EXHIBIT
41
DE 16-576

STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

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

REBUTTAL TESTIMONY OF

ASHLEY C. BROWN

ON BEHALF OF

UNITIL ENERGY SYSTEMS, INC.

December 21, 2016

Contents

INTRODUCTION

Q. On whose behalf are you testifying?

A. On behalf of Unitil Energy Systems, Inc.

Q. What is the purpose of your testimony?

A. To rebut certain inaccurate claims and arguments made by witness Mr. R. Thomas Beach, on behalf of The Alliance for Solar Choice, witness Mr. Patrick Bean, of SolarCity, on behalf of the Energy Freedom Coalition of America, witness Mr. Nathan Phelps, on behalf of the New Hampshire Sustainable Energy Association, and witness Mr. Paul Chernick, on behalf of the Conservation Law Foundation.

Q. Please describe your background and qualifications.

A. I am the Executive Director of the Harvard Electricity Policy Group (HEPG) at the Harvard Kennedy School, at Harvard University. HEPG is a "think tank" on electricity policy, including but not necessarily limited to pricing, market rules, and regulation, as well as environmental and social considerations. HEPG, as an institution, never takes a position on policy matters, so this paper represents solely my opinion, and not that of the HEPG or any other organization with which I may be affiliated. Prior to coming to Harvard, I served 10 years (two full terms) as Commissioner of the Public Utilities Commission of Ohio. During my tenure, I also served as Chair of the NARUC Committee on Electricity, as a member of the Board of the National Regulatory Research Institute, and as a member of the Advisory Board of the Electric Power Research Institute. I am also the co-author of the World Bank's *Manual for Evaluating Infrastructure Regulation*. My full biography is attached as Appendix A.

Q. What is the general outline of your testimony?

A. New Hampshire HB 1116 has required the initiation of a proceeding to develop alternative net energy metering tariffs, which should ensure that "costs and benefits are fairly and transparently allocated among all customers." The New Hampshire Public Utilities Commission has detailed a number of considerations for this proceeding, including the "costs and benefits of customer-generator facilities," "avoidance of unjust and unreasonable cost shifting," and "rate effects on all customers." Initial testimony submitted reflects considerable disagreement about what net energy metering is, what the costs and benefits of current net energy metering arrangements are, and what kind of tariff might be most "fair" and "transparent." The purpose of my testimony is to clarify some key areas of disagreement related to 1) pricing and why three part rates are especially appropriate for distributed generation customers and 2) costs and benefits of distributed solar, as described in HB 1116 (often described as "value of solar," or perhaps ascertainment of "avoided costs"), and why analyses that assign substantial non-energy values to distributed solar generation are seriously flawed. In what follows I review:

- Basic utility pricing principles, including the importance of external discipline on pricing and the three types of utility costs (fixed, variable energy, and demand);
- Retail net metering ("RNM"), its history, and the problems of RNM;
- Why claims about the "value" of solar do not justify RNM;
- How the specific analysis of the "value of solar" provided by Mr. Beach exemplifies the common problems of value of solar analysis and does not provide any justification for continuing the burdensome and unfair cross subsidies inherent to retail net metering.
- Why the three part rate proposed by Unitil can help address current inequities and inefficiencies of RNM.

I. BASIC UTILITY PRICING PRINCIPLES

Q. What basic pricing principles should be kept in mind in reviewing the testimony presented related to net metering in New Hampshire?

A. It is a fundamental principle of electricity pricing that prices should always be subjected to external discipline, either the discipline of market competition or, in the absence of meaningful competition, to the discipline of cost-based regulation. To the extent that the rates for distribution utilities cannot always be fully competitive, utility regulators use costs to establish reasonable rate limits. In his seminal 1961 book on utility ratemaking, the economist James Bonbright,[1] whose writings on the subject are widely regarded as authoritative, argued for the importance of a "cost of service" standard in setting rates.[2] Writes Bonbright:

> *[O]ne standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike—the standard of cost of service, often qualified by the stipulation that the relevant cost is* necessary *cost or cost reasonably or prudently incurred.*[3]

In implementing "cost of service" ratemaking, ratemaking bodies typically follow a two-step process: 1) determining the utility's total costs—including a fair rate of return on capital investments, and 2) setting rates by allocating a share of those costs to different classes of customers and then selecting rate structures to recover sufficient revenue from each class of customer.

Q. Are there different types of costs that utilities face and that should be considered separately in ratemaking?

A. Yes. The three most important types of costs for electric utilities are 1) variable energy costs: the total number of kilowatt hours (kWh) used; 2) demand costs: the total capacity

[1] Bonbright, who died in 1993, was a long time member of the Business School Faculty at Columbia University and served for some time as Chairman of the New York Power Authority. He is widely regarded as one of the nation's most distinguished writers and commentators on regulations and a most important thought leader on the subject.

[2] This view is generally held by others as well. *See, e.g.*, https://mitei.mit.edu/system/files/Electric_Grid_8_Utility_Regulation.pdf.

[3] Bonbright, *op cit*, p. 67.

(kilowatts, or KW) the utility must build and maintain in order to meet peak demand—generation, transmission, and distribution adequate to supply all the power needed at the moment of the very highest demand (keeping in mind that the obligation to serve is unlimited); and 3) fixed costs: costs that must be incurred regardless of kWh or KW, and which do not vary with demand. Fixed costs are typically thought of as costs that are unaffected by individual customers' changes in energy consumption. Examples include the costs of customer service and billing.

Q. How have these three types of costs typically been reflected in rates?

A. For residential customers, those three separate kinds of costs have traditionally been bundled together into two-part rates, consisting of a monthly fixed charge and an energy charge (based on total kilowatt hours used). In a two-part rate, "Demand" costs (that is, capacity costs associated with meeting peak demand) are lumped in with the energy charge, rather than being shown separately in the bill—so, effectively, customers who use more kWh during a month pay a correspondingly greater share of demand costs. This results in rough conformity with the "cost causer pays" principle, as long as kWh usage and peak demand (KW) vary together. In addition, the fixed charge on the bill of a residential customer represented only a tiny fraction of the totality of the fixed costs. Thus, the bulk of the fixed costs and all of the demand costs were recovered through volumetric based rates (i.e. on a per kwh basis).

