BEFORE THE NEW
HAMPSHIRE PUBLIC
UTILITIES COMMISSION

EXHIBIT
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ELECTRIC DISTRIBUTION UTILITIES

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

DIRECT TESTIMONY OF R. THOMAS BEACH ON BEHALF OF THE ALLIANCE FOR SOLAR CHOICE

OCTOBER 24, 2016

Executive Summary

This testimony on behalf of The Alliance for Solar Choice (TASC) responds to the Commission's request for proposals addressing the Legislature's direction in House Bill 1116 to develop new tariffs for net energy metering (NEM) in New Hampshire. The stated goals of HB 1116 are, first, to continue to allow reasonable opportunities for electric customers to invest in and to install renewable distributed generation (DG) behind the meter on their own premises; second, to provide fair compensation for this locally-produced power; and, third, to allocate the benefits and costs of these new, clean energy sources in a fair and transparent way among all ratepayers.

The first requirement of HB 1116 is that the Commission consider both the benefits and costs of renewable DG. This testimony proposes a benefit-cost methodology for valuing customer-sited DG resources. This approach builds upon the widely-used, industry-standard tests for assessing the cost-effectiveness of other types of demand-side resources, such as energy efficiency programs. These analyses assess the benefits and costs of DG resources from multiple perspectives, including those of the principal stakeholders in DG development, including (1) participating customer-generators, (2) other non-participating ratepayers, and (3) the utility system and society as a whole. The goal of the regulator should be to balance the interests of all of these stakeholders, who collectively constitute the public interest in developing DG technologies.

The Commission should adopt a benefit/cost methodology for net metered DG that has four key attributes:

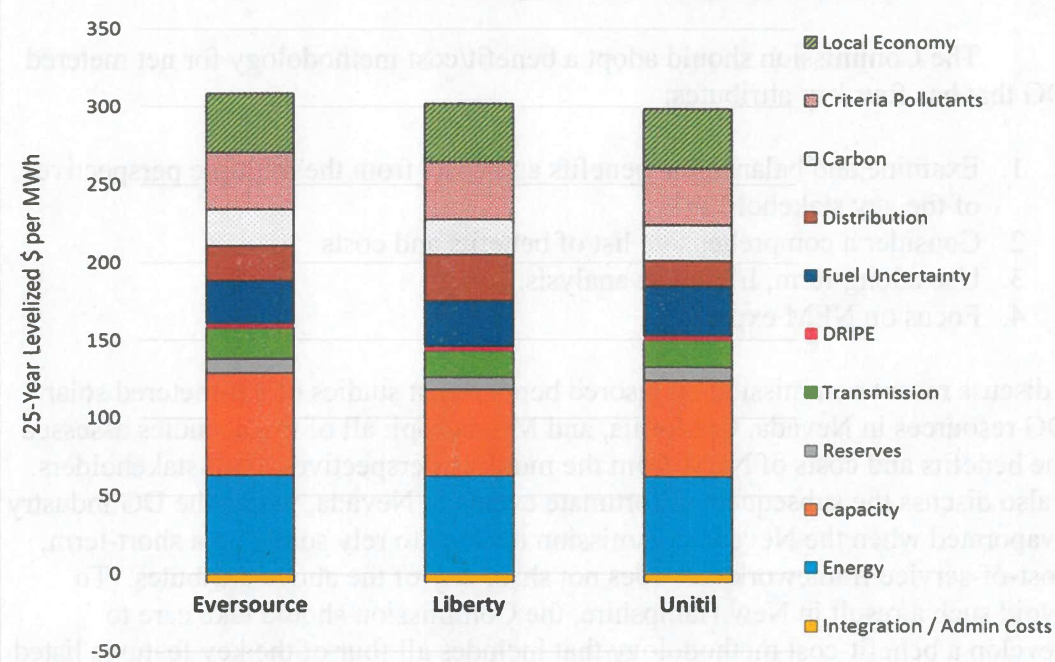
1. Examine and balance the benefits and costs from the multiple perspectives of the key stakeholders.
2. Consider a comprehensive list of benefits and costs.
3. Use a long-term, life-cycle analysis.
4. Focus on NEM exports.

I discuss recent commission-sponsored benefit-cost studies of net-metered solar DG resources in Nevada, California, and Mississippi; all of these studies assessed the benefits and costs of NEM from the multiple perspectives of all stakeholders. I also discuss the subsequent unfortunate events in Nevada, where the DG industry evaporated when the Nevada commission decided to rely solely on a short-term, cost-of-service framework that does not share any of the above attributes. To avoid such a result in New Hampshire, the Commission should take care to develop a benefit-cost methodology that includes all four of the key features listed above.

I present a close analysis of the net metering transaction, for several reasons. First, it illuminates how DG differs from other demand-side resources. DG customers are not just consumers of power, but also at times produce power for export to the utility system. Second, I discuss why the essence of net metering is valuing the power which DG customers will export to the grid. Third, I dispel several common myths about net metering, including the misplaced ideas that NEM customers use the grid more than regular utility customers, that a NEM customer with a low or zero bill means that the customer has not paid for its use of the grid, and that the grid provides a service to "store" DG output for future consumption.

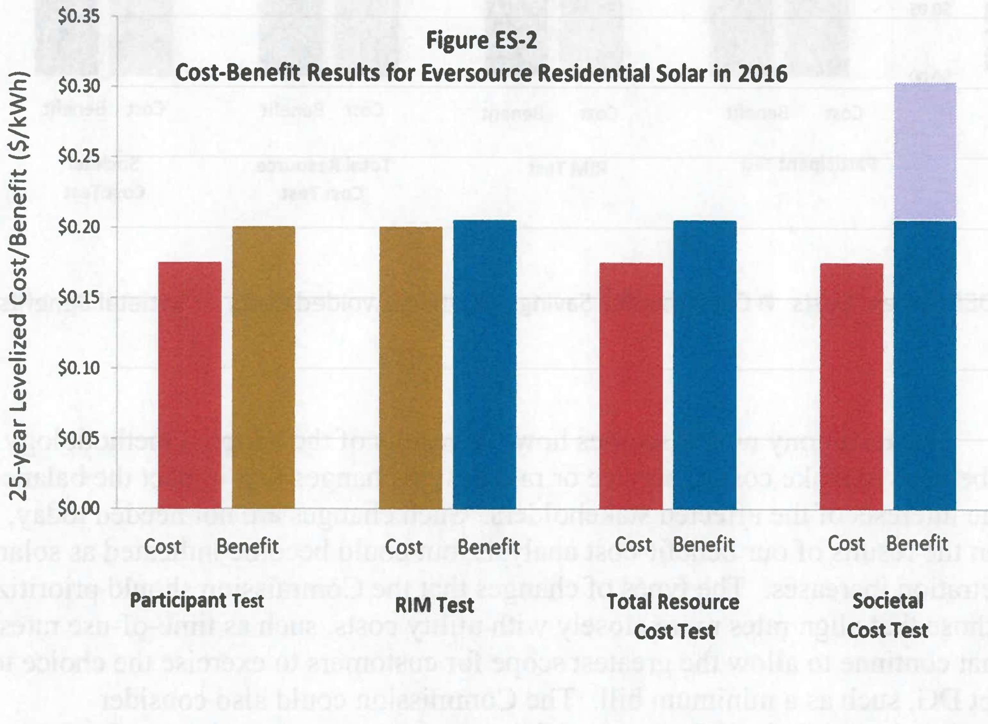
The testimony reviews the specific benefits and costs that should be examined in establishing the cost-effectiveness of DG. All of these benefits and costs have been quantified in other similar studies, and well-accepted techniques are available for this task. If the Commission is uncertain about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that benefit or cost, but to examine several cases that span a range of reasonable values for this benefit or cost. **Figure ES-1** shows the quantification of the principal benefits of solar DG for the each of the utilities, expressed in 25-year levelized cents per kWh.

Figure ES-1: Summary of Solar DG Benefits

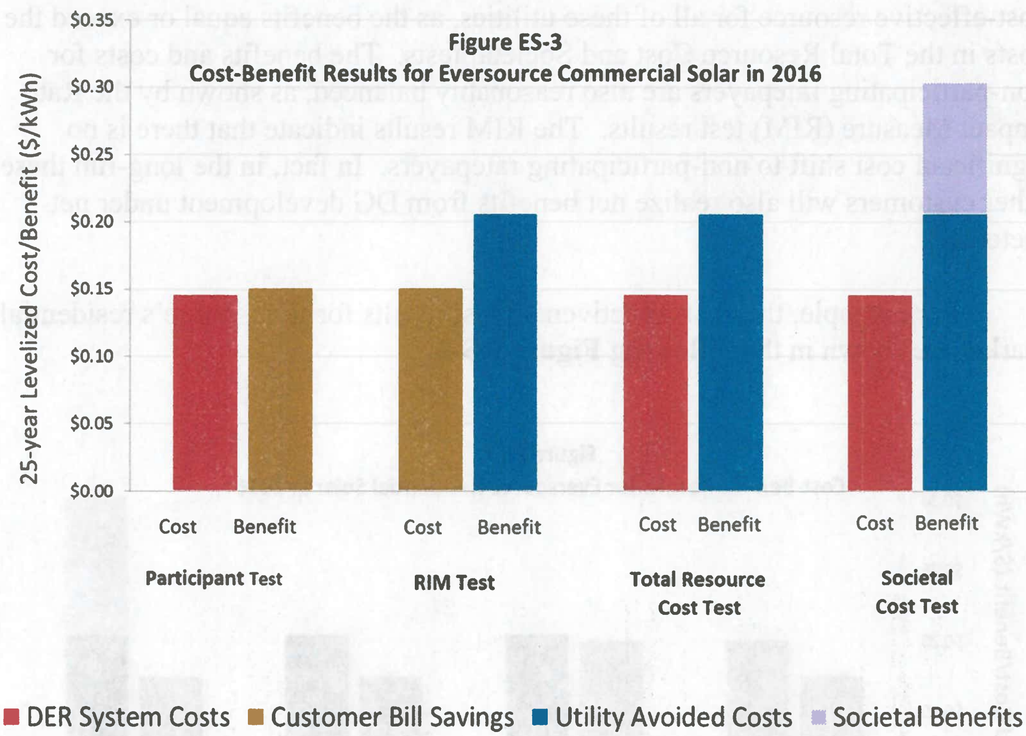


I use our preferred methodology to present benefit-cost analyses of net-metered distributed solar generation in each of the three investor-owned utility service territories in New Hampshire. These analyses conclude that solar DG is a cost-effective resource for all of these utilities, as the benefits equal or exceed the costs in the Total Resource Cost and Societal tests. The benefits and costs for non-participating ratepayers are also reasonably balanced, as shown by the Rate Impact Measure (RIM) test results. The RIM results indicate that there is no significant cost shift to non-participating ratepayers. In fact, in the long-run these other customers will also realize net benefits from DG development under net metering.

For example, the cost-effectiveness test results for Eversource's residential market are shown in the following **Figure ES-2**.



And **Figure ES-3** shows the comparable results for Eversource's commercial customers.



The testimony next discusses how the results of the adopted methodology can be used to make cost of service or rate design changes that impact the balance of the interests of the affected stakeholders. Such changes are not needed today, given the results of our benefit-cost analysis, but could become indicated as solar penetration increases. The types of changes that the Commission should prioritize are those that align rates more closely with utility costs, such as time-of-use rates, or that continue to allow the greatest scope for customers to exercise the choice to adopt DG, such as a minimum bill. The Commission could also consider removing the public benefit charge and the electricity consumption tax from the NEM export rate, so that all customers contribute to these public purpose levies on the equitable basis of the power that they take from the utility system.

The Commission should avoid fixed charges, demand charges, or rate design changes that apply only to DG customers, due to problems with failure to reflect cost causation, lack of customer acceptance, undue discrimination, possible PURPA issues, and the future potential for customer bypass of the utility system.

Finally, the testimony supports the continuation of net metering in New Hampshire without further limits on the aggregate capacity of NEM systems and with no change to the present 1 MW size limit for an individual NEM system. Any future review of net metering tariffs and associated rate designs should occur within the data-rich context of a utility's general rate case (GRC). Finally, it is reasonable to adopt a cost recovery procedure so that the utilities can recover lost revenues (net of avoided short-run costs) that result from new DG installations in the years prior to the utility's next GRC. Such timely cost recovery holds the utility harmless from DG development between rate cases. It would also remove the perverse incentive for the utility to discourage customers from investing in local renewable energy systems that will provide long-term benefits and lower overall system costs for all customers, as well as significant societal benefits for the economy and environment of New Hampshire.

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Appendices

I. INTRODUCTION / QUALIFICATIONS

Q1: Please state for the record your name, position, and business address.

A1: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q2: Please describe your experience and qualifications.

A2: My experience and qualifications are described in my *curriculum vitae*, attached as **Appendix A**. As reflected in my CV, I have more than 30 years of experience in the natural gas and electricity industries. I began my career in 1981 on the staff at the California Public Utilities Commission ("CPUC"), working on the implementation of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). Since 1989, I have had a private consulting practice on energy issues and have testified or submitted testimony on numerous occasions before state regulatory commissions in sixteen states. My CV includes a list of the formal testimony that I have sponsored in various state regulatory proceedings concerning electric and gas utilities, as of the end of 2015.

Q3: Have you testified previously before this Commission?

A3: No, I have not.

Q4: Please describe more specifically your experience on benefit-cost issues concerning distributed generation.

A4: In addition to working on the initial implementation of PURPA while on the staff at the CPUC, in private practice I have represented the full range of qualifying facility ("QF") technologies – both renewable small power producers as well as gas-fired cogeneration QFs – on avoided cost pricing issues before the utilities commissions in California, Idaho, Montana, North Carolina, Oregon, Utah, and Nevada. With respect to benefit-cost issues concerning renewable distributed generation ("DG"), I have sponsored testimony on net energy metering ("NEM") and solar economics in California, Colorado, Idaho, Minnesota, New Mexico, North Carolina, South Carolina, Texas, and Virginia. In the last three years, I have co-authored benefit-cost studies of NEM or distributed solar generation in Arizona, Colorado, North Carolina, and California. I also co-authored the chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues released in 2013 that is designed to provide policymakers with tools to address key questions concerning distributed generation resources.

Q5: On whose behalf are you testifying in this proceeding?

A5: I am testifying on behalf of The Alliance for Solar Choice ("TASC").

II. BACKGROUND

Q6: What is net energy metering under New Hampshire law?

A6: Net energy metering was first enacted into law in 1998 through HB 485 as a new section of the Limited Electrical Energy Producers Act (RSA 362-A *et seq.*). The definition of "net energy metering" added by HB 485 remains intact today:

> "Net energy metering" means measuring the difference between the electricity supplied over the electric distribution system and the electricity generated by an eligible customer-generator which is fed back into the electric distribution system over a billing period.[1]

Q7: Is the New Hampshire definition consistent with how the term "net metering" is generally used across the country?

A7: Yes, this definition is consistent with the prevailing definition of net metering used in most states. The core feature of net metering, common across all jurisdictions that offer the policy, is that it allows participating customers who install DG to receive a credit based on the full volumetric portion of the retail rate for all

[1] See RSA 362-A:1-a(III-a).

electricity that is exported ("fed back") to the grid. The netting mechanism is an accounting process whereby the credit which a customer receives for exported energy is used to offset the purchase of electricity that is supplied to them by the grid. The credit for exports offsets all volumetric rate components associated with electricity supplied from the grid. In this way, a DG customer effectively nets their production and consumption over a billing period, and pays a bill based on the net of the two. In essence, the customer's meter rolls forward when the customer takes service from the grid, and backward when the customer provides a service to the grid by exporting power and running the meter backward. New Hampshire's net metering policy is consistent with this prevailing definition and conception of net metering.

Q8: Why did the Commission initiate this proceeding?

A8: The Commission initiated this proceeding in response to New Hampshire House Bill 1116 ("HB 1116"), which amended several provisions of state law concerning NEM. Specifically, HB 1116 required the Commission is to initiate a proceeding to develop new net metering tariffs and to determine whether and to what extent these new NEM tariffs should be made available within each regulated electric distribution utility's service territory.[2]

Q9: Does HB 1116 set forth the state's goals for the new net metering tariffs?

A9: Yes, it does. The Legislature's stated goals in HB 1116 include continuing to allow reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and to receive fair compensation for this locally-produced power. The Legislature also expressed a goal of ensuring that the benefits and costs of DG are allocated fairly and transparently among all customers. The legislation's overarching goal is to promote a "balanced" energy policy, which is defined as one that supports economic growth and energy

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[2] See RSA 362-A:9, Paragraph XVI.

diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits, a fair allocation of costs and benefits, and a modern and flexible electric grid that provides benefits for all ratepayers.

