customer with distributed  
3 generation and will also carry the energy exported to the distribution system.

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

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

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

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

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<sup>9</sup> Net metering is not usually treated as a sale of energy, in any case.

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

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

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

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

## 14 **V. Rate Design for Distributed Generation**

### 15 **A. *Rate Design Components***

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

18 A: The most common proposals for regulatory action include:

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



1 *I. Customer Charges*

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

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

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

24 High customer charges run the risk of encouraging customers to install  
25 additional electrical storage and leave the utility system. If the fixed charge is

1 higher than the utility's savings from losing the customer, the decision to cut  
2 the cord may be economically inefficient.

3 2. *Demand Charges*

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

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

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

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

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

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

24 Many costs in any particular year are largely determined by the  
25 cumulative investment and construction commitments in the past, and are

1 hence fixed by Definition 2. However, even though transmission and  
2 distribution costs are overwhelmingly fixed over the year, none of them are  
3 fixed over load, since generation and transmission is added only for load-  
4 related reliability and energy savings. Hence, they are not fixed by Definition  
5 1 and should be recovered through rates that vary with usage and encourage  
6 customers to reduce and control the usage that contributes to the costs.

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

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

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

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

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

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

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

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

11 3. *Excluding some charges from the net-metering credit*

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

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

19 I recommend that the Commission similarly exclude the system benefit  
20 charge from the net-metering credit. The system benefit charge funds energy-  
21 efficiency and low-income programs across the state. Net-metered generation  
22 does little to reduce these costs recovered through the system benefit charge.  
23 The energy fed back into the system by distributed generation does not reduce  
24 the cost of the utility-funded energy-efficiency programs. Distributed-  
25 generation customers remain eligible for energy-efficiency services for all

1 their energy use, not just their net consumption. Distributed solar generation  
2 will not significantly reduce the need for assistance to low-income customers  
3 unless those customers can participate in the net-metering program.<sup>11</sup>

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

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

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

18 4. *Time-varying rates*

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

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<sup>11</sup> 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.

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

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

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

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<sup>12</sup> 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.

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

8           ***B. Rate design approaches***

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

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

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

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

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

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<sup>13</sup> I understand that Unitil has already installed advanced meters that have these capabilities.



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

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

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

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<sup>14</sup> Draft NARUC Draft Manual on DER, p. 61.

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

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

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

12 A: One factor that could trigger a review of distributed-generation ratemaking  
13 would be a high saturation of distributed generation on one or more feeder. The  
14 Commission may want to set a default response to high saturation, to avoid net  
15 export from the distribution feeder through the substation onto the  
16 transmission lines, at least until the costs of modifying the substation and  
17 transmission control systems have been assessed. An example of a default  
18 response would be to provide that, once the net backflow from distributed  
19 generation onto any feeder exceeds half the capacity of the feeder, the net-  
20 metering credit will fall by 1¢/kWh for any new generation on that feeder. By  
21 “net backflow,” I mean the surplus of energy delivered to the feeder by  
22 distributed generation, minus the load on the feeder at that time. The reduction  
23 in the credit would start before the backflow is large enough to stress the feeder.  
24 If the net flow continues to increase, the net-metering credit for new  
25 installations could be reduced by a further 1¢/kWh each time that backflow  
26 increases by an additional 10% of feeder capacity. Once the installed

1 distributed generation is sufficient to produce backfeed exceeding the feeder  
2 capacity, further net-metering installations would be prohibited, unless they  
3 are designed to avoid exporting power to the feeder at low-load levels.<sup>15</sup>

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

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

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

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<sup>15</sup> 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.

<sup>16</sup> 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.

1 proceeding to determine whether any changes need to be made to the net  
2 metering program.<sup>17</sup>

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

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

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

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<sup>17</sup> 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.

<sup>18</sup> Draft NARUC Manual on DER p. 61-62.

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

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

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

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

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

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

22 I understand that the City of Lebanon may propose a case study or pilot  
23 project combining net metering with time-varying rates. A pilot of that nature  
24 would be worthy of consideration. For the reasons outlined above, time-  
25 varying rates can be beneficial generally, and provide particular benefits in the  
26 context of distributed generation. Because time-varying rates require

1 infrastructure and monitoring investments, it would be appropriate to consider  
2 a case study or pilot project prior to deciding how to further roll-out such rate  
3 availability in connection with the Commission's larger grid modernization  
4 efforts.

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

## 17 **VI. Summary of Recommendations**

18 **Q: Please summarize your recommendations.**

19 **A:** I recommend that the Commission:

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

- 1 exceeds half the feeder capacity, except for systems that do not add to the  
2 reverse load flow (e.g., with storage).
- 3 • Review the feasibility of providing incentives for group net-metering  
4 projects that serve targeted customer groups, especially low-income  
5 customers.
  - 6 • Require that a stakeholder process be initiated once installed and pending  
7 net-metering capacity exceeds 5% of peak load, to consider whether any  
8 changes are warranted in compensation for additional net-metering  
9 installations.
  - 10 • Initiate a regulatory review of net-metering arrangements once installed  
11 and pending net-metering capacity exceeds 10% of peak load.
  - 12 • Initiate a review of rate design, to investigate the feasibility of replacing  
13 demand charges with more efficient time-varying rates and of expanding  
14 time-varying rates to additional tariff classes.
  - 15 • Move toward full decoupling of distribution revenue from sales, to  
16 protect utilities from short-term lost revenues from distributed generation  
17 and energy-efficiency programs.
  - 18 • Invite proposals for net-metering pilot programs, including pilots that test  
19 the use of time-varying rates in connection with net metering and that  
20 focus on alleviating locational constraints using distributed generation,  
21 targeted efficiency and other non-transmission alternatives .

22 **Q: Does this conclude your testimony?**

23 A: Yes.