Commercial and industrial (C&I) utility customers, in contrast, have long been subject to three part rates, corresponding with the three types of utility costs. Thus, rates for a commercial or industrial customer typically include a fixed charge and two variable charges—an energy charge, based on total kilowatt hours used, and a demand charge, based on how much capacity the utility needs to maintain to meet the customer's peak demand (measured in kilowatts).[4] Accordingly, C&I customers are not only positioned to reduce both system costs and their own costs by getting a discrete demand price signal, but by providing that signal, new market entrants with the capability of managing demand costs could enter the market and provide such services.

II. RETAIL NET METERING (RNM), ITS HISTORY, AND THE PROBLEMS OF RNM

Q. What were the origins of RNM?

A. The initial connection of rooftop solar systems to the grid posed an issue for utilities and regulators. If customers supply power to the grid, how should they be compensated? When rooftop solar systems were first connected to the grid in the 1980s and 1990s, most households had a single meter capable only of running forwards, backwards, and standing still, and utilities and regulators had limited options. Given the very limited amount of rooftop solar market penetration anticipated at the time, and the high cost of rooftop solar, large scale investment in new technology or overall tariff reform was not a priority.[5] Many utilities adopted retail net metering. Under a RNM tariff, a single meter for these customers runs forward when solar PV DG customers are purchasing energy from the grid. When those customers produce energy and consume it on premises, the meter simply stops, and when the customer produces more energy than is consumed on premises, the meter runs backwards as the excess energy is exported to the grid. Thus, the solar PV DG customer pays full retail price for all energy taken off the grid, pays nothing for energy or fixed costs such as distribution, transmission, generating capacity, or

[4] It is interesting that when talking about the forces that likely would prompt a utility to adopt a demand charge for industrial customers, Bonbright calls out distorting effects caused by industrial customers who provide some of their own generation. (Bonbright, pp. 309-311)

[5] Indeed, some utilities, trying to avoid the issue altogether, simply refused to interconnect rooftop solar units to the grid at all.

demand costs when energy is being produced on premises, and is credited the fully delivered retail price (i.e., all energy plus all fixed costs, despite the fact that solar customers incur no such fixed or demand costs) exported into the system. At the end of whatever period is specified, the meter is read and the customer either pays the net balance due or the utility credits the customer for excess energy delivered.

Under RNM, therefore, customers produce energy, but are compensated at rates that reflect the full cost of generation and of transmission and distribution. This generous arrangement seemed to make sense originally, at a time when market penetration of rooftop solar was negligible, when rooftop solar systems were far more expensive than they are today, when metering technology was relatively primitive, when wholesale energy and capacity markets did not generate the very sophisticated and unbundled signals they do today, and when the amount of fixed and demand costs that would be bypassed by widespread deployment of rooftop solar were unknown. To the extent that any policy considerations contributed to its adoption, it was that RNM would provide a short-term stimulus to the development of distributed solar technology, at that time a very expensive product. It was never intended to be a long term pricing methodology.[6] The notion was that RNM would serve as a short term stimulus to boost rooftop solar into commercial viability.

Q. Does the original rationale behind the adoption of RNM still apply today?

A. No. Today, the technological limitations that were a primary driver of current net metering policies and tariffs have largely disappeared. "Smart meters," as well as

[6] While the full effects of retail net metering were unknown at the time of their adoptions, many jurisdictions, just to be cautious about the unknown, actually hedged against severe distortions by capping the amount of rooftop solar and/or sizes of units that would be on an RNM tariff. A 1996 overview of state net metering programs prepared by NREL found that almost all included individual capacity limits, while three states (including New Hampshire) also had statewide capacity limits. *See* Yih-hui Wan, *Net Metering Programs*, NREL Topical Issues Brief (December 1996), Table 1, p. 3. Available online at: http://www.nrel.gov/docs/legosti/old/21651.pdf

internet-based technology, are capable of measuring not only how much electricity consumers use in a month, but when and even how they use it.

At the same time that smart meters have become widely deployed, the basic economics of solar panels have changed dramatically. The costs of solar panels have declined enormously. As I argue below, because of net metering, the full benefits of the declining costs are not being passed on fully to customers (solar and non-solar alike)—indeed, the fact that the costs of rooftop solar panels are significantly lower than they were when regulators initially settled on generous retail net metering schemes as a way of providing a short term boost to enable rooftop solar to attain full commercial viability is a clear demonstration of the fact that such cross-subsidies are now neither necessary nor desirable. In fact, they may well serve as an impediment to the full commercial viability for rooftop solar that is desirable. Now that the costs of rooftop solar have declined, that short term stimulus rationale for tolerating the flaws of net metering no longer applies. Stated succinctly, the underpinnings of net metering: dumb meters, poor energy price signals in the wholesale market, miniscule market penetration by distributed resources, and out of market costs, are all historical relics that decidedly not characteristic of 21^{st} century electricity markets

Q. What's wrong with retail net metering?

A. The fundamental problem with retail net metering (which is at the root of many other issues) is that under retail net metering, the connection between costs of service to the customer and the price paid by the customer is lost. Through RNM, solar customers have until recently had the same residential tariffs applicable to them as were applied to non-solar residential customers (adapted, of course, to give credit for solar production). However, by the standards of cost-based ratemaking, traditional residential tariffs (i.e., volumetric rates based on kWh, and encompassing charges related to generation, transmission, and distribution), when applied to customers with solar generation, do a markedly worse job of reflecting actual customer costs than they do when applied to other customers.

This breakdown of the relationship between costs and rates has four main consequences:

- Cross subsidies. Distributed generation customers are undercharged for their usage, and end up subsidized by customers without distributed generation;
- Inefficiency. Distributed generation customers do not receive price signals that would encourage them to maximize the value of the solar energy they produce; at the same time, the distributed solar industry, shielded from market pressures, fails to maximize efficiencies and savings to customers;
- Unfairness to competing technologies; and
- Undermining the prospects for the long-term sustainability of rooftop solar energy, due to a lack of incentives for productivity gains and inflating prices well above underlying costs.