Q10: In developing these new NEM tariff, what did HB 1116 require the Commission to consider?

A10: The Commission is required to consider the following:

- the costs and benefits of customer-generator facilities;
- how to avoid unjust and unreasonable cost shifting;
- the rate effects of NEM on all customers;
- alternative rate structures, including time based tariffs;
- whether there should be a limitation on the amount of generating capacity eligible for the new NEM tariffs;
- the size of facilities eligible for the new NEM tariffs;
- timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; and
- electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms.[3]

Q11: The first requirement is an examination of the benefits and costs of customer-sited DG facilities. Is this assessment the foundation for the other aspects of NEM that the Commission must consider?

A11: Yes. An accurate assessment of both the benefits and costs of customer-sited DG is necessary in order to determine whether DG causes a level of cost shifting that might be unjust and unreasonable as a result of substantial rate impacts on some or all ratepayers, or whether this growing resource does not cause such unreasonable cost shifts. For example, if the benefits of DG for both participating and non-participating ratepayers exceed the costs to each of these groups, then DG resources will not result in an unreasonable cost shift, and they are unlikely to have adverse rate effects on any customers.

[3] *Ibid.*

The benefit-cost methodology also allows the Commission to assess how the balance of benefits and costs is impacted by changes to the rates and rate structures applicable to NEM customers – for example, whether time-based tariffs or other rate design changes would better balance the benefits and costs of NEM. The relative benefits and costs of net-metered DG also are important in determining whether it is appropriate to limit the size and capacity of customer-sited DG facilities.

Accordingly, this testimony will focus first on assessing the benefits and costs of net-metered solar DG resources for the three regulated utilities – Eversource, Liberty, and Unitil – and then will use the results of that analysis to guide recommendations for the design of new NEM tariffs.

Q12: In your opinion, would new net metering tariffs that are based only on the costs imposed by DG/NEM customers comply with HB 1116?

A12: No. New NEM tariffs that are based solely on cost of service analyses would not comply with HB 1116. The law explicitly calls for new NEM tariffs that consider the benefits as well as the costs of DG facilities installed by NEM customers. The benefits of DG are principally the costs of the energy, generating capacity, and delivery infrastructure that the distribution utility and generation suppliers will not incur as a result of customers installing DG resources, over the life of the DG facilities. There also will be quantifiable environmental benefits, from the costs avoided by not having to mitigate the environmental impacts of the displaced fossil resources, as well as local economic benefits for the state from a thriving DG industry. Many of these benefits will be realized in the long-run, over the 20+ year lifetime of DG resources. New NEM tariffs that do not consider these benefits, and that do not balance costs against these benefits, will not comply with either the letter or the spirit of HB 1116.

III. A BENEFIT-COST METHODOLOGY FOR NET-METERED DG

A. National Context: Toward a Consistent Approach

Q13: Is there a developing consensus on the best practices for designing benefit-cost analyses of behind-the-meter DG resources, including solar photovoltaic (PV) systems, which should inform how the Commission undertakes this analysis?

A13: Yes, there is. It is important to recognize that the issues raised by the growth of demand-side DG are not new. The same issues of impacts on the utilities, on non-participating ratepayers, and on society as a whole arose when state regulators and utilities began to manage electric demand growth through energy efficiency ("EE") and demand response ("DR") programs. To provide a framework for analyzing these issues in a comprehensive fashion, the utility industry developed a set of standard cost-effectiveness tests for demand-side programs.[4] These tests examine the cost-effectiveness of demand-side programs from a variety of perspectives, including from the viewpoints of the program participant, other ratepayers, the utility, and society as a whole.

This framework for evaluating demand-side resources is widely accepted, and state regulators have years of experience overseeing this type of cost-effectiveness analysis, with each state customizing how each test is applied and the weight which policymakers place on the various test results. This suite of cost-effectiveness tests is now being adapted to analyses of NEM and demand-side DG more broadly, as state commissions recognize that evaluating the costs and benefits of all demand-side resources – EE, DR, and DG – using the same cost-

[4] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), hereafter "*SPM*," available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF .

effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner.

Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 1** below. "+" denotes a benefit; "-" a cost.

Table 1: *Demand-side Cost/Benefit Tests*

Perspective (Test)	DG Customer (Participant)	Other Ratepayers (RIM)	Total Resource Cost to Utility or Society (TRC or Societal)
Capital and O&M Costs of the DG Resource	–		–
Customer Bill Savings or Utility Lost Revenues	+	–	
Benefits (Avoided Costs) -- Energy -- Hedging/market mitigation -- Generating Capacity -- T&D, including losses -- Reliability/Resiliency/Risk -- Environmental / RPS		+	+
Federal Tax Benefits	+		+
Program Administration, Interconnection & Integration Costs		–	–

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. HB 1116 required the Commission to assess the rate effects of NEM on <u>all</u> customers, which requires consideration of all of these perspectives.

First, for the customers who install DG, a NEM program will need to pass the Participant test if it is to attract customers by offering a reasonable economic benefit for their participation – thus, DG customers' bill savings and tax benefits must provide a reasonable return given their cost to invest in and to operate a DG system.

Second, the program also should be a net benefit as a resource to the utility system and to society more broadly – thus, the Total Resource Cost (TRC) and Societal Tests compare the costs of the program to its benefits. In the TRC Test, those benefits are principally the costs which the utility can avoid from the reduction in demand for electricity. The Societal Test adds the broader benefits to citizens as whole, for example, economic and environmental benefits that may not be reflected in utility rates.

Finally, the Rate Impact Measure (RIM) test gauges the impact on other, non-participating ratepayers: if the utility's lost revenues and program costs are greater than its avoided cost benefits, then rates may rise for non-participating ratepayers in order to recover those costs. This can present an issue of equity among ratepayers. The RIM test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all parties are likely to benefit from the program. However, it is a test that measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC and Societal tests).

B. Key Attributes of a DG Benefit-Cost Methodology

Q14: Please discuss the key attributes of your recommended methodology to assess the benefits and costs of net metered DG resources.

A14: There are four key attributes:

1. **Analyze the benefits and costs from the multiple perspectives of the key stakeholders.** As discussed above, it is important that the Commission assess the benefits and costs of net metering from the perspectives of each of the major stakeholders – the utility system as a whole, participating NEM

customers, and other ratepayers – so that the regulator can balance all of these important interests. Examining all of these perspectives is critical if public policy is to support customer choice and equitable competition between DG providers and the monopoly utility. In terms of the goals of HB 1116, examining benefits and costs from multiple perspectives is necessary in order to ensure that there are no unreasonable cost shifts and to assess the effects of NEM on <u>all</u> ratepayers, both participants and non-participants.

2. **Consider a comprehensive list of benefits and costs.** The location, diversity, and technologies of DG resources will require the analysis of a broader set of benefits and costs than, for example, traditional QF facilities installed under PURPA. Renewable DG projects produce power in many small (less than 1 MW) installations that are widely distributed across the utility system. The power is produced and consumed either behind the meter or on the distribution system;[5] indeed, each net-metered DG project is generally associated with a load at least as large as the DG project's output,[6] which will limit the amount of power than is exported to the grid. For example, an important attribute of DG is its ability to serve loads without the use of the transmission system. Accordingly, an analysis of DG benefits should consider the avoided costs for reduced lines losses and for deferred transmission and distribution capacity. Renewable DG also will avoid the costs associated with environmental compliance at marginal fossil-fueled power plants. On the cost side, the analysis should consider whether solar or wind DG will result in new costs to integrate these variable resources. A comprehensive examination of benefits and costs is necessary in order to comply with the HB 1116 goal of new NEM tariffs that are fair to both participants and non-participants. The next section of this testimony discusses in more detail the specific benefits and costs that should be considered and that can be quantified.

3. **Analyze the benefits and costs in a long-term, lifecycle time frame.** The benefits and costs of DG should be calculated over a time frame that corresponds to the useful life of a DG system, which, for solar DG, is 20 to 30 years. This treats solar DG on the same basis as other utility resources, both

[5] It is possible that, at high penetrations, DG output to a distribution circuit could exceed the minimum load on the circuit, as has occurred at some locations in Hawaii where, for example, more than 15% of customers on the islands of Oahu and Maui have installed solar. Such penetrations are not expected to be reached in New Hampshire for many years.

[6] Like many states, New Hampshire limits the size of NEM systems, to a maximum of 1,000 kW. In addition, NEM systems must be used to offset the customer's own electricity requirements. *See* New Hampshire Code Of Administrative Rules, Part Puc 902.03.

demand- and supply-side. When a utility assesses the merits of adding a new power plant, or a new EE program, the company will look at the costs to build and operate the plant or the program over its useful life, compared to the costs avoided by not operating or building other resource options. The same time frame should be used to assess the benefits and costs of DG. HB 1116 requires the Commission to assess both the benefits and costs of net-metered DG. The benefits of long-lived DG resources cannot be assessed in a cost-of-service study that focuses (1) only on costs and (2) only on a single test year, because many of the benefits of DG are long-term reductions in infrastructure costs that are not captured in the short time horizon of the cost-of-service studies used for ratemaking.

4. **Focus on NEM exports.** The retail rate credit for power exported to the utility is the essential characteristic of net metering. There would be no need for net metering if no power was exported, and without exports a DG customer appears to the utility grid as simply a retail customer with lower-than-normal consumption. From a legal perspective, PURPA requires the utility to interconnect with the DG customers and to allow the DG customer, at the customer's election, to use its privately-funded generation to serve its own load, on its own private property. It is only when the customer exports power to the utility – power to which the utility takes title at the meter and uses to serve other customers – that the question arises of how to compensate the DG customer for that exported power. This is the essential question that net metering answers, and the focus of the net metering analysis should be determining a credit for NEM exports that is fair to all affected parties.

Q15: Can you provide examples and the experience of other state commissions which have developed benefit-cost analyses of NEM from the three perspectives which you have described?

A15: Yes. **Appendix B** to this testimony discusses the benefit-cost studies of NEM that have been conducted in Nevada, California, and Mississippi. The Nevada example is also instructive in terms of the devastating impact on the DG market in that state when the Public Utilities Commission of Nevada ("PUCN") developed new NEM tariffs based only on a cost of service approach, with only minimal consideration of the long-term benefits of solar DG.

C. The DG Customer as "Prosumer"

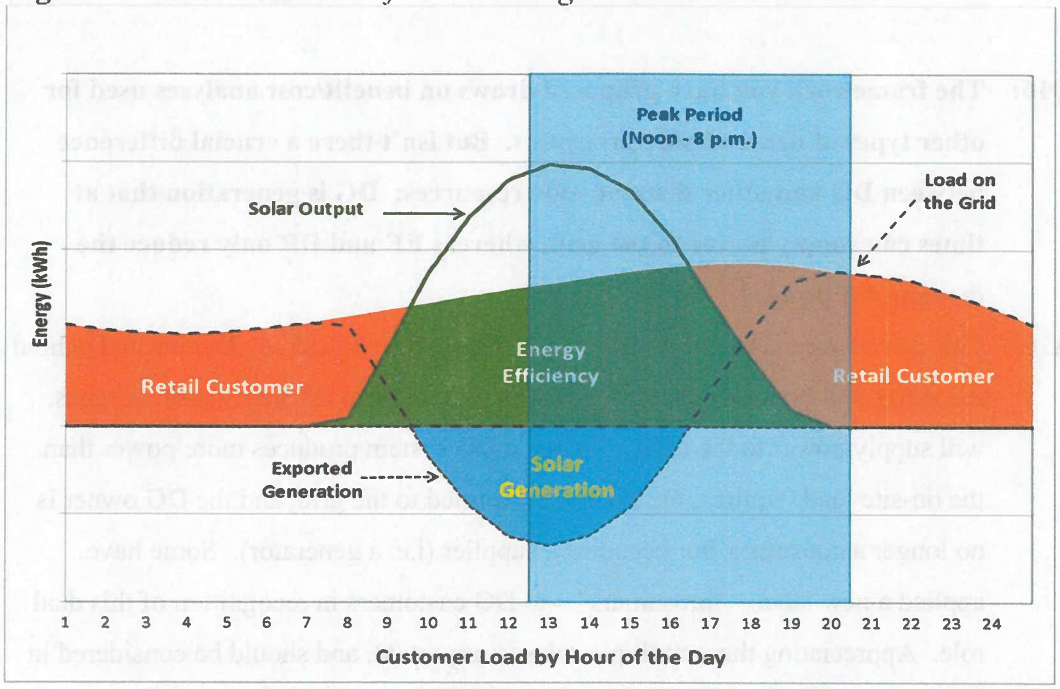
Q16: The framework you have proposed draws on benefit/cost analyses used for other types of demand-side programs. But isn't there a crucial difference between DG and other demand-side resources: DG is generation that at times can supply power to the grid, whereas EE and DR only reduce the demand for power?

A16: This difference exists, is important, and should be considered. DG located behind the meter will both reduce the demand for power from the utility, and, at times, will supply power to the utility. When a DG system produces more power than the on-site load requires, the excess is exported to the grid, and the DG owner is no longer a consumer, but becomes a supplier (i.e. a generator). Some have applied a new label – "prosumers" – to DG customers in recognition of this dual role. Appreciating these multiple roles is important, and should be considered in establishing the framework for evaluating the benefits and costs of DG.

Q17: Please explain these multiple roles in more detail, using the example of a typical residential NEM customer.

A17: To illustrate in detail how net metering works, **Figure 1** shows the three different "states" of a residential net-metered PV system over the course of a day:

Figure 1: *The Three States of Net Metering*



- **The "Retail Customer State."** There is no PV production – for example, at night. At this time, the customer is a regular utility customer, receiving its electricity from the grid. The utility meter rolls forward, and the customer pays the full retail rate for this power.

- **The "Energy Efficiency State."** In this state, the sun is up, and there is some PV production but not enough to serve all of the customer's instantaneous load. The customer is supplied with power from the solar PV system as well as with power from the utility. Onsite solar reduces the customer's load on the utility's system in the same fashion as an energy efficiency measure. None of the solar customer's PV production flows out to the utility grid, the meter continues to roll forward, and the customer will pay the utility the full retail rate for his net usage from the grid during these hours.

- **The "Power Export, or Net Metering, State."** In this state, the sun is high overhead, and PV production exceeds the customer's instantaneous use. The on-site solar power serves the customer's entire load, and excess PV generation flows onto the utility's distribution circuit. The utility meter runs backward, producing a net metering credit for the solar customer. In these hours, the solar customer is no longer just a consumer, but is also a producer of power, i.e. a generator. The net metering credit is the solar customer's compensation for the generation it is supplying to the

> grid. As a matter of physics, the exported power will serve neighboring loads with 100% renewable energy, displacing power that the utility would otherwise generate at a more distant power plant and deliver to that local area over its transmission and distribution system.
>
> This state is the only one in which the customer's generation touches the utility's distribution system or in which a bill credit is produced. In typical PV installations, the solar output exported to the utility is less than half of total PV production, with the exact export percentage depending on (1) the size of the PV system relative to the customer's usage and (2) the hourly profile of the host customer's load. Residential solar customers tend to export a higher percentage of their power output than commercial solar customers.

Q18: What do you conclude from this description?

A18: On-site generation from customer-sited PV that is not exported, i.e., electricity generated in the Energy Efficiency State in Figure 1, does not require net metering. In that case, the customer simply uses his on-site generation to reduce his load, and to the utility the installation of such a DG system appears no different than if the customer had installed a more efficient air conditioner or simply decided to reduce his power usage in the middle of the day. In fact, if the solar customer did not export power to the grid and 100% of the solar output was consumed on-site, there would be no need for NEM.

Thus, the essence of NEM is the ability of a customer with a solar PV system to "run the meter backwards" when the customer has more generation than the on-site load and is serving as a generation source for the utility system. When the meter runs backward, the DG customer receives credit for his generation exports in the form of a retail rate credit from the utility. In the accounting used to calculate the DG customer's bill, the customer can use these credits to offset the cost of usage from the grid when the meter runs forward.

Q19: Does the fact that DG customers can be both consumers and producers of electricity mean that they make more use of the distribution utility's system than regular utility customers?

A19: No. The DG customer either imports power from, or exports power to, the utility's distribution system. When the DG customer imports power from the utility, the customer is using the electricity system (including generation, transmission, and distribution), and the meter runs forward. The customer pays the standard tariff rate for that service. This is no different than how a non-DG customer uses the system.

When the DG customer exports power, it is not the DG customer who is using the distribution system, it is the distribution utility and the DG customer's neighbors, because the title to the exported power transfers to the utility at the solar customer's meter. The utility then uses the exported NEM generation to serve the neighbors' loads. This transaction is no different than when the distribution utility receives power from any other type of generator – the generator is not responsible for and does not have to pay to deliver the power to the utility's other customers. Instead, that delivery service becomes the distribution company's responsibility when it accepts and takes title to the exported power at the generator's meter. The utility is fully compensated for this distribution service when the other customers (including the neighbors) pay the retail rate to have this power delivered to them. Further, the generator is responsible for the incremental costs of interconnecting to the distribution company's system to enable the reliable acceptance and delivery of its exported power, and these costs can be substantial for larger DG installations.

As a matter of fact, the distribution company will save money by using the DG customer's exported power to serve the neighbors, because the utility will avoid the costs of the power generated at a more distant power plant and the costs that the utility would have incurred to deliver the power to that local area over its distribution system. Moreover, the utility will also avoid the future costs of incremental amounts of wholesale generation, regional transmission, and expansions to its own distribution system. The essential public policy issue with net metering is whether these "avoided costs" which the utility saves are less than, equal to, or greater than the sum of (1) the net metering credit that the utility provides to the solar customer and (2) the utility's integration and program costs.

Q20: Do DG customers cause the local utility to incur distribution costs which the DG customers are not paying?

A20: No. The fact that DG customers export power to the grid does not mean that they should pay for the costs which the distribution utility incurs to deliver that power, beyond the interconnection costs required for the utility to accept those exports. The "two-way" power flows which they may create do not necessarily increase utility costs, particularly at today's penetration of DG, and can reduce the utility's distribution system costs by making more capacity available on the upstream portions of the distribution system. As the penetration of DG increases – particularly if it reaches levels such as those now seen in Hawaii – further analysis may be needed to determine whether and by how much more two-way power flows increase utility costs. However, at today's penetration of DG in New Hampshire, DG customers are not causing the utilities to incur costs which the Company is not collecting from those customers.

Q21: If a NEM customer ends up with a small, zero, or even negative bill at the end of a month, does this mean that the NEM customer is not paying for the utility service the customer is receiving?

A21: Absolutely not. First, whenever the solar customer uses the utility system (by importing power and rolling the meter forward), the solar customer pays fully for the use of the utility system, at the same rate as any other customer. If the solar customer ends the month with a small, zero, or even a net credit bill from the utility, this is the result of crediting the customer for the value of the power which the customer supplies to the utility (from exporting power and running the meter backwards). In some months, these credits can more than offset the solar customer's costs of utility service when the customer imports power and the meter runs forward. However, these credits are not the result of the solar customer's use of the utility system; instead, they are the means to account for the service which the DG customer has provided <u>to</u> the utility, in the form of exported generation provided to the utility at the meter. Thus, the solar customer has paid fully for all actual use which that customer has made of the utility system, even though the customer's net bill at the end of the year may be small, zero, or even a net credit. There is the public policy issue of whether the bill credits for exported power at the retail rate are the right credit for those exports – and this case should focus on that issue – but this does not change the fact that the solar customer has paid fully for his or her actual use of the utility system.

Q22: Doesn't the DG customer require the presence of the grid for his solar system to operate and to produce power?

A22: Yes, of course. But this is no different than any electric customer who cannot receive service from the utility unless they are interconnected to the grid. The difference is that the DG customer is also in a position <u>to provide a service to the utility</u> as a result of the customer's installation of onsite generation.

Q23: Does the utility incur costs to "stand by" to serve a solar customer when the solar customer is exporting power to the grid?

A23: No. The costs which the utility incurs to serve a solar customer are no different than those it incurs to stand by to serve a regular utility customer whose usage for periods may be very low – for example, in the middle of the day when the occupants of a house are away at work and school – but who may suddenly impose a load on the system. As a consumer, a solar customer looks like a standard customer who uses power in the morning, evening, and at night, but who turns everything off in the middle of the day, as illustrated by the dashed "Load on the Grid" line in Figure 1. Such a customer may come home unexpectedly in the middle of the day, turn on the air conditioner and run an appliance, and produce a sudden spike in usage. But these load fluctuations are something the utility is well-prepared to serve on an aggregate basis, and the costs of such normal "stand by" service are included in the utility's regular rates.

Similarly, a solar customer may suddenly impose a demand on the system if a cloud temporarily covers the sun in the middle of the day. Again, however, this variability is manageable due to the small sizes and geographic diversity of solar DG systems – for example, at the time one PV system is being shaded, another will be coming back into full sunlight.

It is possible that, as solar penetration increases, the aggregate variability of all solar customers' electric output may add to the variability of the power demand that the utility must serve, and impose additional costs for regulation and operating reserves on the system operator. The costs of meeting this added variability is one of the factors considered in the studies that estimate integration costs for solar resources. Such studies in other states have shown that integration costs are low at the current level of solar DG penetration.[7]
NEM service is also distinguishable from the standby service that the utility provides to large industrial customers who have their own on-site generation, such as combined heat and power ("CHP") units. These large customers typically are served with dedicated transmission or distribution circuits that may be used fully only sporadically, when the customer's CHP unit is down. As a result, there is some logic in assessing a demand or reservation charge to cover the costs of these dedicated facilities that are necessary to provide backup service. In contrast, the diversity of loads on distribution circuits serving smaller NEM customers, plus the facts that NEM systems will not all fail at once and their penetrations today

7 For example, see the Black & Veatch solar integration study for Arizona Public Service, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012). Also, *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas* (Battelle Northwest National Laboratory, March 2014); hereafter the "Duke Integration Study." The Duke Integration Study calculates that, with 673 MW of PV capacity on the Duke utility systems in 2014, integration costs are about $0.0015 per kWh. See Table 2.5 and Figure 2.51.

are low, allows the utility to provide service to NEM customers without significant changes or added costs on the existing distribution system.

Q24: Doesn't the utility incur costs to store the excess kWh produced by NEM systems, allowing the NEM customer to "bank" kWh which the customer uses later when the meter is rolling forward?

A24: No. Net metering does not involve the storage of electricity, or of energy in any form. This idea is one of the common myths of net metering. Again, the NEM customer is both a consumer and generator of electricity. When the NEM customer is a generator, exporting power in excess of the onsite load, as a matter of physics that generation is immediately consumed by nearby customers. In no way is the power stored for later use. When the solar customer later consumes power from the grid – for example, after the sun sets – the power used is generated and transmitted by the utility at that later time. The fact that NEM credits from exports are used to offset the costs of subsequent usage simply represents an accounting transaction – offsetting a credit with a debit on the customer's account by changing the direction that the meter is recording; it does not represent any actual use of the grid to "store" or "bank" electrons or energy. The utility does not incur any costs to "store" electrons for the NEM customer.

D. PURPA Matters

Q25: Please discuss the implications for evaluating NEM of the fact that most DG customers are "qualifying facilities" (QFs) under the Public Utilities Regulatory Policies Act of 1978 (PURPA).

A25: As generators, renewable DG customers typically have legal status as QFs under PURPA. As a result, the serving utility is required under this federal law to do the following:

- to interconnect with a customer's renewable DG system,

- to allow a DG customer to use the output of his system to offset his on-site load, and

- to purchase the excess power exported from such systems at a state-regulated price that is based on the utility's avoided costs.[8]

These provisions of federal law are independent of whether a state has adopted NEM; thus, the adoption of NEM only impacts the accounting credits which the customer-generator receives for power exports to the grid, and the analysis of the economics of NEM should focus on those exports.

An important implication of the focus on exports is that, even if it is found that there is a "cost shift" from solar DG customers to non-participating ratepayers, any calculation of such a cost shift should only consider the power exported by DG customers, not the DG output that a customer uses on-site, behind the meter, without the power ever touching the grid. As noted above, DG exports are typically a minority, typically 30% to 50%, of DG production. There are always cost shifts when a customer reduces the demand placed on the grid, or shifts load to a different time period, as the result of many types of actions that utilities and regulators encourage – energy efficiency, demand response, or using DG to serve your own load. Such actions by DG customers should not be singled out, penalized, or treated differently than other steps that consumers take to manage their energy demand and reduce their utility bills.

Q26: Does PURPA also impact the rates for the sale of power from an electric utility to DG customers?

A26: Yes. As QFs, DG customers also are governed by the FERC's rules concerning the sale of power from utilities to QFs. These rules specify that QFs have the right to purchase power at rates which are just and reasonable, that do not discriminate against QFs in comparison to the utility's other retail rates, and that

8 The PURPA requirements can be found in 18 CFR §292.303.

are based on accurate data and consistent system-wide costing principles.[9] Significantly, the FERC rules create a "safe harbor" for the utility against claims of discrimination if its QFs pay the same rates as similar customers:

> Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

IV. SPECIFIC QUANTIFIABLE BENEFITS AND COSTS

Q27: Please list and provide comments on the specific benefits and costs that should be quantified in the net metering methodology.

A27: There are several literature reviews or meta-studies which have reviewed the existing NEM/DG benefit/cost studies and have summarized the benefits and costs included in this growing literature:

- A 2013 literature review from the Vermont Commission.[10]
- The Rocky Mountain Institute's (RMI) 2013 meta-analysis of solar DG benefit and cost studies.[11]
- The New York State Energy Research and Development Authority (NYSERDA) has conducted a literature review of NEM benefit/cost studies, with assistance from Energy and Environmental Economics, in preparation for a NEM study in New York.[12]

Based on this literature, several recent studies have formulated recommended approaches to conducting such analyses, including the specific benefits and costs

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[9] 18 CFR §292.305(a) and (b). Also see "What are the benefits of QF status?" on the FERC website: http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp.

[10] This literature review, as well as the report and analysis of net metering that the Vermont Commission completed, are available at http://publicservice.vermont.gov/topics/renewable_energy/net_metering .

[11] Rocky Mountain Institute (RMI), "A Review of Solar PV Benefit and Cost Studies" (July 2013), available at http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

[12] See the November 10, 2014 NYSERDA presentation listed at http://ny-sun.ny.gov/About/Stakeholder-Meetings.aspx .

that should be considered.[13] These lists of benefits and costs are also consistent with the list of proposed costs and benefits of net metering systems that the New Hampshire Sustainable Energy Association ("NHSEA") provided in the technical workshops, and that is included as **Appendix C**. In addition, other "value of solar" studies, such as a March 2015 study commissioned by the Maine Public Utilities Commission (the "Maine Study"),[14] have focused on one side of the benefit-cost equation – the long-term benefits of distributed solar generation. Finally, cost effectiveness analyses of other types of demand-side programs also draw upon the same categories of benefits and costs, recognizing that DG introduces a new category of integration costs for the power exported to the grid.

Based on the above sources and our prior experience with such studies, **Tables 2 and 3** list the specific benefits and costs, respectively, that should be quantified in the Commission's net metering methodology, along with comments on the methodology for the quantification of each specific category.

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[13] Interstate Renewable Energy Council and Rabago Energy, *A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation* (October 2013) and Synapse Energy Economics, *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits* (prepared for the Advanced Energy Economy Institute, September 2014).

[14] Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015), hereafter "Maine VOS Study." Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

Table 2: *Avoided Cost Benefits (for TRC, Societal, and RIM Tests)*

NEM Benefit Category	Description	Comments on Methodology
Avoided Energy	Change in the variable costs of the marginal system resource, including fuel use and variable O&M, associated with the adoption of DG.	Typically calculated from market energy prices (in deregulated markets), from production cost analyses (for regulated monopoly utilities), or from the energy costs of the proxy marginal resource. Calculation should be granular enough to calculate avoided energy costs of DG resources accurately. These energy costs should be adjusted for the appropriate energy losses (see below).
Avoided Generating Capacity	Change in the fixed costs of building and maintaining new conventional generation resources associated with the adoption of DG.	Forecast of marginal generation capacity costs calculated from market capacity prices (in deregulated markets), from the cost of the least expensive new capacity resource – typically a new combustion turbine peaker (for regulated monopoly utilities), or from the capacity cost of the proxy marginal resource. These capacity costs should be based on public, transparent data, should be adjusted for the appropriate losses (see below) and the applicable capacity reserve margin, and should reflect the capacity contribution of each type of renewable DG resource.
Avoided Line Losses	Change in electricity losses from the points of generation to the points of delivery associated with the adoption of DG.	Applies to both energy and generating capacity. Should be based on marginal line loss data and DG generation profiles.
Avoided Ancillary Services	Change in the costs of services like operating reserves, voltage control, and frequency regulation needed for grid stability associated with the adoption of DG.	These costs can be avoided if such reserves are procured based on loads that DG will reduce. Future DG technologies like "smart inverters" may provide services such as voltage support.
Avoided T&D Capacity	Change in costs associated with expanding/replacing/upgrading T&D capacity associated with the adoption of DG.	Based on marginal capacity costs to expand/replace/upgrade capacity on a utility's T&D system. Contribution of a DG resource to avoiding transmission or distribution capacity will depend on the contribution of DG to reducing peak loads on the transmission or distribution systems. This analysis will become more complex as one moves to lower voltages on the distribution system, where distribution substations and feeders will peak at different times.
Avoided Environmental Costs	Change in costs associated with mitigation of SO_x, NO_x, and PM-2.5 emissions or with waste disposal costs (e.g. coal ash) due to the change in production from each IOU's marginal generating resources as a result of the adoption of DG generation.	Can be included in the Avoided Energy component.
Avoided Carbon Emissions	Change in costs to mitigate CO_2 or equivalent emissions due to the change in production from each IOU's marginal generating resources associated with the adoption of DG.	Based on estimates of the value of carbon emission reductions from utility integrated resource plans (IRPs) or from regulatory agencies with jurisdiction over such emissions. Such reductions can have quantifiable value to ratepayers through avoiding direct

		emission costs (as in cap & trade markets) or through the costs of resource choices intended to reduce carbon emissions (such as the replacement of coal with natural gas.
Fuel Hedging / Fuel Price Uncertainty	Costs to lock in the future price of fuel to match the fixed-price attribute of renewable DG.	Can be approximated through the use of forward natural gas prices to forecast future avoided energy costs, plus the costs avoided by not having to engage in such hedging.
Market Price Mitigation	Reduction in energy and capacity wholesale market prices as a result of lower demand resulting from DG adoption.	This benefit of lower market prices as a result of new demand-side resources has been quantified in New England as demand reduction-induced price elasticity (DRIPE).
Avoided Renewables	Reduction in above-market generation costs associated with the utility's acquisition of renewable resources, if DG will contribute to meeting the utility's renewable procurement goals.	This benefit will apply to the extent that renewable DG meets a state goal that otherwise would be met with utility-owned or contracted resources.
Societal Benefits (for the Societal Test)	Benefits for citizens of the utility's service territory or state that are not reflected directly in customer's energy costs.	Lower environmental costs from… • Damages due to climate change • Consumption or withdrawal of scarce water resources • Land use impacts Health benefits from…. • Lower criteria air emissions Economic benefits from… • Fewer power outages • Greater local economic activity

Table 3: *Costs of DG Programs (for TRC and RIM Tests)*

NEM Cost Category	Description	Comments on Methodology
For TRC Test…		
DG Resource	Capital and O&M costs of the DG resource.	
Integration	Increased costs for regulation and operating reserves to integrate variable renewable DG resources.	Integration costs should be those attributable to DG that are incremental to the costs to meet load variability.
Administrative / Interconnection	Utility costs to administer the NEM/DG program, as well as utility costs to interconnect DG resources that are not paid by the DG customer.	Should include the incremental costs associated with net metering above those required for regular billing, as well as other administrative costs. Interconnection costs should not include such costs if they are paid by the DG customer itself.
For RIM Test…		
Lost Revenues	Bill credits provided to NEM customers for exported energy.	Will vary depending on the tariff under which the DG customer takes service.
Integration	Same as above	
Administrative/ Interconnection	Same as above	

Q28: Do you have any general observations on these specific categories of benefits and costs?

A28: Yes. First, all of the above categories of benefits and costs are quantifiable, and have been quantified in other NEM or DG benefit/cost studies.

Second, the quantification of these benefits may require data and/or calculations that the utilities may not produce today in the normal course of business. For example, not all utilities calculate marginal line losses or marginal T&D capacity costs (although some do), and there are well-accepted techniques to perform these calculations.