Q. Why do you say that one consequence of RNM is a cross subsidy?

A. As discussed above, traditional rate plans, including New Hampshire's existing Net Energy Metering plans, use volumetric rates to recover not only variable costs such as fuel, but also a very substantial part of the fixed and demand costs (transmission and distribution, as well as capacity components of generation). Customers who generate their own energy may purchase less energy from the system, but the fixed costs of service still exist, and, due to both intermittency and non-coincidence with peak demand, the demand costs are also largely unabated.[7] The result of linking RNM with a purely volumetric rate structure that makes no distinction between generation energy and

[7] For a view of size and scale of the cross subsidy, see Rethinking Rationale for Net Metering | Fortnightly, by Barbara Alexander, Ashley Brown, and Ahmad Faruqui. (www.fortnightly.com/fortnightly/2016/10/rethinking-rationale-net-metering)

capacity costs as well as distribution and transmission costs constitutes a substantial cross-subsidy to rooftop solar customers. The costs of that subsidy are borne by the utility's non-solar customers.[8]

This subsidy does not exist for most residential customer classes. This is because most customers' peak demand (measured in KW) and overall kWh usage typically vary together. (This is true for customers who invest in energy efficiency, as well as other customers). For solar DG customers, however, the traditional relationship between peak demand (KW) and overall kWh usage breaks down. Solar customers can reduce their kWh usage by a lot (especially if they get credit for excess kWh produced) while only slightly, if at all, reducing their peak demand (it is even possible demand could be increased, if solar customers are motivated by their reduced bills to consume more electricity overall).[9]

The fact that customers with rooftop solar may produce energy when the sun is shining does nothing to reduce the utility's fixed per-customer costs and, at least in the short run, has not been reliably shown to reduce the capacity costs the utility must incur in order to make sure that it is prepared to meet all of the electric requirements of the solar customers at all times, including when their panels are either producing insufficient energy to meet all or a portion of their requirements. Indeed, the intermittency of solar means that there must be sufficient capacity to meet demand even at times when one

[8] The cross-subsidy discussed in my testimony relates solely to those embedded in utility rates. What is not being discussed in this testimony but must be considered in the overall policy context is that rooftop solar is already heavily subsidized by substantial tax credits, renewable portfolio standards, renewable energy credits, and, perhaps, other programs that are also beyond the jurisdiction or control of utility regulators. Thus, any decision by the Commission to alter net metering will not have the effect of leaving rooftop solar without substantial governmental intervention in the marketplace in its favor. What regulators are deciding is how to send the appropriate price signals for rooftop solar to be deployed in the most cost effective, socially beneficial, and environmentally desirable way, not whether public subsidies should be available.

[9] For an example, see the testimony of H. Edwin Overcast in this case. Table 1 on page 19.

might expect solar panels to be producing energy. Thus, when solar DG customers are producing energy and not buying it, the utility only offsets its energy costs, but cannot offset its fixed costs by simply buying or producing less energy. Thus, the utility has a revenue shortfall, which will inevitably be passed on to non-solar customers.

Q. What is your response to claims that rooftop solar offsets capacity costs, not just energy costs?

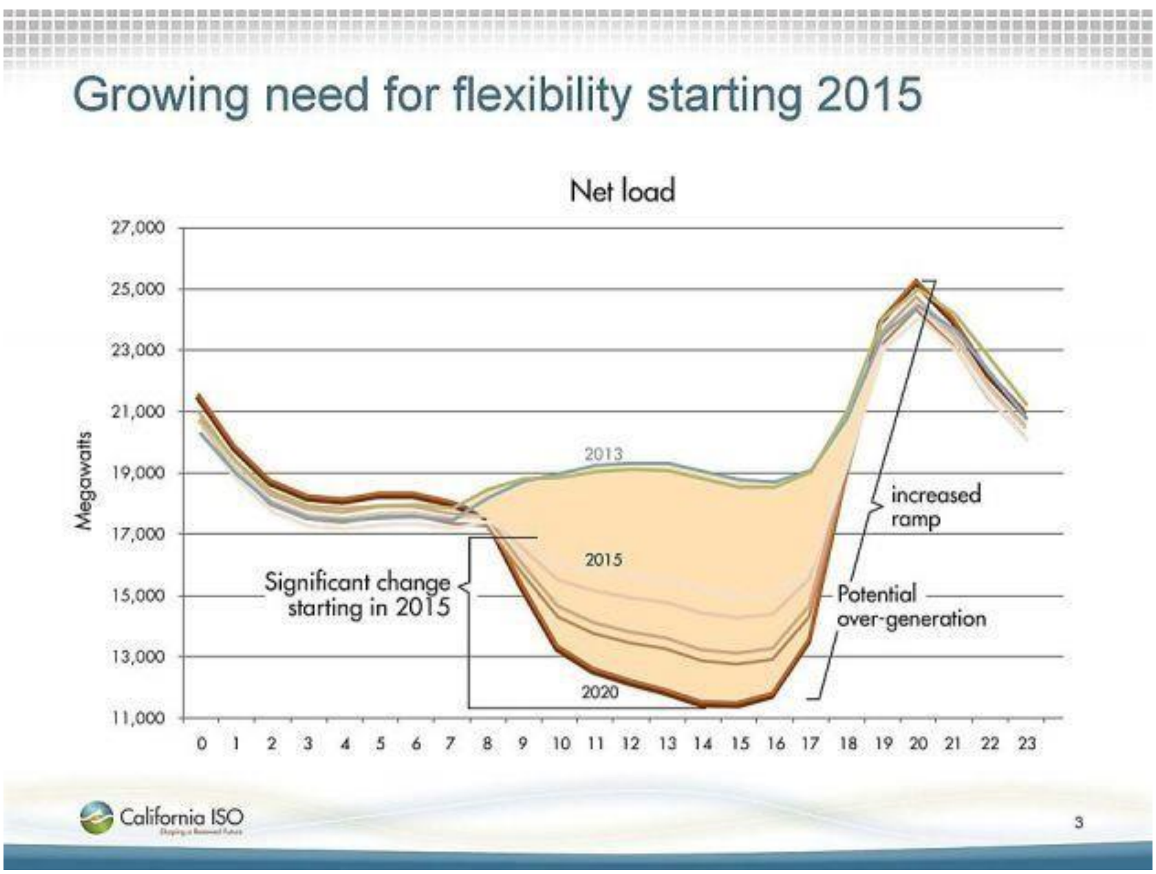
A. Rooftop solar generation does not appreciably offset a utility's capacity costs for two very basic reasons. The first is that solar production is, with some occasional exceptions, not coincident with system-wide peak demand.[10] The second reason is that, even if solar production generally matched the time when demand was projected to be at its peak, solar production is intermittent, indeed, unpredictably so,[11] and thus not dispatchable by the grid operator (i.e., the grid operator cannot call upon it to produce to meet peak demand, or stop producing when there is cheaper, excess capacity on the system). For a utility legally obligated to meet all of the electricity demand of customers in their service territory, the existence of rooftop solar therefore does little to avoid the need to incur the costs of meeting all demand and, in effect, providing "battery" service to solar customers. The question before the Commission is who is obligated to pay for this "battery," the