Third, to the extent that studies of relatively complex issues – such as solar or wind integration costs – have yet to be performed, reasonable values for these costs can be derived from such studies performed for other utilities.

Fourth, some states (including New Hampshire) still offer modest state incentives for new solar DG. We have not included these incentives as a ratepayer cost of NEM in our analysis, under the assumption that these incentives have been intended to develop and transform the solar market in New Hampshire, and will phase out over time as solar costs decline and the market matures. These incentives also can be justified by the significantly greater societal benefits of this clean energy development.

Finally, if there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that category. For example, the EPA's proposed regulations of greenhouse gas (GHG) emissions from power plants under Section 111(d) of the Clean Air Act indicate that the federal government may regulate such emissions based on the administration's social cost of carbon (SCC) values. The EPA's actions increase the certainty that the utilities will incur significant future costs for reducing carbon emissions.

Accordingly, a reasonable assumption for future carbon costs is not zero, but should consider a range of possible future mitigation costs.

Q29: Two of the New Hampshire utilities – Liberty and Unitil – are distribution companies without their own generation or bulk transmission assets. Should the Commission limit the assessment of the benefits and costs of NEM for these smaller utilities only to the delivery services which they provide?

A29: No. These utilities do not provide only distribution services; they also offer default energy service that provides generation and they bill customers for the regional transmission required to supply their service territories and to provide market access. They are required to offer their customers a fully bundled retail product which includes both delivery services and generation at the default energy service rate. Customers who install net metered DG are providing an alternative to retail electric service that includes both generation and the delivery of the power directly to load. Accordingly, the benefits and costs of NEM should include all of the components of this service – generation, transmission, and distribution. When a customer installs DG, the serving distribution utility avoids the need to purchase generation in the market and reduces its use of the regional transmission grid to import power, as well as potentially avoiding its own costs for local delivery of the power that the DG customer is now supplying. In the transparent, deregulated wholesale market in New England, the avoided costs for generation and bulk transmission can be readily estimated, even though the distribution company does not own or control any of the upstream assets.

V. NEW BENEFIT-COST STUDIES FOR THE NEW HAMPSHIRE UTILITIES

Q30: Have you performed new benefit-cost studies of solar DG for the New Hampshire utilities?

A30: Yes, I have. **Appendix D** to this testimony includes a new study reporting the results of applying the full set of *SPM* cost-effectiveness tests to solar DG on the Eversource, Liberty, and Unitil systems. These benefit-cost analyses follow the general approach discussed above, including the use of multiple perspectives, a comprehensive list of benefits and costs, and a long-term analysis that focuses on generation exports.

Q31: Please summarize the results of these studies.

A31: The following three **Tables 4, 5, and 6** present the results of the benefit and cost analyses and the resulting *SPM* tests for the residential, commercial, and combined residential and commercial markets of the three utilities. The results are also illustrated in **Figures ES-2 and ES-3** for Eversource. **Appendix D** provides a full discussion of the calculations of the benefits and costs that were used for these tests. In evaluating these results, it is important to acknowledge that there is uncertainty in these benefit and cost estimates, and thus, as with any such set of cost-effectiveness tests, a reviewer should not place undue weight on whether the score on a particular test is a few percent above or below 1.0. Instead, the goal should be to have *SPM* scores on all of the tests that are in a similar range close to 1.0 (or higher), which indicates that NEM has achieved a reasonable, equitable balance of benefits and costs for all concerned – solar customers, other ratepayers, and the utility system as a whole.

Table 4: *SPM Test Results: Residential*

Cost or SPM Test	Utilities		
	Eversource	**Liberty**	**Unitil**
Residential	*53%*	*74%*	*73%*
Costs *(25-year levelized cents/kWh)*			
A1. Direct Avoided Cost Benefits	20.6	20.0	19.6
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	17.6	18.3	16.3
C. Bill Savings / Lost Revenues	20.1	19.2	19.5
SPM Test Results			
TRC – A1 ÷ B	**1.17**	**1.09**	**1.20**
Societal – A2 ÷ B	**1.73**	**1.63**	**1.80**
Participant – C ÷ B	**1.14**	**1.05**	**1.19**
RIM – A1 ÷ C	**1.03**	**1.04**	**1.01**

Table 5: *SPM Test Results: Commercial*

Cost or SPM Test	Utilities		
	Eversource	**Liberty**	**Unitil**
Commercial	*47%*	*26%*	*27%*
Costs *(25-year levelized cents/kWh)*			
A1. Avoided Cost Benefits	20.6	20.0	19.6
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	14.6	14.9	14.0
C. Bill Savings / Lost Revenues	15.1	14.0	15.7
SPM Test Results			
TRC – A1 ÷ B	**1.41**	**1.34**	**1.40**
Societal – A2 ÷ B	**2.08**	**2.00**	**2.09**
Participant – C ÷ B	**1.03**	*0.94*	**1.12**
RIM – A1 ÷ C	**1.37**	**1.42**	**1.25**

Table 6: *SPM Test Results: Residential and Commercial*

Cost or SPM Test	Utilities		
	Eversource	Liberty	Unitil
Residential & Commercial	*100%*	*100%*	*100%*
Costs *(25-year levelized cents/kWh)*			
A1. Avoided Cost Benefits	20.6	20.0	19.6
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	16.2	17.4	15.7
C. Bill Savings / Lost Revenues	17.7	17.9	18.4
SPM Test Results			
TRC – A1 ÷ B	**1.27**	**1.15**	**1.25**
Societal – A2 ÷ B	**1.88**	**1.71**	**1.87**
Participant – C ÷ B	**1.10**	**1.03**	**1.17**
RIM – A1 ÷ C	**1.16**	**1.12**	**1.06**

Q32: What are key conclusions that you draw from these results?

A32: The principal conclusions of our analysis are as follows:

1. **Solar DG is a cost-effective resource** in New Hampshire, as the benefits equal or exceed the costs in the Total Resource Cost and Societal Tests.

2. There is a **balance between the costs and benefits of residential DG** for both participants and non-participants, as shown by the results close to or above a benefit-cost ratio of 1.0 for the Participant and RIM tests.

3. **Significant rate design changes for residential DG customers**, such as requiring solar DG customers to take service under rates with demand charges that would be difficult for solar customers to avoid, would upset this balance. As an example of this from the commercial market, the low Participant test score for Liberty's commercial market is due to the demand charge in the G-1 commercial rate.

4. The **benefits of DG significantly exceed the costs in the commercial market**. Encouraging growth in this market would help to ensure that DG resources as a whole provide net benefits to the utilities as a whole. Removing or reducing any rate design barriers such as demand charges would be one way to assist the commercial solar market in New Hampshire.

VI. APPLICATION OF THE BENEFIT-COST METHODOLOGY TO SET RATES

A. Net Metering Benefit – Cost Analyses and Rate Design

Q33: How should the analysis which you have outlined above be used to determine the rates and charges which will apply to NEM customers?

A33: Any significant new charge or major change in rate design applicable to net-metered customers should be tested to ensure that, after it is applied, DG will remain a viable economic proposition for participating ratepayers, the utility system, and the state as a whole, while not imposing undue upward pressure on the rates of non-participants. Such a balancing test should use a long-term benefit-cost analysis from multiple perspectives, because DG is an important long-term resource whose economics should be assessed over its full economic life, in the same way that other resource options are assessed.

Q34: Are there important lessons from other states in terms of how the results of a cost-benefit analysis of NEM may differ among different types and classes of customers?

A34: Yes. The impacts of net metering on non-participating ratepayers will vary significantly across customer classes. For example, the costs of NEM are typically lower for commercial and industrial (C&I) classes than for residential customers, for several reasons. First, C&I rates tend to be lower than residential rates. Second, the solar DG systems of C&I customers export less power to the grid than residential systems, because the diurnal load profile of C&I customers often is a better match for the profile of solar output and because the DG systems installed by C&I customers typically are smaller relative to the size of the on-site load. Finally, rate design has a major impact on the bill savings that NEM customers can realize, and thus on the lost revenues that are the major cost of NEM for non-participating ratepayers. C&I rate designs often recover a portion of the utility's costs through monthly customer and demand charges that are difficult for C&I customers to avoid. Cost studies adopted by the California PUC have demonstrated that demand charge structures overcharge solar customers relative to the costs that they impose on the system, and undervalue the peaking capacity that solar DG provides. As a result, SCE and other California utilities have designed rate options with reduced demand charges but correspondingly higher volumetric time-of-use rates, and they make those rate options available to C&I customers who install solar.[15]

B. Demand Charges Are Problematic for Small DG Customers

Q35: Are rate designs with demand charges appropriate for residential and small commercial customers who install DG?

A35: No, for several reasons.

First, demand charge-based rates are not cost-based for customers who install solar. Customers who install solar DG systems serve a significant portion of their load with their own on-site generation. This reduces the utility's costs to serve the DG customers and provides new renewable capacity to the grid. However, if a significant portion of the utility's costs are collected through a demand charge, the DG customers may see little reduction in their bills for the costs covered by the demand charge. This relatively small change in their bills may fail to compensate them for the capacity-related costs that their on-site generation avoids. For example, a cloudy, low-demand day with low PV output may be the day that causes solar customers to incur a significant demand charge for the entire month. However, the resulting monthly bill will fail to recognize that the same customer contributed significant peaking capacity on the hot, sunny, high demand

[15] See California PUC Decision No. 14-12-080, adopting Option R rates for PG&E after a fully-litigated proceeding; Decision No. 13-03-031 (March 21, 2013), at p. 31, discussing Option R rates for Medium and Large Power customers; and CPUC Decision No. 09-08-028 (August 20, 2009), at p. 22, first implementing Option R rates for SCE's Medium and Large Power customers who install solar.

days of that same month, and thus the utility avoided significant capacity-related costs which are not recognized in the solar customer's bills.

Second, demand charges present serious problems with customer acceptance, as shown by several market research studies on small customers' rate design preferences:

- In 2013 the three major investor-owned electric utilities in California commissioned a customer survey as part of the CPUC's comprehensive rulemaking proceeding on residential rate design.[16] This study concluded that a demand charge "was confusing" to participants, who ended up making inaccurate comparisons to a fixed monthly service fee because they failed to comprehend that a demand charge "varies based on kW demand levels."[17]

- In 2015, San Diego Gas & Electric (SDG&E) conducted a survey of customer preferences for a new net metering (NEM 2.0) tariff in California. This survey only looked at possible new structures for the NEM 2.0 tariff, and did not include a continuation of the existing NEM 1.0 tariff based on a retail rate credit using the existing volumetric rate structure. The possible new NEM 2.0 structures that SDG&E tested included (1) a feed-in tariff with a set price for all DG output, (2) a demand charge, and (3) an installed capacity charge based on the installed kW of DG capacity. Significantly, the simplest structure, the feed-in tariff, although not as simple as the existing NEM 1.0, was favored over demand charges or installed capacity charges by wide margins – by 4-to-1 over a demand charge and by 5-to-1 over an installed capacity charge. The survey concluded that, for customers, the key drawbacks of the

[16] CPUC Docket R. 12-06-013.
[17] Hiner & Partners, Inc. *"RROIR" Customer Survey*, at 22 (April 16, 2013).

demand charge are that it is "confusing," "unpredictable (may pay more)," and "can be difficult to change behavior" to reduce your maximum 15-minute demand.[18] One of the respondents to the SDG&E survey summarized the problematic behavioral economics associated with extending demand charges to residential customers:

> I don't like anything about it. I will constantly have to monitor how many electric appliances are being used at each time, and will have to become the "electricity police" in my household and make sure that each family member is complying.[19]

In January 2016, the CPUC found that the utility proposals to levy demand charges or installed capacity fees on DG customers would face difficulties with customer acceptance, were not cost-based, and would be contrary to the CPUC's rate design goals that focus on implementing time-of-use ("TOU") rates.[20]

- Public Service of Colorado (PSCo) recently conducted a focus group to gauge customers' responses to new residential rate designs, including one with a demand charge that would apply only during the on-peak TOU period. The customers' response indicated that the combination of a demand charge and a specific time-of-use period in which it applies is potentially confusing to customers and challenging for customers to manage.[21]

Q36: Are there other practical issues with rate designs featuring demand charges?

A36: Yes. Demand charges substantially complicate customers' and vendors' ability to analyze and project the bill savings from demand-side programs, including energy

[18] Hiner & Partners, *Final Report: Solar (NEM) Rate Preferences Survey Results*, at Slide 8 (June 2015).
[19] *Id.*, at Slide 24.
[20] *See* CPUC Decision No. 16-01-044, at 76-79, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K285/158285436.pdf.
[21] Colorado PUC Docket No. 16AL-0048E, Testimony of PSCo witness Alice K. Jackson, Exhibit AKJ-1, at p. 25 of 30.

efficiency, demand response, and DG. For example, demand data for typical home energy uses and appliances is not readily available. Furthermore, understanding and accepting demand charges will require customers to become familiar with data on their 15-minute demands. Obviously, this data will not even become available to customers until an advanced metering infrastructure is installed. Even then, customers will have to analyze and understand much more data on their energy use to appreciate when their demand peaks and what the hourly profile of their usage is.

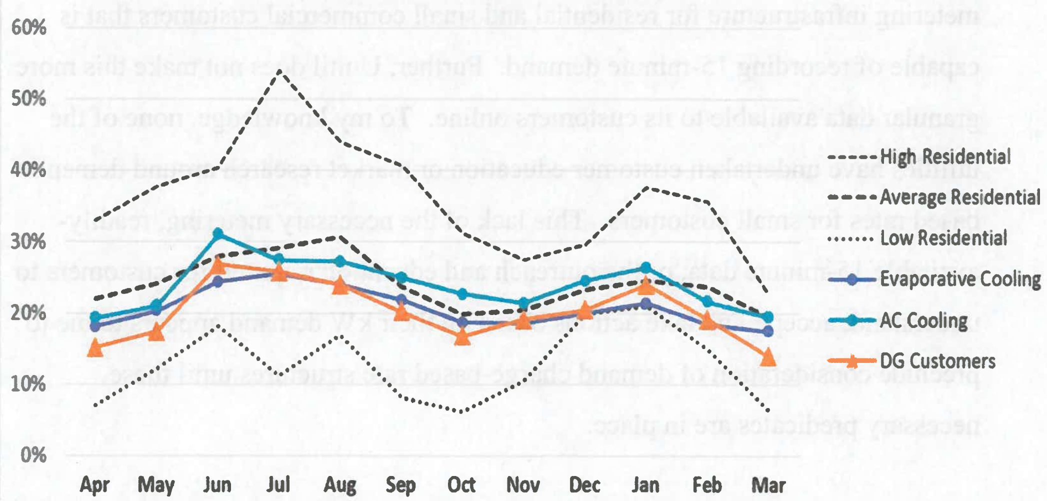
In New Hampshire, it is my understanding that only Unitil has an advanced metering infrastructure for residential and small commercial customers that is capable of recording 15-minute demand. Further, Unitil does not make this more granular data available to its customers online. To my knowledge, none of the utilities have undertaken customer education or market research around demand-based rates for small customers. This lack of the necessary metering, readily-available 15-minute data, or the outreach and education required for customers to understand, accept, and take actions based on their kW demand appears to me to preclude consideration of demand charge-based rate structures until these necessary predicates are in place.

C. Separate Rate Classes for DG Customers

Q37: Should customer-generators be placed into their own rate classes?

A37: No, a separate customer class should not be created simply as a function of installing DG. Customer-generators should not be placed into a separate class without sufficient data to justify distinct treatment from the customer class in which a customer took service before installing DG. It cannot be assumed that, after installing DG, customers will become significantly different than other customers in the class. For example, data from many states show that adding solar tends to change a larger-than-average residential customer into a smaller-than-average one, but both pre-and post-solar customers are well within the range of sizes typical of the residential class.[22] As one example, the following chart shows the average monthly load factors for residential customers on the El Paso Electric ("EPE") system, including customers with solar DG as well as standard customers both with evaporative cooling and with air conditioning.[23] As **Figure 2** shows, the load factors of solar customers are similar to those of customers with evaporative cooling, and well within the range for the residential class as a whole. In a recent settlement of its general rate case, EPE withdrew its proposal to create a separate class for DG customers.[24]

Figure 2: Residential Load Factors



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[22] In 2014, the Colorado PUC held workshops on net metering issues. Data from those workshops showed that the typical residential customer in Colorado who installs solar tends to have greater usage than an average customer, with an average monthly pre-solar bill of $126 compared to the average residential bill of $77 per month. After adding solar, the typical solar customer's bill drops to $50 per month. This information is based on data from solar customers on the Public Service of Colorado system. See "On-Site Solar Industry Answer to Questions set forth in Attachment A of Commission Decision No. C14-0776-I," filed July 21, 2014 in Colorado PUC Docket No. 14M-0235E, at pp. 8-9.