[10] As can be seen below, in the charts from ISONE on "Seasonal variation in load profiles," there is zero overlap between solar production in spring and winter. Summer shows a limited amount of overlap, which diminishes with greater levels of solar penetration. In New England, wholesale electricity prices are higher during the winter, so this means solar is not offsetting peak energy costs during the most expensive time of year. (See ISONE, 2016 Regional Electricity Outlook, p. 23, at **https://www.iso-ne.com/static-assets/documents/2016/03/2016_reo.pdf)** As the testimony of H. Edwin Overcast in this case confirms, New Hampshire is no exception here—there is only a minimal overlap between solar production and peak demand. (Overcast testimony, p. 20).

[11] It is important to note that rooftop solar is a double contingency intermittent energy source. It not only depends on the presence of the sun, but also on how much of the energy being produced is consumed on premises by the solar host and is never exported into the system. That constitutes a notable contrast with utility scale solar, which is a single contingency intermittent resource.

solar customers for whom the costs were incurred, or other customers, who had nothing to do with causing "battery" costs to be incurred?

In fact, rooftop solar production generally creates a new and challenging daily variation in the net load that must be served by the utility, a pattern that has come to be known as the "duck curve." Briefly stated, the "duck curve" refers to the phenomenon by which rooftop solar generates large amounts of power in the middle of the day, but as solar production declines throughout the afternoon, the corresponding increase in demand must be met by other generation supplied or procured by the utility.[12] The "duck curve" phenomenon is illustrated in the chart below (drawn from California), in which the belly of the duck shows the increasingly steep drop off and ramp up of net load that is occurring and expected to increase with greater adoption of solar generation:



[12] **http://instituteforenergyresearch.org/solar-energys-duck-curve/**; https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

As is dramatically illustrated in the graph, enticed by a number of factors, not the least of which is net metering, substantial investment in the growth of solar capacity in California has enormously magnified the need for additional fossil plants, operating on a ramping basis, to compensate for the drop off in solar production at peak. In that context, the absence of any meaningful signal to make solar more efficient (e.g. directing solar panels to the west, or linking solar production with storage) is simply something that can no longer be tolerated.[13] While New Hampshire's situation is certainly not identical to California's, it would be pure folly for the state not to learn the lesson of what has been problematic in a state with heavy solar DG market penetration, and adopt an approach that averts a similar dilemma.

Intermittent sources of generation add additional complexity and cost to maintaining the high degree of reliability expected from the system. This is particularly true because the grid was originally designed to accommodate one-way delivery of electricity, not the two-way exchange associated with rooftop solar generation.[14] Thus, when rooftop solar penetration increases beyond minimal levels, new investments to the grid are required.[15]

[13] For further discussion of the implications of the duck curve, see *What the duck curve tells us about managing a green grid*, CAISO, 2013 (http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.)

[14] The two way flow, particularly since the energy inputs to the distribution system are from diverse and unpredictable places, can fundamentally alter grid dynamics by impacting on such critical elements as voltage support and reactive power. Since location of solar units can be a critical element in how these grid phenomena play out, the inability to plan locations for solar dg, almost inevitably drives up utility costs in accommodating distributed solar.

[15] **https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf** at xviii.

Maintaining reliability on a distribution system, particularly where market penetration of rooftop solar has increased significantly, is far more than an engineering challenge. It requires a substantial investment in more modern control and monitoring technology, as well as a substantial rethinking of pricing and the incentives produced from the economic signal produced, in order to move the entire system in directions that will best accommodate all of the changes in the power sector, particularly those related to the increasing deployment of intermittent generating facilities. The complexities associated with solar DG are further compounded by two additional factors. The first is that the locating of solar units is unplanned, and, from a planning perspective, random. That being the case, it is impossible to optimally locate panels to capture system benefits. As long as solar panels are sold or leased on a geographically unplanned basis, there is almost no likelihood that system costs will be systematically reduced by distributed solar. Secondly, distributed solar generation is unseen by ISO New England and is, therefore, not dispatchable. That effectively eliminates the possibility that solar DG makes any contribution to the efficiency of dispatch, enhancement of distribution services, or of the overall energy market in New England.[16]

In the face of concerns about additional ramping and other system management costs required to respond to the new demand patterns created by the adoption of more solar energy, and of cross-subsidies between customers resulting from retail net metering rates, some advocates of RNM call for "value of solar" analyses, in order to claim that additional non-energy attributes of distributed solar generation add substantially to the

[16] In fact, witness Mr. Bean references the same issues regarding the lack of planning for distributed solar resources. Indeed, his discussion of those issues directly contradicts the dismissal of those issues by Conservation Law Foundation witness Mr. Chernick as well as the broad claims of value added by solar DG made by Mr. Beach. In essence, Messrs. Chernick and Beach are proposing that solar DG be compensated for services that Mr. Bean effectively conceded may not be provided in the absence of a planning process that currently does not exist.

value provided by solar DG to the utility and other customers. As a result, they argue, concerns about cross-subsidies to solar customers are misplaced. These arguments are discussed in more detail below. However, in order to believe that such cross subsidies among customers are cancelled out by the "value of solar," one would need to believe that the "value of solar" supplied is, ascertainably and quantitatively, worth an amount well in excess of the price of energy in the wholesale market at the time the energy is produced, and, in the case of the Maine Value of Solar study, more than double the delivered price of electricity. I discuss in more detail below why this is simply not credible.