In 2014, the Utah Public Service Commission reached a similar conclusion in rejecting a proposal from Rocky Mountain Power to impose a net metering facilities charge. In Utah, the typical residential customer uses 500-600 kWh per month, with net metered customers falling at the low end of this range at 518 kWh per month. The Utah commission concluded that "[t]hese facts undermine PacifiCorp's reasoning that net metered customers shift distribution costs to other residential customers in a fashion that warrants distinct rate treatment." See Utah PSC, Order issued August 29, 2014 in Docket No. 13-035-184, at p. 62.

[23] Texas Public Utilities Commission Docket No. 44941, EPE response to Solar Energy Industries Association Data Requests (DR) 1-13 and 1-24.

[24] See Texas PUC Order dated August 25, 2016 in Docket No. 44941.

Q38: What are the implications under PURPA of creating separate classes for DG customers?

A38: As noted above, the FERC rules implementing PURPA create a safe harbor against claims of discrimination if DG/QF customers pay the same rates as similar non-DG customers. Creating a separate DG/QF customer class with rates that are different than those applicable to other similar customers moves out of this safe harbor. For example, if a utility does not require other types of QFs (such as combined heat & power facilities) to take service under a distinct customer class to which costs are allocated separately from similar customers who are not QFs, then a separate customer class for residential consumers who install DG would be inconsistent with the treatment of other partial requirements customers who are QFs, and thus would violate this FERC rule.

D. Rate Design Changes to Adjust the NEM Benefit-Cost Balance

Q39: If the Commission's analysis finds that there is a cost shift from customer-generators to non-participating ratepayers that is large enough to require mitigation, what are the recommended rate design approaches to remedying this problem?

A39: There are several. Impacts on non-participants are most likely to be a concern in the residential market, because residential solar systems export a higher percentage of their output and because most of the residential cost of service is recovered through volumetric rates. The preferred rate design solutions are the following:

- Encourage increased adoption of **time-of-use rates** that align rates more closely to the changes in the utility's costs over the course of a day.[25]

[25] This can include on-peak volumetric rates that recover capacity-related costs. Residential TOU rates should be kept simple and promoted through outreach and education programs, to ensure customer acceptance. Residential demand charges should be avoided due to their complexity, lack of time sensitivity, and unfamiliarity for residential customers. California has mandated that, once the state's 5% NEM cap is reached, succeeding NEM customers must elect a TOU rates.

- Adopt a monthly **minimum bill** to recover customer-related costs, thus ensuring that all customers make a minimum contribution to the costs of the utility infrastructure that serves them.

- Remove **public benefit charges and the electricity consumption tax** from the NEM export rate, so that all customers contribute to these public purpose programs on the equitable basis of the power they take from the utility system.[26]

Q40: Why are these rate design changes the preferable way to address balance of benefits and costs in NEM?

A40: These solutions are preferable for the following reasons:

- **Address the central equity issue.** Minimum bills, for example, ensure that all customers make a minimum contribution to the utility infrastructure that serves them. The minimum bill can be set to cover the utility's customer-related costs (for metering, billing, and customer account services) which clearly do not vary with the use of either energy or capacity. In this way, they address directly the issue of equity between participating and non-participating ratepayers by ensuring that all customers contribute equally to cover such costs. Similarly, it is equitable for all customers to contribute to public purpose programs in the same way, based on amount of service which they take from the utility system.

- **Consistent with cost causation.** TOU rates align rates more closely with the utility's underlying costs than do flat rates or rates tiered by usage. A minimum bill can be set to assure recovery from all customers of customer-related costs which do not vary with usage. Thus, both TOU rates and minimum bills are consistent with cost causation principles.

- **Encourages customer choice.** Because a minimum bill only imposes a floor on the customer's bill and does not apply if usage remains above the minimum bill level, it provides the greatest scope for customers to impact their energy bills by exercising their choice to participate in self-generation, energy efficiency, or demand response. Similarly, TOU rates send more accurate price signals to customers concerning both the value of their DG output and when it is best to either consume or conserve energy.

- **Customer acceptance.** California, which has the nation's largest distributed solar market, has adopted a $10 per month residential minimum bill for the large electric utilities in that state, and the minimum

[26] California and Nevada have implemented this modification to NEM export rates.

bill was recently increased in Hawaii, where solar penetration is far higher than any other state. In contrast, attempts to implement monthly fixed charges on solar customers have not been well-received in other states, and have been perceived as efforts to tax solar production such that it would no longer be economic.[27] In essence, minimum bills are perceived as a fair balance between allowing customer choice and ensuring that all customers make an equitable contribution to the costs of utility infrastructure. Significantly, although California and Nevada recently issued very different decisions on net metering, both commissions rejected proposals to apply demand charges to residential solar customers due to concerns with customer acceptance.[28]

- **Non-discrimination.** Many states, including New Hampshire, have statutory prohibitions against undue discrimination in the design of utility rates.[29] If fixed charges are raised for all residential customers, there can be adverse bill impacts on all low-usage customers, including low-income ratepayers. A minimum bill is more likely to avoid such problems, as it will apply to a relatively small number of non-DG customers.

- **Avoid competitive bypass.** A minimum bill can address impacts on non-participants by providing DG vendors with a signal to reduce the sizing of DG systems to keep customers above the minimum bill level, thus reducing the costs of net metering for other ratepayers. This still allows scope for customer choice of DG for usage above the minimum bill level. In contrast, if a fixed charge on residential DG is set too high, as DG and on-site storage technologies continue to develop and as their costs continue to fall, the response of consumers ultimately may be to "cut the cord" completely from utility service, as has happened with landline telephone service in many areas. In my opinion, such a result would be unfortunate, because the utility grid would lose important benefits that DG and on-site storage could provide for all ratepayers.

[27] For example, Idaho PUC, Final Order No. 32846 in Case No. IPC-E-12-27 (July 3, 2013), at pp. 3-5.
[28] See PUCN December 23, 2015 Order in Dockets Nos. 15-07-041 and 15-07-042, at p. 91, also CPUC Decision 16-01-044, at pp. 75 and 79.
[29] N.H. Rev. Stat. Ann. § 362-A:9.I.

E. Policy Reasons to Encourage Renewable DG

Q41: Are there any other important policy reasons why a state should maintain a supportive environment for customer-sited, distributed renewable generation?

A41: Yes. Rooftop solar and other renewable distributed energy technologies allow customers to take greater responsibility for their supply of electricity, compared to traditional service from the monopoly utility.

There are many benefits to a technology that allows customers greater choice in how they obtain their electricity. These include:

- **New Capital.** Customer-owned or customer-sited generation brings new sources of capital for clean energy infrastructure. Given the magnitude and urgency of the task of moving to clean sources of energy, expanding the pool of capital devoted to this task is essential.

- **New Competition.** Rooftop solar provides a competitive alternative to the utility's delivered retail power. This competition can spur the utility to cut costs and to innovate in its product offerings. With the widespread availability in the near future of customer-sited storage paired with rooftop solar, energy efficient appliances, and load management technologies, this competition will only intensify, given that the combination of solar and storage in the future may offer an electric supply whose quality and reliability approaches utility service.

- **Grid Services.** With deployment of smart inverters in the future, rooftop solar systems can provide voltage services, reactive power and other grid services. In addition, by reducing load on individual circuits, rooftop solar systems reduce thermal stress on distribution equipment, thereby extending its useful life and deferring the need to replace it. All of these additional values are difficult to quantify because there are not currently markets for these services, and utilities do not have an incentive to procure these types of services from third-party providers.

- **Enhanced Reliability and Resiliency.** Renewable distributed generation resources are installed as thousands of small, widely distributed systems and thus are highly unlikely to fail at the same time. Furthermore, the impact of any individual outage at a DG unit will be far less consequential, and less expensive for ratepayers, than an outage at a major central station power plant. Solar DG is located at the point of end use, and thus also reduces the risk of outages due to high loads on the transmission or distribution systems. Most electric system interruptions result from weather-related transmission and distribution system outages. In these events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

- **High-tech Synergies.** Rooftop solar appeals to those who embrace the latest in technology. Solar has been described as the "gateway drug" to a host of other energy-saving and clean energy technologies. Studies have shown that solar customers adopt more energy efficiency measures than other utility customers, which is logical given that it makes the most economic sense to add solar only after making other lower-cost efficiency improvements to your premises. Further, with net metering, customers retain the same incentives to save energy that they had before installing solar. These synergies will only grow as the need to make deep cuts in carbon pollution drives the increasing electrification of other sectors of the economy, such as transportation.

- **Customer Engagement.** Customers who have gone through the process to make the long-term investment to install solar learn much about their energy use, about utility rate structures, and about producing their own energy. Given their long-term investment, they will remain engaged going forward. There is a long-term benefit to the utility and to society from a more informed and engaged customer base, but only if these customers remain connected to the grid. As we have seen recently in Nevada, this positive customer engagement can turn to customer "enragement" if the utility and regulators do not accord the same respect and equitable treatment to customers' long-term investments in clean energy infrastructure that is provided to the utility's investments and contracts. Emerging storage and energy management technologies may allow customers in the future to "cut the cord" with their electric utility in the same way that consumers have moved away from the use of traditional infrastructure for landline telephones and cable TV. Given the important long-term benefits that renewable DG can provide to the grid if customer-generators remain connected and engaged, it is critical for regulators and utilities to avoid alienating their most engaged and concerned customers.

- **Self-reliance.** The idea of becoming independent and self-reliant in the production of an essential commodity such as electricity, on your own property using your own capital, has deep appeal to Americans, with roots in the Jeffersonian ideal of the citizen (solar) farmer.

The benefits of choice listed above are difficult to express in dollar terms; however, all are strong policy reasons for ensuring that the development of clean energy infrastructure includes policies which sustain a robust market for rooftop solar.

VII. ADDITIONAL PROGRAM DESIGN CONSIDERATIONS

Q42: Are there any additional issues that are important to address in considering the program design of a new, alternative net metering tariff?

A42: Yes. HB 1116 requires the Commission to consider "whether there should be a limitation on the amount of generating capacity eligible for such tariffs" and whether to change the "size limits" of facilities eligible for net metering.[30] Additionally, the law requires the Commission to consider whether to adopt a regulatory mechanism to allow utilities to receive timely cost recovery associated with net metering.

Q43: When should any new net metering tariff apply?

A43: HB 1116 provides some additional headroom for the net metering program, i.e., an additional 50 MW that is allocated among the distribution utilities. Any new, alternative net metering tariff adopted in this proceeding should only apply to customers of a specific utility after the utility reaches the expanded capacity limit

[30] RSA 362-A:9, XVI.

set by HB 1116. Once a utility certifies that they have reached the expanded net metering cap, the alternative net metering tariff design approved in this proceeding should be made available to new net metering customers. Customers that take service on the existing, original net metering tariff should be allowed to remain on their standard tariff until December 31, 2040, the date specified in HB 1116. In other words, existing NEM customers and future NEM customers who take service before the expanded HB 1116 capacity limit is reached should be grandfathered under the current NEM tariff until December 31, 2040.

Q44: Should any alternative net metering tariff adopted by the Commission have an overall limit on the amount of capacity eligible for the new alternative net metering tariff?

A44: No. There are several reasons why a participation cap is not warranted. First, the goal of a successor tariff to the legacy net metering program should be to create a sustainable mechanism. The Commission and stakeholders – including utilities, consumer advocates, environmental groups, and solar developers – should seek to avoid the disrupting fits and starts that can result from arbitrary program limits. Beyond technical limitations that may arise due to higher penetration at some time in the future, there is no good rationale to limit arbitrarily the potential size of the net metering market in New Hampshire.[31]

Second, the Commission's consideration of whether any limit is appropriate must also be informed by the costs and benefits of the program. As presented in the benefit-cost analysis which accompanies this testimony, net metering in its current form creates net benefits for New Hampshire ratepayers. Any modifications to the current mechanism (e.g., minimum bills, time-of-use rates, removal of public benefits charges and consumption taxes from the net metering

[31] Hawaii is the only U.S. solar market that has experienced significant technical issues due to high penetration of DG solar. These issues surfaced when DG solar penetration exceeded about 15% of customers on the island grids in Hawaii. The penetration of rooftop solar is far lower in New Hampshire today.

credit for exports) will only increase the net benefits flowing to other customers. Accordingly, a successor alternative net metering tariff that continues to be based on current volumetric retail rates will avoid unreasonable cost shifting and will result in just and reasonable rates for all ratepayers. There is no reason to limit a policy that provides such a demonstrable positive impact.

However, should circumstances change that throw into question the present reasonable balance of the benefits and costs of net metering, any future review of net metering tariffs and associated rate designs should occur within the context of a utility's general rate case (GRC). As should be obvious from the record in this case, an evaluation of the benefits and costs of net metering is a data-intensive exercise that requires many of the same analyses (such as marginal cost studies and cost allocation data used in rate design) that are typically available in data-rich GRCs. At that time, the Commission can again consider the benefits and costs of NEM in determining just and reasonable rates for all customers, including net metering customers. The structure of the net metering tariff itself, however, should be durable and should not be arbitrarily limited to a specific level of participation.

Q45: Do you recommend any change to the maximum system size limit for customers who take service under any alternative net metering tariff?

A45: No. Assuming that the basic structure of net metering remains intact, the existing 1 MW system size limitation allows a broad range of customer types to install on-site distributed generation to meet some or all of their electrical needs. This size limit encourages the development of smaller scale systems dispersed over a service territory, which can provide diversity benefits when compared to a much larger solar facility at a single point on the transmission grid. Moreover, the distribution grid, in most instances, will be able to accommodate the interconnection of projects in this range through expedited interconnection procedures without the need for upgrades. For larger distributed generation systems, pilot programs could be developed that target the specific needs of larger customers that cannot utilize net metering to offset most or all of their onsite load due to the 1 MW system size limit.

Q46: In terms of cost recovery for net metering, are there any mechanisms currently in place?

A46: New Hampshire law provides that a distribution utility may seek approval from the Commission for cost recovery of lost revenues from NEM, using a utility-specific methodology.[32] It is my understanding that a settlement agreement is currently before the Commission in Docket No. 15-147 that proposes a specific methodology for Unitil. I am not aware of any other utility that has sought relief through this provision or that has employed a different methodology than Unitil's proposal to calculate the effect of net metering on its default service and distribution revenues.

Q47: Do you support including a cost recovery mechanism for utilities as part of any new alternative net metering tariff?

A47: Yes. There is merit in developing an automatic rate adjustment mechanism for the utilities to recover lost net revenues (lost revenues net of avoided short-run costs) from new DG on an ongoing basis, in the years prior to the utility's next GRC. As shown in Docket DE 15-147, the amount of recovery to be achieved, at this time, is quite *de minimis*, accounting for a very small fraction of annual revenue. Until solar penetration begins to grow more rapidly, it is plausible that the legal and administrative costs of pursuing cost recovery under Puc 903.02(o) will often exceed the amount sought for recovery. An automatic adjustment mechanism to account for lost net revenues would help to hold the utilities harmless in the short-term to DG development, without the administrative burden of annual cost recovery proceedings.

[32] *See* New Hampshire Code Admin. Rules Puc 903.02(o).

Q48: Does the recovery of these short-term costs indicate that there is a cost shift to other customers?

A48: No. As discussed in the benefit-cost study summarized above and presented in detail in **Appendix D**, non-participating customers will see net benefits over the long run thanks to the investments which net metering customers are making in local renewable resources. However, these long-term net benefits will not be apparent when looking only at a short-term cost recovery mechanism. While I support a cost recovery mechanism to cover short-term costs, it is critically important to distinguish this mechanism from any assessment of long-term benefits and costs. A cost recovery mechanism provides a way to hold the utility harmless and to remove the utility's perverse incentive to discourage customers from investing in local renewable energy systems that will provide long term benefits and lower overall system costs for all customers.