Q. So, what do you conclude from this about whether cross-subsidies result from RNM?

A. The result of the re-allocation of the responsibility for costs is that net metering results in a subsidy from customers without rooftop solar systems to those with solar. These subsidies associated with RNM are particularly hard to defend because, in the aggregate, they benefit wealthier customers at the expense of less affluent customers.[17] Less affluent customers lack the means to invest in solar and often do not own their residences, so they are unable to install solar, even if they could afford to do. This gap is exacerbated by the practices of rooftop solar providers like SolarCity, which offer a lease mode for customers without the cash to buy a whole system up front—but the lease product is only available to customers who meet stringent credit requirements.[18]

[17] It is curious that the socially regressive nature of RNM is not identified in any of the cost/benefit considerations of the pro net metering witnesses in this proceeding. It is another example of the cherry picking they engage in in offering up their value of solar contentions.

[18] The idea of lowering credit requirements was raised by SolarCity, but there are no immediate plans for doing so: http://www.reuters.com/article/us-solarcity-fico-idUSKCN0T82ZO20151119.

In addition, RNM encourages rooftop solar providers to "cherrypick" high-income, high-energy usage customers. A 2013 study by E3 Consulting clearly shows the socially regressive impact of net metering. The study found that the median income of rooftop solar customers under RNM was 168% of the median California household income.[19] A similar analysis of rooftop solar customers in California by Severin Borenstein also found installations, despite some decline in social regressivity recently, "heavily skewed towards the wealthy."[20] The Massachusetts DPU only recently made an explicit finding that costs of incentives for on-site generation, such as net metering, disadvantaged the poor and gave the state's low income customers explicit relief from having to subsidize solar DG customers in Massachusetts: "…low-income customers have experienced an increase in bills as a result of the growth of on-site generation."[21]

Q. Are there other negative consequences of RNM?

A. Yes. As I mentioned above, other negative consequences that spring from RNM are inefficiency, unfairness to competing technologies, and undermining the long-term prospects of rooftop solar itself.

Q. Why do you say that RNM leads to inefficiency?

A. RNM encourages inefficient behavior, both on the part of individual customers and the rooftop solar industry as a whole. For individual customers, RNM (especially in conjunction with a flat rate that does not vary with time of day or peak energy demand) fails to provide any incentive to maximize the value (as opposed to the output) of their

[19] *California Net Energy Metering Ratepayer Impacts Evaluation.* Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 8, 2013).

[20] Borenstein, Severin. "Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives and Rebates." Energy Institute at Haas Working Paper. 2015: 26. Paper available online at http://ei.haas.berkeley.edu/research/papers/WP259.pdf.

[21] See D.P.U. 15-155, September 30, 2016 at p. 470: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-155%2f15155_Order_93016.pdf.

rooftop solar systems. RNM customers with distributed solar are motivated to produce as many kWh as possible, but not necessarily to target production or manage demand to offset peak consumption.

One example of this problem has to do with the orientation of rooftop solar panels. The monetary value of energy provided to the grid by rooftop solar panels varies depending on the time of day. Generally speaking, energy provided at the time of peak usage is the most valuable. That is because the generating fleet is dispatched on the basis that the least expensive plants are generally dispatched first. As demand increases, more and more expensive plants are dispatched until all demand is met.[22] However, RNM (in conjunction with flat, time-invariant rates) provides one signal to customers with solar DG systems—the more you produce, the more you are paid, regardless of the energy market prices at the time of production.[23] For this reason, as a *New York Times* article explains, flat RNM pricing has contributed to solar panels generally being installed facing south, to generate the largest total quantity of solar energy over the course of the day (and the greatest savings and/or revenue for homeowners under RNM). If solar rates instead reflected the cost to the grid of the customer's period of highest demand, these panels would be adjusted to capture the most sun during peak hours—for many customers, this would mean aligning panels to face west, generating less total energy, but capturing the late afternoon power of the setting sun.[24] Thus, a customer who works

[22] It is worth noting that, in general, the economic order to dispatch power plants also has a salutary environmental effect. That is because, in general, the least expensive plants are either non-emitting of pollutants (e.g. renewables), or low emitting, more efficient plants.

[23] Energy prices in the electricity market, as one might expect when supply and demand have to be instantaneously matched, vary widely over the course of every day. Thus, the time at which energy is produced is a critical determinant of the price suppliers are paid. RNM ignores that market place reality and, under RNM, fetches an above market price for solar DG output that is exported onto the grid.

[24] Matthew L. Wald. "How Grid Efficiency Went South" *New York Times*. October 7, 2014.

outside the home and uses air conditioning in the evening during the hot summer months might well offset many (if not all) of his or her kWh of usage through robust rooftop generation—but still might impose a significant peak demand load on the grid when he or she arrives home at 6 or 7pm, when solar production is at or near zero, by turning on air conditioning and other electric appliances. In fact, the savings from solar electricity might even encourage such a user to use more peak electricity than he or she otherwise would—keeping the house a little cooler, or otherwise being more free with his or her energy use. Indeed, major solar installation company Solar City's own marketing materials, taking advantage of the lack of explicit and transparent demand cost price signals, promote this type of expensive, highly inefficient use of energy.[25] Thus, RNM incentivizes production in ways that are optimized for the rooftop solar industry and its customers, not to the system and non-solar customers.