The recovery of short-term costs – in the name of making the utility whole – should not obscure the longer term benefits that net metering systems can provide in reducing customer demand at the local and system levels, thus avoiding future infrastructure costs. Customer use of distributed generation reduces demand from the grid and can defer capacity additions and upgrades that the utility would have had to undertake but for the presence of customer-sited DG on the grid. Many of the avoided infrastructure benefits may never be specifically identified by utilities, because the utilities will never actually face the higher demands that would occur absent the development of customer-sited DG. Nonetheless, these long-term avoided costs represent real savings in infrastructure capacity and costs.[33] The counterfactual nature of many of these savings increases the importance of using marginal cost studies to understand how a

[33] Occasionally, a utility will recognize that changes in customer demand resulting from demand-side programs including DG have impacted its infrastructure investments. For example, Pacific Gas & Electric (PG&E) recently announced to the California Independent System Operator that it is cancelling 13 sub-transmission projects in its service territory, which would have cost $192 million, as a result of "a combination of energy efficiency and rooftop solar," according to PG&E. However, such recognition is more the exception than the rule. See "Cal-ISO Board Approves Annual Transmission Plan," *California Energy Markets* (No. 1379, April 1, 2016) at p. 10.

utility's long-term capacity costs are impacted by changes in demand. Similarly, net metered generation will reduce market prices and provide fuel hedging benefits that will inure to all customers, but that will never be directly observable in the market.

Q49: Does this conclude your prepared direct testimony?

A49: Yes, it does.

Appendix A

Curriculum Vitae of
R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)
   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)
   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)
   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)
   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)
   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
    b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 September 11, 1995)

- *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

- *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

- *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

- *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

- *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

- *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)
    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)
    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)
    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)
    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)
    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)
    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

- *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

- *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

- *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

- *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

- *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Joint Solar Parties** (R. 14-07-002—September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

    - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

    - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

    - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

    - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of Geronimo Energy, LLC. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

    - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

   - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony of R. Thomas Beach on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

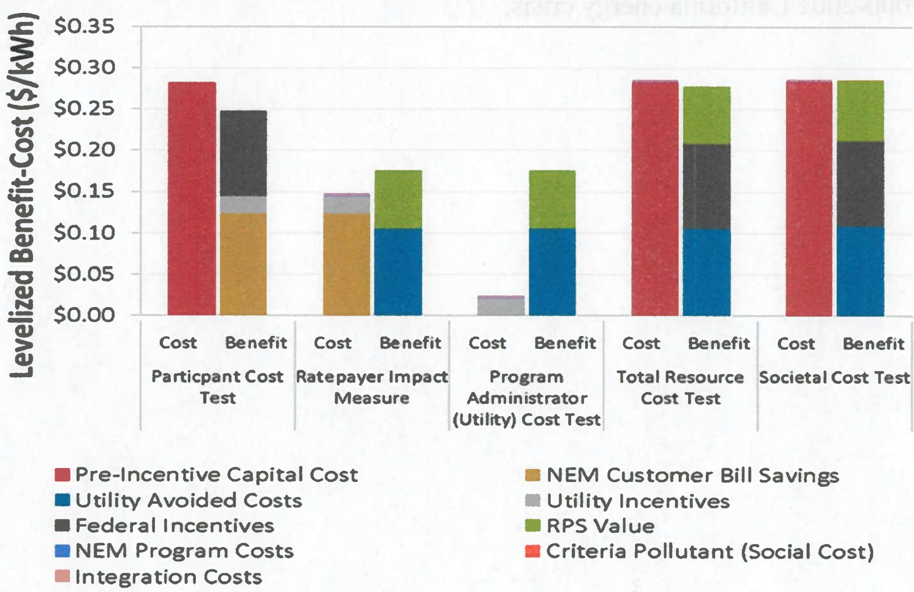
Appendix B

EXPERIENCE IN OTHER STATES: NEVADA, CALIFORNIA, AND MISSISSIPPI

1. Nevada

The Public Utilities Commission of Nevada ("PUCN") adopted a multi-perspective approach to the benefits and costs of net metering in the study which it released on July 1, 2014.[1] The consulting firm Energy and Environmental Economics (E3) performed the analytic work for this study, and I served on a Stakeholder Committee that the PUCN convened to provide input on the study methodology and analysis. **Figure B-1** below shows the costs and benefits of net-metering for solar PV systems in Nevada going forward, in the years 2014-2016, from each of the key stakeholders' perspectives.[2]

Figure B-1: *Public Utilities Commission of Nevada NEM Benefit-Cost Results*



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[1] The PUCN's net metering study, including the spreadsheet models used in the study, can be found at: http://puc.nv.gov/About/Media_Outreach/Announcements/Announcements/7/2014_-_Net_Metering_Study/ .

[2] This figure is from the "Results" tab of the "Nevada Public Tool" model, with the model set to produce results for solar PV and for the going-forward period of 2014-2016.

Notably, the Nevada study showed that NEM is cost-effective for non-participating ratepayers (*i.e.*, the benefits in the RIM test exceeded the costs), while the costs are somewhat higher than the benefits for participants (*i.e.*, for solar customers). As with any such set of cost-effectiveness tests, it is not reasonable or practical to expect each of these tests to achieve a precise 1.0 benefit/cost ratio. Instead, the goal should be to achieve a reasonable, equitable balance of benefits and costs for all concerned – solar customers, other ratepayers, and the utility system as a whole. In my judgment, the Nevada study demonstrated that NEM at the full retail rate, without any further rate design modifications, achieved that desired "rough justice" balance of interests in Nevada.

The Nevada Commission subsequently moved away from the use of a long-term benefit-cost approach to analyze NEM in that state. In 2015, in response to new legislation, the PUCN reviewed a study from NV Energy that was limited to the short-term cost of service for residential and small commercial customers who install solar DG. The PUCN's subsequent decision on December 23, 2015 accepted the results of that study, and, based on that evidence, found that there was a significant cost shift from non-participating ratepayers to solar DG customers. As a result, the PUCN ended NEM in Nevada, increased the fixed monthly customer charge for DG customers, and reduced the export rate credited to DG systems from the full retail rate (about 11 cents per kWh for residential customers) to an energy-only avoided cost rate of 2.6 cents per kWh. The PUCN took this action even though its order found that there are the following 11 components to the net benefits of DG (based on an adopted stipulation on NEM issues from South Carolina), and that it was only able to quantify the first two components of DG value in the adopted 2.6 cents per kWh export rate:

1. Avoided energy costs
2. Line losses
3. Avoided capacity
4. Ancillary services
5. Transmission and distribution capacity

6. Avoided criteria pollutants
7. Avoided CO_2 emission costs
8. Fuel hedging
9. Utility integration and interconnection costs
10. Utility administration costs
11. Environmental costs[3]

The impacts of the December 2015 decision have been devastating for the solar DG market in Nevada. The reduction in the export rate and the increased fixed charge have reduced the bill savings available to NEM customers in Nevada by 40% or more. Solar DG is no longer economic for new systems. This is the case today, even though the PUCN, most recently, has grandfathered the 32,000 existing NEM customers under the prior NEM rules with a full retail rate credit for exported power.[4] In sum, the elimination of NEM and, in particular, the reduction in the export rate, has decimated the rooftop solar market in Nevada, resulting in more than 1,000 documented layoffs at solar companies.[5]

2. California

The investor-owned utilities in California have reached or are approaching that state's 5% cap on NEM systems. In 2015, the California Commission asked parties to analyze their proposals for a NEM successor tariff using a common "Public Tool" spreadsheet program similar to the Nevada NEM benefit-cost model. Like the Nevada model, the California Public Tool analyzes a proposed tariff from multiple perspectives, using all of the *SPM* cost-effectiveness tests and looking at the long-term, life-cycle costs and benefits. The CPUC received detailed analyses of NEM benefits and costs using the Public Tool from a variety of parties. In January 2016, the California commission decided to extend NEM in California until a further review in 2019, with certain changes such as requiring NEM customers to be on TOU rates, removing certain public benefit charges

3 See PUCN December 23, 2015 Order in Dockets Nos. 15-07-041 and 15-07-042, at pp. 66-67 and 95-96.
4 See PUCN September 16, 2016 Order in Dockets Nos. 16-07-028 and 16-07-029.
5 See *Prepared Direct and Rebuttal Testimonies of R. Thomas Beach on behalf of TASC*, served February 1 and 5, 2016 in PUCN Dockets Nos. 15-07-041 and 15-07-042.

from export rates, and requiring NEM customers to pay interconnection costs. The CPUC's order does not rely on the Public Tool analyses, because important information related to both costs (rate design changes) and benefits (locational benefits on the distribution grid and societal benefits) remain under development in other CPUC proceedings. However, the CPUC made clear that it intends to continue to refine and to use this SPM-based, long-term benefit-cost approach in its future evaluations of NEM and DG.[6]

3. Mississippi

The Public Service Commission of Mississippi completed a NEM benefit/cost analysis in 2014, and NEM is being implemented for the first time in Mississippi.[7] As in the Nevada NEM study, the Mississippi study considered the three principal perspectives discussed above, with a focus on the TRC test because that test best captures the benefits and cost for the state as a whole from this new resource. The Mississippi study also used a 25-year time horizon. The following figure summarizes the mid-case costs and benefits from Mississippi's TRC analysis, plus the maximum low and high sensitivity cases for the benefits.

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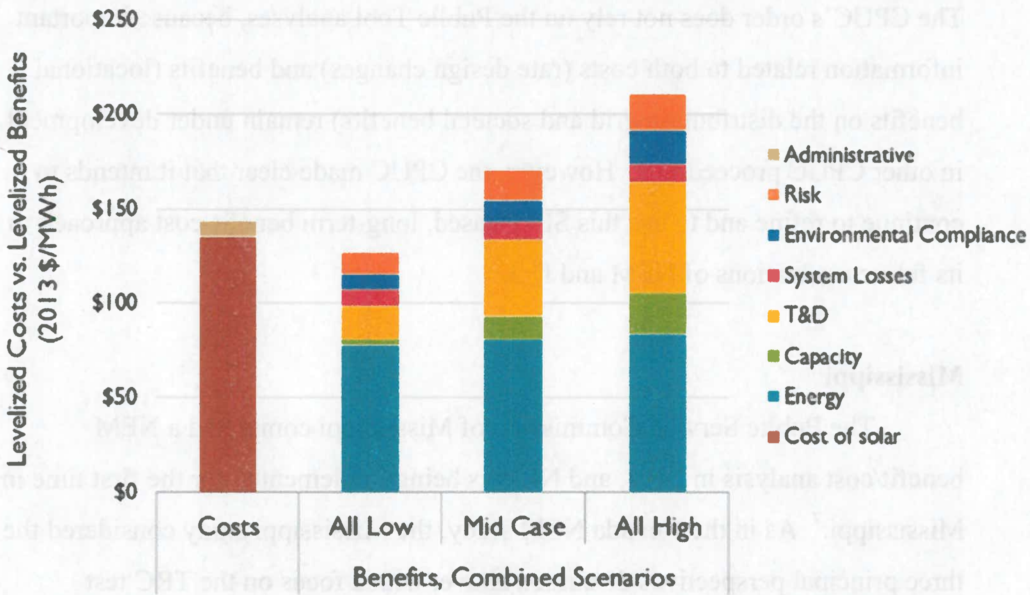
6 See CPUC Decision 16-01-044, at pp. 48-50, 54-61, and 80-82.

7 Elizabeth A. Stanton, *et al.*, *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* (Synapse Energy Economics for the Public Service Commission of Mississippi, released September 19, 2014); hereafter "Mississippi Study." Available at http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

Figure B-2: *Public Service Commission of Mississippi NEM Study Results*



As a result of this analysis, the Mississippi study concluded that net metered solar projects will provide a net benefit to Mississippi in almost all of the cases considered. However, the study's analysis of the Participant cost test expressed concern that NEM bill savings at the retail rate will not provide adequate benefits to drive significant adoption of solar DG in the state. As a result, the study suggested that solar customers should be compensated at a rate higher than retail rates. This higher rate would be based on the utilities' avoided cost benefits, so that it would not shift costs to non-participants.[8] Finally, the Mississippi Study criticized the use of the traditional RIM test, particularly in the context of a new NEM program. The problem with the RIM test is that the cost shift measured by the RIM test is simply a re-allocation of costs which the utilities have already incurred and which are not incremental costs resulting from the NEM program. Due to this limitation, the study concluded that RIM test should not be used to judge the merits of the new NEM program.[9]

[8] Mississippi Study, at pp. 49-50.
[9] *Ibid.*, at pp. 41-43 and Figure 18.

Appendix C

DE 16-576 Outline of Costs & Benefits of NM Systems and Related Variables and Rate Components to be Considered

The New Hampshire Sustainable Energy Association is providing the following list of proposed costs and benefits of net metering systems in order to foster a conversation at the next technical session. The provision of this list should not be construed as a waiver of or act to foreclose NHSEA's ability to address different or additional costs and benefits in this docket.

I. Avoided Energy Supply Costs and Related Benefits
(See Puc 903.02 as a starting point)

a. Generation LMP, simple average vs. time weighted (RTP)
b. Ancillary Charges related to and linked to LMP charges
   i. Ancillary Markets (i.e. Regulation Market, Forward Reserve Mark et, Real-Time Reserve Market, Transitional Demand Response Program)
   ii. Net Commitment-Period Compensation, 1st & 2nd contingency
   iii. Miscellaneous Credits/Charges (i.e. Inadvertent Energy, Marginal Loss Revenue Fund, Financial Transmission Rights (FTR) Auction Revenue Rights)
   iv. Wholesale Market Service Charge (i.e. ISO Tariff Schedule 2 and 3 Expenses, NEPOOL Expenses)
c. Capacity Avoided Costs (FCM charges)
d. Line Loss Factors
e. One size fits all for NEM systems vs. distinguishing between solar and other DG
f. Applicable intervals
g. DRIPE (Demand Reduction Induced Price Effect) i.e.. - Energy market effects; less energy purchases lowers market clearing prices, lower wholesale demand lowers FCM clearing price
   i. Energy
   ii. Capacity
h. Supply diversity and hedging benefits

II. Avoided Transmission Costs

a. Regional Network Service (PTF or pooled transmission facilities)
b. Local Network Service (non-PTF)
c. Line Loss Factors

III. Avoided & Incurred Distribution Costs & Benefits

a. Costs to Distribution grid, actual & potential
   i. Cost to installers for interconnection
   ii. Utility costs to process & integrate DER beyond those paid by installers
   iii. Administrative & billing costs
   iv. Other costs
b. Benefits to Distribution grid, actual & potential
   i. Avoided new capacity investments (NWA - non wires alternatives)
   ii. Equipment life extension
   iii. Voltage and power quality support
   iv. Other distribution benefits
c. Locational Aspects
d. Rate Design questions, fixed and variable components, demand charges, interval and flows for determining charges

IV. **Renewable Energy Credits (RECs), RPS Compliance and other miscellaneous charges** (SBC, SCRC, Electricity Consumption Tax)

V. **Avoided Environmental Costs or Derived Benefits**
   a. NOx and CO2 compliance costs
   b. Net social costs NOx, SO2, CO2, other pollutants (environmental externalities beyond compliance costs)
   c. Other

VI. **Other Non-energy Benefits**
(e.g. economic development, job creation, tax revenue)

VII. **Overarching** – use of modeled vs. actual PV and other NEM hourly data

VIII. **Utility Recovery of Lost Distribution Revenue**
   a. Behind the meter consumption
   b. Bill credits for all exports

IX. **Any size & eligibility limits**

   a. Need there be any limits on DG capacity due to reliability or other engineering concerns? If so, how and when determined?
   b. Is there any basis or good reason to have any other size or eligibility limits on tariffs.

X. **Other market segmentation**

Appendix D

The Benefits and Costs of Distributed Solar Generation in New Hampshire

This appendix presents a benefit-cost analysis of the impacts of distributed solar generation ("solar DG") on ratepayers in the service territories of the three investor-owned utilities in New Hampshire – Eversource, Liberty, and Unitil. This work considers the benefits and costs of solar DG from the perspectives of all of the key stakeholders – solar DG customers, other ratepayers, and the system and society as a whole – who together constitute the public interest in the development of DG resources in New Hampshire. To consider all of these perspectives, we examine the benefits and costs of solar DG using the full set of cost-effectiveness tests for demand-side resources that commonly are used in the utility industry. We use a long-term, life-cycle analysis that covers the useful life of a solar DG system (25 years). This evaluates the benefits and costs of solar DG on the same basis as other utility resources on both the demand- and supply-sides.

The cost-effectiveness tests for demand-side resources use benefits and costs that we calculate using three principal analyses:

- An analysis of the **direct ratepayer benefits** of solar DG, in terms of the costs that the utilities will avoid as a result of solar DG development. These benefits are used in the Total Resource Cost ("TRC") and Ratepayer Impact Measure ("RIM") tests. In the Societal test, these direct benefits are supplemented by additional **societal benefits** that accrue to society as a whole.