Similarly, RNM discourages the adoption of batteries or other forms of storage in conjunction with rooftop solar production. This is because, under an RNM tariff, the utility operates essentially as a giant free battery available for use by DG solar customers—any excess energy they produce is credited back to them at the full retail price, and they can use this credit to import an equivalent amount of energy back from the grid at any time at the full retail price. While at first blush that might seem reasonable, it is not sustainable. Solar production is largely off peak, while substantial imports are required at peak by solar customers. The following three charts show the relationship in New England during different seasons of the year, at a range of different levels of solar penetration. They are copied from the ISO New England's webpage titled

[25] A SolarCity advertisement encourages just this behavior: "Go ahead," it reads. "Sleep with the lights on. Solar energy is limitless." **https://mobile.twitter.com/solarcity/status/731167148882690048.** This advertisement is particularly irresponsible because solar power is not generated at night.

"Solar Power in New: Locations and Impact,"[26] and illustrate that facile assumptions made that solar benefits include near-term reductions in peak generation are precisely that.[27]

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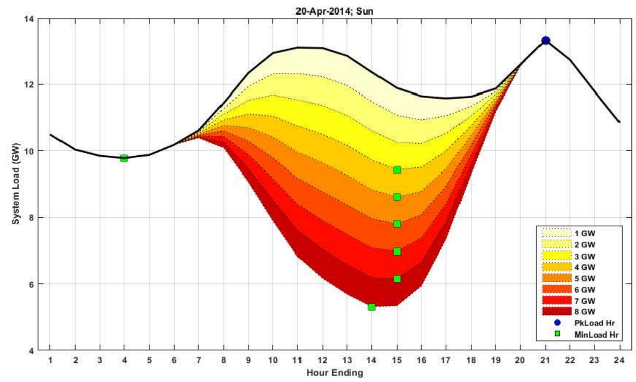
[26] Page can be found online at https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact

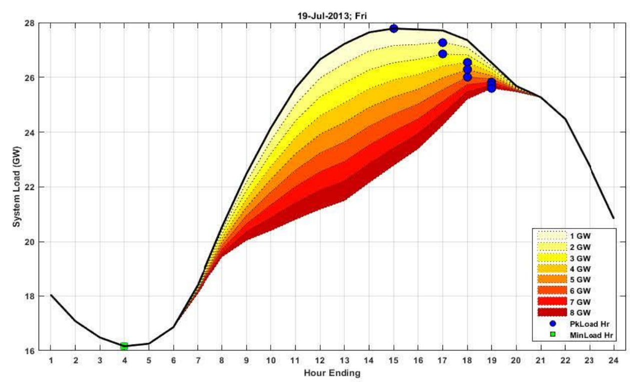
[27] Black, John. "Update on Solar PV and Other DG in New England." ISO New England (June 2013).

Seasonal variation in load profiles, ISONE

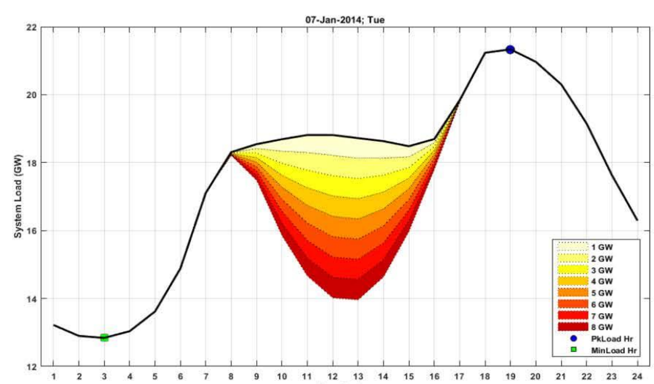
Spring



Summer



Winter



These three charts dramatically demonstrate that on the days chosen as representative of summer, winter, and spring in New England, solar PV peak and peak demand are not the same. Solar PV is completely absent during the winter peak and spring peak (however, it is interesting to note that winter solar production suggests the possibility of New England developing its own "duck curve.") During the summer, there is an overlap between solar production and peak demand, but, as can be seen on the chart, and as ISO New England explains in the accompanying text, "Because greater amounts of PV will actually shift the timing of peak demand for grid electricity to later in the afternoon or evening, PV's ability to reduce peak demand will actually diminish over time." It should also be noted that on the days chosen, the sun was shining. The graph, of course, would look very different on cloudy days when solar production is virtually nil.

Q. Why do you say RNM is unfair to competing technologies?

A. Technologies currently exist that could help customers with rooftop solar to manage their production and consumption so as to maximize the overlap between rooftop solar production and peak demand hours. Possible efficiency enhancers could include simply pointing solar panels to the west, rather than the south, but also using batteries to store off-peak energy, or smart thermostats to optimize energy usage patterns. However, under a flat RNM tariff, DG customers, who would seem to be a natural customer base for energy efficiency and/or capacity savings devices or storage batteries available on the market to better align their energy and capacity demand with system costs, have no incentives to invest in such products, therefore delaying the development of the integrated solar/battery home systems that may be a logical next step for distributed generation. That may be why, for example, Tesla—Solar City's own sister company, run by SolarCity's Chairman Elon Musk, which recently acquired Solar City—reportedly opposes RNM.[28] As this conflict makes clear, RNM removes an incentive for residential customers to deploy batteries and other forms of energy storage.

The failure to provide incentives to invest in efficiency-enhancing technologies points to another problem with RNM, which is that it distorts the competitive market for other resources. In seeking cost-effective means of reducing their electricity bills and environmental impact, consumers have a variety of options. Rooftop solar is one possibility, but there are a variety of competing alternatives; many of them provide greater value to the grid, and, absent rooftop solar subsidies, to the customer himself/herself, most notably various energy efficiency programs and means of flattening out their load profile.[29] The subsidies associated with RNM, however, substantially bias decisions in favor of rooftop solar over these other options, which would be more efficient, and, in the absence of subsidies, would be the most economic for the customer.

Rooftop solar is the most expensive form of commonly deployed renewable generation in the U.S. today. The latest annual update of Lazard's *Levelized Cost of Energy Analysis* continues to show this, with a levelized cost for rooftop solar ranging from $138-$222 per MWh, higher than all other energy sources analyzed (with the exception of a diesel reciprocating engine), including fuel cell, solar thermal, utility-scale solar, geothermal, biomass, and wind.[30] The Lazard analysis goes on to compare the cost of carbon abatement per ton for different alternative energy resources. As one would expect based on its levelized cost, rooftop solar power had the highest cost per ton of

[28] "Net Metering vs. Storage Creates Clash Between Some Allies." http://www.eenews.net/stories/1060025111

[29] Load profile is the configuration of how much energy a customer consumes (in kilowatt hours (kWh)) and precisely when it is consumed. The time when the demand hits its maximum defines the amount of capacity (in kilowatts (KW)) a utility must have available to serve that customer.

[30] *Lazard's Levelized Cost of Energy Analysis-Version 10.0.* December 2016. Data cited is from p. 2 table, "Unsubsidized Levelized Cost of Energy Comparison." Full report available online at https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf

carbon emissions avoided ($176 per ton, assuming gas is the comparison generation). In contrast, Lazard's calculations found that utility-scale solar PV could abate the same ton of carbon emissions at a cost of only $1 per ton. The difference here is staggering. [31]

A recent study by the Brattle Group comparing generation costs of utility-scale and residential-scale PV in Colorado confirms that most of the environmental and social benefits provided by PV systems can be achieved at a much lower cost at utility-scale than at residential-scale."[32] RNM, however, operates to make rooftop solar more attractive than other forms of renewable generation via subsidies from non-solar ratepayers, diverting resources away from competing (and, arguably, superior, technologies).

Q. Why do you say RNM undermines the long-term potential of rooftop solar as a competitive energy technology?

A. RNM fails to pass on the benefits of the declining costs of solar panels to consumers. The effect of RNM is such that the generous subsidies inherent in the price paid for the energy sold reduces the discipline imposed by having to compete with other energy sources. The result is that the vendors on whom the cross-subsidies are bestowed are relieved of competing for business based on prices and productivity, and are enabled to retain most, if not all, of the benefits of declining costs for themselves rather than passing them on to consumers. In effect, the price of rooftop solar is higher than a competitive market would allow it to be. RNM effectively inflates the price above levels justified by cost or market and reduces the price attractiveness of rooftop solar by extracting dollars from solar customers. This market distorting reality has been shown in recent research.

[31] *Lazard's Levelized Cost of Energy Analysis*-*Version 10.0*. Data cited is from p. 6 table, "Cost of Carbon Abatement Comparison." Full report available online at https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf

[32] Bruce Tsuchida, Sanem Sergici, Bob Mudge, Will Gorman, Peter Fox-Penner, and Jens Schoene, "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area." The Brattle Group, July 2015, p. 3.

The MIT study, *The Future of Solar Energy*, observes a "striking differential" between MIT's estimate of the cost of installing residential PV systems (even allowing for a profit margin) and the reported average prices for residential PV systems—actual prices for residential systems were approximately 150% of MIT's cost estimate—a difference between cost and price the MIT researchers did not observe for utility-scale installations.[33] Indeed, as documented in the MIT study, there is evidence now that the declining costs of solar panels, which have been quite dramatic in recent years, are not being passed through to consumers, enabling most of the benefits of declining panel costs to be retained by solar vendors, to the detriment of all consumers, solar and non-solar alike.

A recent study by Lawrence Berkeley National Labs found that out of four countries it compared to the U.S. (Germany, Japan, France, and Australia), the U.S. had the highest prices (per watt of capacity) for installed residential PV systems.[34] The reasons for these high U.S. prices are not fully understood—it is something more than market size, since the U.S. market is smaller than the solar pv market in some of the four other countries studied, but larger than others. A 2014 study aimed at better understanding variations in solar pv pricing, involving collaboration between researchers from Yale, Lawrence Berkeley National Laboratory, the University of Wisconsin at Madison, and the University of Texas at Austin, found a revealing association:

> "…regions with a higher consumer value of solar, considering retail electricity prices, solar insolation levels, and incentives, tend to face higher prices. This phenomenon may be the result of a shift in consumer demand caused by the presence of rich incentives, enabling entry by higher-cost installers and allowing for higher-cost systems. Alternatively, the results may be a symptom of high information search costs or otherwise imperfect competitions, whereby installers in these markets are able to "value price" their systems, effectively retaining some

[33] MIT, *The Future of Solar*, p. 86.

[34] Barbose, Galen and Naim Darghouth. Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States. Lawrence Berkeley National Laboratory (August 2016):22-23.

> portion of the incentive offered…In the short-run at least, policies that stimulate demand for PV may have the exact opposite of their intended effect, by causing prices to go up rather than down."[35]

That is, RNM, by effectively shielding rooftop solar suppliers, from both robust competition and from cost-based regulation, may be removing a key incentive for rooftop solar installation companies to pass on declining costs to customers.[36]

In fact, emphasizing this very point, in a recent 10K filing, SolarCity, the nation's largest solar DG company, clearly describes this as its business model:

> "We compete mainly with the retail electricity rate charged by the utilities in the markets we serve, and our strategy is to price the energy and/or services we provide and payments under MyPower below that rate. As a result, the price our customers pay varies depending on the state where the customer is located and the local utility. The price we charge also depends on customer price sensitivity, the need to offer a compelling financial benefit and the price other solar energy companies charge in the region. Our commercial rates in a given region are also typically lower than our residential rates in that region because utilities' commercial retail rates are generally lower than their residential retail rates."[37]

From Solar City's perspective, of course, the issue is not whether rooftop solar can be competitive, but whether it can remain so without suppliers like Solar City having to pass on to consumers some of the cost reductions in their supply chain, something that might reduce their profit on a per transaction basis, but make solar more attractive to more customers enabling more sales. In short, Solar City, the leading solar DG provider in the country, has a business model premised on keeping prices high in a declining cost

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[35] Gillingham, Kenneth, Hao Deng, Ryan Wiser, Naim Darghouth, Gregory Nemet, Galen Barbose, Varun Rai, and C.G. Dong. *Deconstructing Solar Photovoltaic Pricing: The Role of Market Structure, Technology, and Policy*. (December 2014): 20-21. Available online at: http://www.seia.org/sites/default/files/LBNL_PV_Pricing_Final_Dec%202014.pdf

[36] The failure to pass on declining input costs to customers is pricing behavior often considered to be characteristic of monopoly pricing.