- A calculation of the life-cycle **costs of installing and operating** solar DG systems, used in the Participant and TRC tests.

- Analysis of the **bill savings** which participating customers realize from their solar DG installations. This is the principal benefit for these customers in the Participant test. The bill savings are also **lost revenues** for the utility, which constitute the principal costs for non-participating ratepayers in the RIM test.

This report presents and discusses each of these analyses, for the three utilities.

1. Benefits of Solar DG

a. Avoided energy costs.

We calculate avoided energy costs based on ISO New England ("ISO-NE") locational marginal price ("LMP") data for New Hampshire. We calculate a PV-weighted average of hourly day-ahead LMP prices for the year ending in the third quarter (3Q) of 2016 equal to about $32 per MWh, with small differences among the three utilities based on slightly different solar output profiles.[1] This 2015-2016 energy price is then escalated to future years using a long-term forecast of natural gas market prices that is based, for the initial twelve years, on natural gas forward prices in the benchmark Henry Hub market and, in subsequent years, on the escalation in natural gas prices at the Henry Hub in the forecast in the Energy Information Administration's ("EIA") *Annual Energy Outlook 2016*, released in September 2016. This is the same approach used in the Maine Public Utilities Commission's March 2015 *Maine Distributed Solar Valuation Study (Maine Study).*[2] We separately escalate the portion of LMP prices that recovers allowance costs in the New England carbon market (the Regional Greenhouse Gas Initiative ["RGGI"]), based on our forecast of RGGI prices that is discussed in Section 1h below. We levelize the resulting 25-year forecast of solar-weighted LMPs using each utility's weighted average cost of capital ("WACC") as the discount rate. These levelized avoided energy costs are about $63 per MWh after adjusting for the utility-specific distribution line losses that the utilities provided in discovery.

Table D-1: *Avoided Energy Cost (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Levelized LMP	58.79	58.91	58.48
Line Losses	7.75%	6.90%	6.47%
Avoided Energy Cost Including Line Losses ($/MWh)	63.35	62.98	62.27

b. Avoided generation capacity costs

Our projection of avoided generation capacity costs is based on results from ISO-NE's forward capacity market ("FCM") Auctions 9 and 10,[3] plus the projection for future avoided capacity costs included in the most recent regional forecast of avoided costs used for demand-side programs, *Avoided Energy Supply Costs in New England: 2015 Report*

[1] We used the National Renewable Energy Laboratory's ("NREL") Solar Advisor Model ("SAM") to calculate the output of representative solar PV systems in Manchester (Eversource), Concord (Unitil) and Lebanon (Liberty).

[2] Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015), hereafter "Maine Study." Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

[3] See http://www.iso-ne.com/static-assets/documents/2016/02/fca_10_result_report.pdf.

(2015 AESC).[4] Based on this forecast of annual capacity values in the New England market, we determine a levelized capacity price ($/kW-year) for each of the three utilities, again using the current WACC as the discount rate. We then convert this levelized price to an energy price equivalent (in $/MWh) by dividing by expected annual solar production.

To determine the amount of capacity that a solar project provides, we perform a load match analysis that looks at the median of hourly PV capacity factors during the top 100 annual load hours in the New Hampshire zone on the ISO-NE system.[5] We conduct this analysis using hourly loads in three years (2011, 2012, and 2013) and average the annual results. In this analysis, we used actual solar insolation data from 2011-2013 to calculate PV system output using SAM, in order to obtain a more accurate correlation between solar output and actual utility loads in these years.[6] In other words, using actual loads and solar insolation recognizes that hot, sunny, summer days when electric loads are high also tend to be days with high PV output. If typical meteorological year (TMY) data were used for solar output, this correlation would be lost. In fact, the load match factors would be over 20% lower using TMY data for solar output.

Table D-2: *Avoided Generation Capacity Costs (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Levelized Net CONE ($/kW-year)	165.21	163.77	162.12
÷ Solar Output (kWh per kW-AC)	1,324	1,274	1,424
= Generation Capacity Cost ($/MWh)	124.87	128.52	113.83
x PV Load Match (%)	48.8%	40.2%	50.9%
+ Line Losses (%)	7.75%	6.90%	6.47%
= Avoided Generation Capacity ($/MWh)	65.62	55.26	61.66

We estimate that an additional capacity reserve margin of 14.3% is needed to capture the long-term resource adequacy requirements in New England. The ISO-NE uses an indicative 14.3% reserve margin for future years in its *2015 Regional System Plan.*[7] As a result of this reserve capacity requirement, generating capacity must be purchased to cover 114.3% of peak loads to provide the reserve margin necessary to ensure system reliability given contingencies and variations in peak loads.

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[4] See *2015 AESC*, at Appendix B., Tables One and Two for New Hampshire. This report is available at https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf.

[5] See *Maine Study,* at pp. 24-25.

[6] New Hampshire solar insolation in 2011-2013 is taken from Clean Power Research's *Solar Anywhere* database.

[7] See ISO-NE, *2015 Regional System Plan*, at pp. 65 and 67.

Table D-3: *Avoided Generation Capacity Reserves (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	**Liberty**	**Unitil**
Avoided Generation Capacity ($/MWh)	65.62	55.26	61.66
x Planning Reserve Margin (%)	14.3%	14.3%	14.3%
= Avoided Generation Capacity Reserve ($/MWh)	9.38	7.90	8.82

c. Avoided transmission capacity costs

The majority of the output of solar DG serves on-site loads and never touches the grid, and thus clearly reduces loads on the transmission system. For the minority of power that a solar DG unit exports to the grid, these exports are likely to be entirely consumed on the distribution system by the solar customer's neighbors, unless solar penetration is very high. Thus, like energy-efficiency and demand response resources, solar DG reduces load growth and displaces traditional generation sources that must use the utility transmission system to be delivered to customers. As a result, solar DG will avoid transmission capacity costs to the extent that solar production occurs during the peak demand periods that drive transmission costs.

We calculate avoided transmission costs using ISO-NE's Regional Network Load (RNL) transmission costs for New Hampshire, for the year ending May 2016.[8] There was a significant increase in these costs which took effect on June 1, 2015. We escalate these costs based on the forecast of these costs that is included in the ISO-NE *2015 Regional System Plan*,[9] then at a 2% annual inflation rate thereafter, and levelize them using the utility WACCs. Because ISO-NE allocates these costs based on monthly peak loads, the PV Load Match factor is calculated as the average reduction in each utility's 12 monthly coincident peak demands ("12 CP") due to PV output, per kW of PV nameplate capacity. Again, this set of load match factors is also computed using actual 2011-2013 loads and solar insolation.

We have not developed marginal costs for transmission facilities that the New Hampshire utilities operate that are not part of the ISO-NE regional network, so these avoided transmission capacity costs may be conservative.

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8 See ISO-NE, *Monthly Regional Network Load Cost Report* (July 2016), at Table 8-1. Available at http://www.iso-ne.com/markets-operations/market-performance/load-costs.

9 ISO-NE, *2015 Regional System Plan*, at p. 111 (Table 6-2).

Table D-4: *Avoided ISO-NE Transmission Costs (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
RNL Transmission Costs ($/kW-year)	105	105	105
RNL Transmission Costs – NH ($/kW-year) – *25-year levelized*	136.67	136.15	135.56
÷ Solar Output (kWh per kW-AC)	1,324	1,274	1,424
= Transmission Capacity Cost ($/MWh)	103.21	106.84	95.19
x PV Load Match using 12 CP (%)	17.6%	14.9%	17.1%
+ Line Losses (%)	7.75%	6.90%	6.47%
= Avoided ISO-NE Transmission Capacity ($/MWh)	19.58	17.06	17.28

d. Market price response (DRIPE)

We have incorporated data from the *2013 and 2015 AESC* reports on the market price reductions that will result from the on-site solar distributed generation in New Hampshire that serves load directly. This market benefit is also known as the demand reduction induced price effect, or DRIPE. There is a significant difference in the DRIPE impacts in New Hampshire between the *2013* and *2015 AESC* reports, as a result of significant changes in the methodology for the DRIPE calculations in the *2015 AESC*.[10] For example, the *2015 AESC* assumes (1) a much shorter duration for energy DRIPE impacts (three years) and (2) zero capacity DRIPE as a result of an assumed near-term need for new capacity in New England. We have not attempted to resolve these differences, but have used the average of the DRIPE impacts between the two studies. For capacity DRIPE, we use the *2015 AESC* assumption of zero capacity DRIPE as it is consistent with our avoided capacity cost forecast.

Table D-5: *DRIPE (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Levelized LMP	63.35	62.98	62.27
DRIPE Benefit (% of LMP)	4.14%	4.30%	4.46%
+ Line Losses (%)	7.75%	6.90%	6.47%
DRIPE Benefit ($/MWh)	2.82	2.89	2.96

[10] See *2015 AESC*, at pages 1-5 and 1-16 to 1-17.

e. Avoided fuel price uncertainty

Solar DG displaces natural gas, and thus reduces the exposure of New Hampshire ratepayers to the future uncertainty and volatility in natural gas prices. To calculate this benefit, we follow the methodology used in the *Maine Study*. This approach recognizes that one could contract for future natural gas supplies today, and then set aside the money to buy that gas in the future in risk-free investments. This would eliminate the uncertainty in future gas costs. The additional cost of this approach compared to purchasing gas on an "as you go" basis (and using the money saved for alternative investments) is the benefit of reducing the uncertainty in the costs for the fuel that solar DG displaces.

Table D-6: *Avoided Fuel Price Uncertainty (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Avoided Fuel Price Uncertainty ($/MWh)	25.45	27.44	29.75
+ Line Losses (%)	7.75%	6.90%	6.47%
Avoided Fuel Price Uncertainty ($/MWh)	27.43	29.33	31.67

f. Avoided distribution capacity costs

Distributed solar generation can reduce peak loads on distribution circuits, and thus avoid or delay the need to upgrade or re-configure the circuit if it is approaching capacity. The majority of solar DG output serves the on-site load and will never flow onto the distribution system, and thus reduces the loads served from the local distribution system. In addition, exports from solar DG to the distribution system serve local loads, and thus unload upstream portions of the distribution system. Over the 25-year life of DG systems, these load reductions will avoid or defer distribution system expansions or upgrades and extend the life of existing equipment.

The extent to which solar generation avoids distribution capacity costs is a more complex question than for transmission. Distribution substations and circuits can peak at different times than the system as a whole, which complicates the calculation of by how much solar DG can reduce distribution loads and avoid distribution capacity costs. As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loads, utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid distribution capacity costs.[11] A comparable evolution has occurred over the last several decades, as the long-term

[11] Moving forward, with the advent of smart inverters and other technologies, PV systems will be able to provide additional services and avoid additional costs than those attributable to capacity expansion alone. Such services include voltage regulation, power quality, and conservation voltage reduction. For these reasons, the existing estimates of marginal distribution costs should be considered conservative.

impacts of energy efficiency and demand response programs are now incorporated into utilities' capacity expansion plans, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed are difficult to predict.

Our calculation of avoided distribution capacity costs begins with the utilities' marginal distribution costs. We use the marginal distribution capacity costs which Liberty and Unitil recently filed at the Commission; these marginal costs are based on regression analyses of the relationship between distribution capital additions and load growth. We performed a similar regression analysis for Eversource, which does not have a recent marginal cost study, using FERC Form 1 data.

We then allocate these marginal distribution costs to the high-demand hours of the year using an allocation based on a set of hourly "peak capacity allocation factors" ("PCAFs") derived from 2015 hourly data on distribution substation loads for each utility.[12] The PCAFs are based on hourly substation loads that are within 10% of the annual peak load at each substation, using this formula:

$$PCAF_s(h) = \frac{(Load_s(h) - Threshold_s)}{\sum_{k=1}^{8760} Max[0, (Load_s(k) - Threshold_s)]}$$

where:

$PCAF_s(h)$ = peak capacity allocation factor for substation *s* in hour *h*,
$Load_s(h)$ = the load for substation *s* in hour *h*, and
$Threshold_s$ = 90% of the substation *s* annual peak load.

All hours where the substation load is below 90% of the annual peak are excluded from the calculation of hourly PCAFs. The resulting hourly profile of PCAFs across all of the utility's substations is used to allocate the utility's marginal distribution capacity costs to each hour. Finally, these hourly avoided distribution costs are applied to the hourly output profile of solar DG to calculate avoided distribution capacity costs. This step is shown graphically in **Figure D-1**. The resulting avoided distribution capacity costs are presented in **Table D-7**. The solar- and PCAF-weighted avoided distribution

[12] This approach has been used in the "Public Tool" benefit/cost model of renewable DG developed by Energy and Environmental Economics (E3) for the California Public Utilities Commission ("CPUC"), and used to determine avoided sub-transmission and distribution capacity costs for the California electric utilities. The CPUC's Public Tool model and the association documentation are available at http://www.cpuc.ca.gov/general.aspx?id=3934. The marginal subtransmission and distribution costs are shown in Lines 323-350 of the "Avoided Cost Calcs" tab; the PCAF allocation factors by TOU period are listed in Lines 352-371 of the same tab. The PCAF method also has been used in Colorado. See Crossborder Energy, *Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado: A Critique of PSCo's Distributed Solar Generation Study* at pp. 9-11 (December 2, 2013). This study was filed in Colorado Public Utilities Commission Docket No. 13A-0836E on behalf of TASC.

costs, divided by total marginal distribution costs, yield an aggregate PV load match factor at the distribution level, which is also shown in Table D-7.

Figure D-1: Eversource Substation PCAFs and DG Output

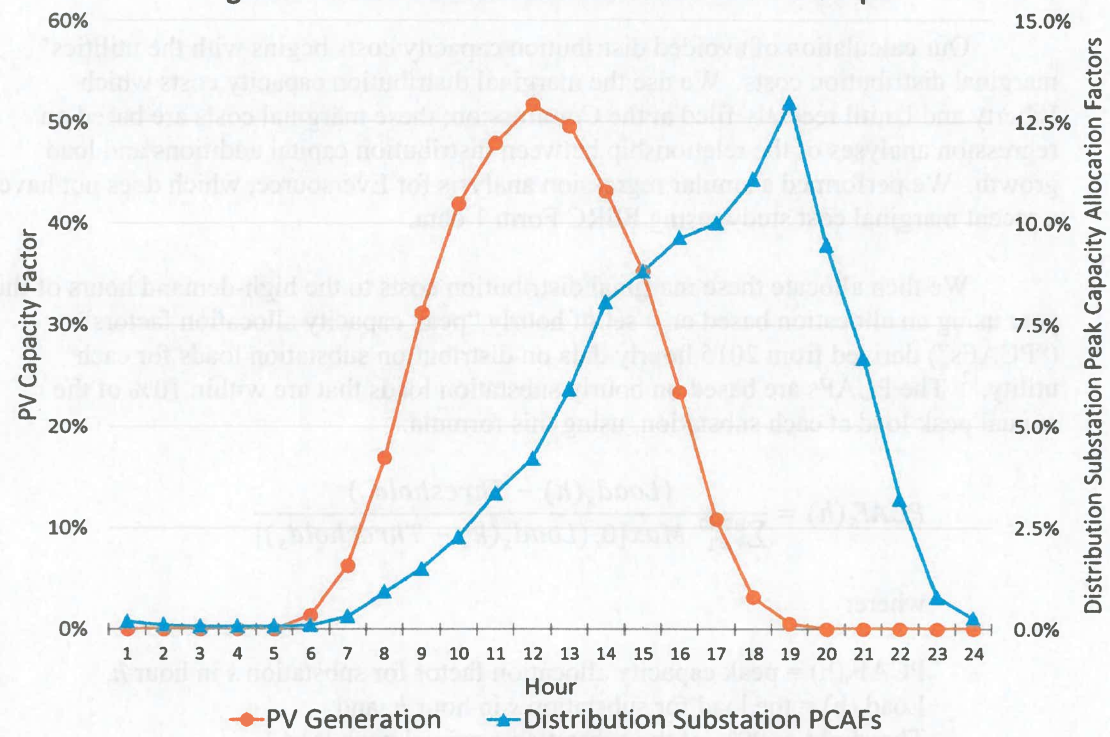

Table D-7: *Avoided Distribution Capacity Costs (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Marginal Distribution Costs ($/kW-year)	133.14	127.61	91.26
÷ Solar Output (kWh per kW-AC)	1,324	1,274	1,424
= Distribution Capacity Cost ($/MWh)	100.55	100.14	64.08
x Effective PV Load Match using Distribution Substation PCAFs (%)	22.3%	29.3%	25.8%
= Avoided Distribution Capacity ($/MWh)	22.46	29.36	16.55

g. Integration and program administration costs

Next, we subtract certain costs from the benefits. First, we subtract an estimate of solar integration costs of $2 per MWh, based on costs from the New England Wind Integration Study.[13] Finally, we add 0.3 cents per kWh for the levelized cost of utility administration of the DG program, from the detailed data on such costs that was assembled last year for the California Public Tool model referenced above.[14]

h. Societal benefits

Renewable DG has benefits to society that do not directly impact utility rates. When renewable generation takes the place of conventional fossil fuel generation, all citizens benefit from reductions in air pollutants that harm human health and exacerbate climate change. Demand on existing water supplies is reduced, avoiding the potential need to acquire new sources of supply. Distributed generation, by siting energy generation in the built environment, results in more land being available for other uses, or as natural habitat. Distributed generation makes the power system more resilient, and stimulates the local economy. Many of these benefits can be quantified, as discussed below. We use a lower, societal discount rate of 3% in calculating these benefits, rather than the utility WACCs used for the direct benefits.

Our societal benefits use the Environmental Protection Agency's ("EPA") "AVoided Emissions and geneRation Tool" (AVERT) to calculate the avoided emissions due to solar DG installations in New Hampshire. AVERT calculates hourly avoided emissions based on a given energy efficiency or renewable energy program. Our model assumes 40 MW of DG solar in the state, uses a PV profile for Concord, and the Northeast AVERT regional data file to calculate the avoided emissions in New Hampshire. The avoided emissions for 2015 are shown below.

Table D-8: *2015 Avoided Emissions*

Pollutant	Avoided Emissions	
	lbs	lbs/MWh
SO2	31,400	0.617
NOx	33,100	0.650
CO2	27,400	0.538

The value of these avoided emissions is calculated as follows:

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[13] This estimate is based on the Maine Study's calculation that a 2.5% penetration of wind resources in New England would require additional operating reserves equal to 1.75% of the wind capacity. See Maine Study, at p. 80. We use 1.75% of the avoided generation capacity costs (before the load match factor) in Table D-2 above. This estimate is also consistent with other solar integration studies in the U.S., such as the studies referenced in footnote 7 of the accompanying testimony.

[14] See footnote 12 above.

1. Determine the amount of avoided emissions using AVERT as described above.
2. Calculate the social cost of the avoided emissions and subtract the market value of those emissions.

Carbon. The total social cost of carbon is taken from the EPA's 2015 revision of the *Social Cost of Carbon for Regulatory Impact Analysis*.[15] The EPA calculates the social cost of carbon from 2015-2050 in five year intervals. In this analysis, intermediate years between the five year intervals are interpolated. For the market value of carbon (which we include in avoided energy costs), we extend recent RGGI auction prices through 2021, after which we use the forecasted market value of carbon in Synapse Energy Economic's *Spring 2016 National Carbon Dioxide Price Forecast*.[16] Forecasted market CO_2 values for the years 2016 – 2040 are subtracted from the EPA's social cost of carbon to determine the net social cost of carbon.

SO_2. The analysis for SO_2 follows the same steps as the analysis for carbon. The total social cost of SO_2 is taken from the EPA's *Regulatory Impact Analysis for the Final Clean Power Plan (CPP Impact Analysis)*.[17] The EPA calculated social cost values for 2020, 2025, and 2030. This analysis uses the values given for these three years assuming a 3% discount rate. Values for intermediate years are interpolated between the five-year values. The market value of SO_2 is taken from the EPA's 2016 SO_2 allowance auctions. However, the final clearing price of the latest spot auction was $0.06 per ton.[18] This is low enough compared to the social cost that it is negligible for our calculations.

NOx. The social cost of NOx is the social cost from the EPA's *CPP Impact Analysis*.[19] There is no compliance market price for NOx in the Northeast.[20]

Local Economic Benefits. Distributed generation has higher costs per kW than central station renewable or gas-fired generation. However, a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – is spent in the local economy, and thus provides a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. In contrast, central station power plants have significantly lower soft costs, per kW installed, and often are not located in the local area where the power is consumed.

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[15] *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013, Revised July 2015). Available at: https://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

[16] *Spring 2016 National Carbon Dioxide Price Forecast*. Found at: http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf.

[17] *Regulatory Impact Analysis for the Final Clean Power Plan*. Found at: https://www.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf.

[18] EPA 2016 SO2 Allowance Auction. Found at: https://www.epa.gov/airmarkets/2016-so2-allowance-auction.

[19] *CPP Impact Analysis*, at Table 4-7.

[20] See the EPA Cross State Air Pollution Rule. Found at: https://www3.epa.gov/crossstaterule/

There have been a number of recent studies of the soft costs of solar DG, as the industry has focused on reducing such costs, which are higher in the U.S. than in other major international markets for solar PV. The following tables present data from detailed surveys of solar installers conducted by two national labs (LBNL and NREL), which break out the soft costs that are likely to be spent in the local area where the DG customer resides.

Table D-9: *Residential Local Soft Costs*

Local Costs	LBNL – J. Seel *et al.*[21]		NREL – B. Friedman *et al.*[22]	
	$/watt	%	$/watt	%
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer acquisition	0.58	9%	0.48	9%
Installation labor	0.59	10%	0.55	11%
Permitting & interconnection	0.15	2%	0.10	2%
Permit fees	0.09	1%	0.09	2%
Total local soft costs	**1.41**	**22%**	**1.22**	**23%**

Table D-10: *Commercial Local Soft Costs*

Local Costs	NREL – B. Friedman *et al.*			
	Small Commercial		Large Commercial	
	$/watt	%	$/watt	%
Total System Cost	4.97	100%	4.05	100%
Local Soft Costs				
Customer acquisition & marketing	0.13	3%	0.03	1%
Installation labor	0.39	8%	0.17	5%
Permitting & interconnection	0.01	0.2%	0.00	0%
Permit fees	0.07	1%	0.04	1%
Total local soft costs	**0.60**	**12%**	**0.24**	**6%**

These local economic benefits occur in the year when the DG capacity is initially built. We have converted these benefits into a $ per kWh benefit over the expected DG lifetime that has the same NPV in 2016 dollars. We also use more recent (and lower) solar DG capital costs than the system costs used in the LBNL and NREL studies. The result is a societal benefit of 4.6 cents per kWh of DG output for residential systems and

[21] J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37.
[22] B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2.

2.7 cents per kWh for commercial, or an average of 3.8 cents per kWh assuming 56% residential systems, 44% commercial.[23]

Table D-11 summarizes the societal benefits we have calculated.

Table D-11: *Societal Benefits (25-year levelized $/MWh)*

Benefit	Value
Social cost of carbon – reduced damages	23.23
Health benefits – lower PM-2.5 and NOx emissions	36.40
Local economic benefits	38.24
Total Societal Benefits	97.86

i. Summary of Benefits.

Table D-12 summarizes the benefits discussed above. See also **Figure ES-1**.

Table D-12: *Summary of Solar DG Benefits (25-year levelized $/MWh)*

Avoided Cost Component	Utilities		
	Eversource	Liberty	Unitil
Direct			
Energy	63.35	62.98	62.27
Generation Capacity	65.62	55.26	61.66
Generation Capacity Reserves	9.38	7.90	8.82
Solar Integration Costs	*(2.00)*	*(2.00)*	*(2.00)*
ISO-NE Transmission Capacity	19.58	17.06	17.28
Distribution	22.46	29.36	16.55
Market price response (DRIPE)	2.82	2.89	2.96
Program administration	*(3.00)*	*(3.00)*	*(3.00)*
Avoided Fuel Price Uncertainty	27.43	29.33	31.67
Total Direct Benefits	205.64	199.79	196.20
Societal			
Carbon		23.23	
Criteria Pollutants (SOx and NOx)		36.40	
Local economic benefits		38.24	
Total Societal Benefits		97.86	
Total Benefits			
Direct and Societal	303.50	297.70	294.10

[23] This is the current distribution between residential and commercial customers of the 40 MW of solar DG systems now online in the three utility service territories, based on data provided in discovery.

2. Costs of Solar DG for Participants

We have used a pro forma cash flow analysis to project the lifecycle cost of a solar DG system based on 2014-2015 solar system costs in New Hampshire surveyed and reported by Lawrence Berkeley National Lab ("LBNL") in their annual *Tracking the Sun* report.

LBNL's most recent *Tracking the Sun VII and IX* reports from August 2015 and August 2016 include the results of their extensive survey of the trends in solar prices in 2014 and 2015. LBNL's authoritative price surveys of PV installations are based on data from almost one-half of the 965,000 solar PV systems installed in the U.S. through calendar year 2015.[24] **Table D-13** shows this price data for New Hampshire for 2014 and 2015. Residential PV system costs in 2015 actually increased slightly compared to 2014. We have used the lower of 2014 or 2015 costs in our model.

Table D-13: *2014 and 2015 Solar PV Installed Price Data for New Hampshire*[25]

Market Segment	Cost Percentile	Solar PV Costs ($ per watt DC)		
		2014	2015	Model
Residential (< 10 kW)	Median	**3.60**	**3.90**	**3.60**
	20%	3.20	3.40	3.20
	80%	4.50	4.50	4.50
Small Commercial (10 kW to 500 kW)	Median	**3.40**	**3.30**	**3.30**
	20%	3.00	3.00	3.00
	80%	4.00	3.80	3.80

Our principal assumptions in the residential cash flow analysis are summarized in **Table D-14**. We include the modest state incentive as a reduction in participant costs, and also assume that about 50% of solar customers will face property taxes equal to 2% of their system's assessed value.[26] Our analysis also uses typical solar loan terms now offered in New Hampshire.

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[24] LBNL, *Tracking the Sun IX* (August 2016), at p. 1. These reports are available at https://emp.lbl.gov/sites/all/files/lbnl-188238_1.pdf and https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report.pdf.

[25] LBNL, *Tracking the Sun VIII* (August 2015), data for Figures 19 and 20, and *Tracking the Sun IX* (August 2016), data for Figures 18 and 19.

[26] Towns in New Hampshire can offer property tax exemptions or reductions for solar systems, and about 50% do. See https://www.nh.gov/oep/energy/saving-energy/documents/dra-solar-exemption-report.pdf and https://www.nh.gov/oep/energy/saving-energy/documents/solar-repte.pdf.

Table D-14: *Key Assumptions for the Residential Cost of Solar*

Assumption	Value
Median Cost	$3.60 per watt DC
Range of Costs (20th to 80th percentiles)	$3.20 - $4.50 per watt DC
Federal ITC	30%
State incentive	$0.50/watt-AC, up to $2,500
Financing Cost	3%
Participant discount rate	5%
Financing Term	12 years
Property taxes	1% of original cost
Inverter Replacement	$700/kW in Year 15
Maintenance Cost	$26 per kW-year

The assumptions for the levelized costs of small commercial systems are similar, with the addition that commercial systems qualify for accelerated depreciation and are subject to different tax treatment as businesses. **Table D-15** shows the resulting levelized costs of solar energy ("Solar LCOEs") for residential and small commercial customers.

Table D-15: *Summary of Solar LCOEs (25-year levelized $/kWh)*

Market / Installation Cost	Utilities		
	Eversource	Liberty	Unitil
Residential	*53%*	*74%*	*73%*
Median	0.176	0.183	0.163
20th Percentile	0.159	0.165	0.148
80th Percentile	0.213	0.221	0.198
Commercial	*47%*	*26%*	*27%*
Median	0.146	0.149	0.140
20th Percentile	0.141	0.144	0.136
80th Percentile	0.154	0.157	0.147

3. Bill Savings for Participants / Lost Revenues for Non-participating Ratepayers

A primary benefit of solar DG for the customers who install it are the savings that they realize on their utility bills, as a result of the retail rate credits provided through net metering. At the same time, these bill savings also are the primary costs of net metering for non-participating ratepayers, because they are the revenues that the utility loses as a result of DG customers serving their own load.

We have modeled the long-term bill savings that solar customers will realize under the principal residential and small commercial rate schedules for the three utilities. We have modeled the savings assuming a solar system sized to serve 80% of the customer's annual usage, although for most schedules the assumed system size does not have a strong impact on the bill savings. The savings decline over time due to the 0.5% annual degradation in solar output. For the default supply rate, we have developed a model of future default supply rates by analyzing the recent observed relationship between these rates and LMP and capacity market prices in New Hampshire, and then applying this relationship to our forecast of avoided energy and generation capacity prices. In this way, our bill savings and avoided cost benefit models use consistent escalation rates. We assume that the remaining components of utility rates will escalate with inflation.

The current mix of residential and commercial systems installed in 2015 for all three utilities, by installed PV system capacity, is 56% residential and 44% commercial. The share of commercial systems in Eversource's territory (47%) is much higher than for the two smaller utilities (26% and 27%). We assume that this distribution of residential and commercial systems will continue. With this mix, the average levelized bill savings across both the residential and commercial markets is about 15-17 cents per kWh, as shown in the table below.

Table D-16 summarizes the modeled bill savings / lost revenues for the residential and commercial customers of the three utilities.

Table D-16: *Bill Savings / Lost Revenues (25-year levelized $/kWh)*

Market	Utilities		
	Eversource	**Liberty**	**Unitil**
Residential			
Distribution of Systems	*53%*	*74%*	*73%*
Bill Savings / Lost Revenues	0.201	0.192	0.195
Commercial			
Distribution of Systems	*47%*	*26%*	*27%*
Bill Savings / Lost Revenues	0.151	0.140	0.157
Combined Residential and Commercial			
Distribution of Systems	*100%*	*100%*	*100%*
Bill Savings / Lost Revenues	0.177	0.179	0.184

4. Results of the Standard Practice Manual Tests

The tables above provide the three principal sets of benefits and costs necessary to apply the principal *Standard Practice Manual* tests to solar DG in New Hampshire:

A. **Table D-12**: avoided cost benefits of DG (benefits in the TRC and RIM tests)
B. **Table D-15**: LCOE of solar DG (costs in the TRC and Participant tests)
C. **Table D-16**: bill savings/lost revenues (benefits for Participants/costs in RIM test)

Table D-17 summarizes these benefits and costs, and shows the SPM test results for the residential and commercial markets separately, and for both markets combined. Please note that we show the final benefits and costs in 25-year levelized cents per kWh.

Table D-17: *Standard Practice Manual Test Results*

Cost or SPM Test	Utilities		
	Eversource	Liberty	Unitil
Residential	*53%*	*74%*	*73%*
Costs *(25-year levelized cents/kWh)*			
A1. Direct Avoided Cost Benefits	20.6	20.0	19.6
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	17.6	18.3	16.3
C. Bill Savings / Lost Revenues	20.1	19.2	19.5
SPM Test Results			
TRC – A1 ÷ B	**1.17**	**1.09**	**1.20**
Societal – A2 ÷ B	**1.73**	**1.63**	**1.80**
Participant – C ÷ B	**1.14**	**1.05**	**1.19**
RIM – A1 ÷ C	**1.03**	**1.04**	**1.01**
Commercial	*47%*	*26%*	*27%*
Costs *(25-year levelized cents/kWh)*			
A1. Avoided Cost Benefits	20.6	20.0	19.6
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	14.6	14.9	14.0
C. Bill Savings / Lost Revenues	15.1	14.0	15.7
SPM Test Results			
TRC – A1 ÷ B	**1.41**	**1.34**	**1.40**
Societal – A2 ÷ B	**2.08**	**2.00**	**2.09**
Participant – C ÷ B	**1.03**	*0.94*	**1.12**
RIM – A1 ÷ C	**1.37**	**1.42**	**1.25**
Combined Residential & Commercial	*100%*	*100%*	*100%*
Costs *(25-year levelized cents/kWh)*			
A1. Avoided Cost Benefits	20.6	20.0	19.6
A2. Societal Avoided Cost Benefits	9.8	9.8	9.7
B. LCOE of Solar for Participants	16.2	17.4	15.7
C. Bill Savings / Lost Revenues	17.7	17.9	18.4
SPM Test Results			
TRC – A1 ÷ B	**1.27**	**1.15**	**1.25**
Societal – A2 ÷ B	**1.88**	**1.71**	**1.87**
Participant – C ÷ B	**1.10**	**1.03**	**1.17**
RIM – A1 ÷ C	**1.16**	**1.12**	**1.06**