[37] SolarCity Corp 10K, filed 2/24/15 for period ending 12/31/14, p. 38 (available at http://files.shareholder.com/downloads/AMDA-14LQRE/1445127011x0xS1564590-15-897/1408356/filing.pdf)

industry, and relying on subsidies and cross-subsidies in lieu of the classic economic formulation that lower prices (in this case enabled from lower costs) stimulate demand. Stated succinctly, the business model articulated by Solar City in its 10K filing, and shared by those solar DG vendors who demand retail net metering, is to chase subsidies and cross-subsidies rather than to compete in the marketplace.

This evidence of how major solar installers have a policy of setting prices to capture a maximum share of state incentives suggests that the arguments made by many advocates of continued RNM (for example, this argument is made by Mr. Patrick Bean in his testimony) that limiting DERs will contribute to higher electricity costs. There is no evidence for this—in fact, it is not even clear that lower subsidies for rooftop solar will make it less affordable for homeowners, though it will certainly reduce profit margins for solar installation companies.

III. WHY CLAIMS ABOUT THE "VALUE OF SOLAR" DO NOT JUSTIFY RETAIL NET METERING[38]

Q. Witness Mr. Beach and others assert that there are additional "values" provided by rooftop solar that make up for the cross-subsidy inherent in RNM. Does additional "value" provided by rooftop solar change the calculus in establishing rates for distributed generation/partial requirements customer?

A. No. In the face of opposition to the substantial cross-subsidies inherent in retail net metering, advocates of RNM, particularly commercial interests who benefit from it, have tried to develop theories as to why the obvious cross-subsidization either does not occur

[38] We do not price any other resource in electricity markets based on notions of "value." All other resources are priced by either competition in the marketplace, or based on costs. There is good reason for that. To illustrate what the power sector would look like if we deployed "value" pricing to the entire market, and why we do not use such pricing, I have attached Appendix B, which is an article, *The Value of Solar Writ Large*, which was recently published by The Electricity Journal.

in RNM, or in some cases have tried to contend that RNM actually constitutes a cross-subsidy from solar customers to non-solar ones. Their line of line of argument is based what has been described as "value of solar" theory, and it is a key area of contention in the testimony on this matter. As I argue below, "value of solar" analysis is inherently problematic, and "value of solar" numbers should be treated with extreme caution. In what follows, I address the following points:

- That "value of solar" harks back to a historically discredited model for pricing resources, which the experience with PURPA in the 1980s has demonstrated is inherently problematic, and that fails to consider the important question of whether claimed benefits can be supplied more cost effectively in other ways;
- That "value of solar" calculations, far from being definitive, are highly subjective, and there is no commonly accepted methodology for conducting such studies, so that not only is every input subject to debates, but there is not even any consensus on what the appropriate inputs are.
- That "value of solar" analyses tend to indulge in highly skewed identifications of benefits and costs;
- That a review of the common categories included in "value of solar" analyses show that, with the exception of energy value, most "values" are either imaginary, highly uncertain, arbitrarily fragmented, or more theoretical than real;
- In the case of New Hampshire specifically, as I will go on to explain in more detail, there are a number of significant problems with the analysis presented in *The Benefits and Costs of Distributed Solar Generation in New Hampshire* report (incorporated into Mr. Beach's testimony as Attachment D) that result in grossly inflated claims of "value" provided by distributed solar energy.

Q. Why do you say that "value of solar" is a historically discredited pricing model?

A. "Value of solar" pricing is an attempt to quantify the costs a utility avoids because of the deployment of rooftop solar generation. So-called "avoided cost" pricing has a history in utility regulation. In 1978, Congress enacted PURPA (the Public Utility Regulatory Policies Act). Among other things, PURPA encouraged the development of alternative power, including renewable energy and cogeneration, by requiring utilities to purchase energy and capacity from "qualifying facilities" (QFs) at their incremental or avoided costs. "Avoided costs" was defined as: "[T]he incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source."[39]

There are two fundamentally different methods that have been deployed to ascertain "avoided costs:" an administrative determination or a market based one. Most, if not all of the "value of solar" analyses, including the one conducted in New Hampshire, call for the use of administrative determination. Unfortunately, that methodology has a history that does little to recommend it.

After the passage of PURPA in 1978, efforts to calculate "avoided costs" rapidly encountered difficulties. As one article describing avoided cost pricing under PURPA observed:

> "Errors in the estimation of long-run avoided costs are inevitable. However, as PURPA was implemented by state regulators in the 1980s, a combination of questionable methods of setting avoided cost and/or poor application of these methods led to excessive avoided cost payments and forced utilities to buy QF capacity even when the utilities did not require more capacity. In addition, excessive, non-dispatchable QF output created operating problems for some utilities. Many complaints about PURPA's implementation were raised by electric utilities and others."[40]

[39] 18 CRF §292.101(b)(ii)(6) (Public Utility Regulatory Policies Act of 1978).

[40] Graves, Frank, Philip Hanser, Greg Basheda. "PURPA: Making the Sequel Better than the Original." Prepared for the Edison Electric Institute (December 2006).

The results of that experience of administratively determining avoided costs had severe consequences. In those states that, as the quote above suggests, came to inflated conclusions, the result was an oversupply of generation locked into long term contracts that were well in excess of market prices, thereby leaving utilities and their customers stuck with very high prices and stranded assets. The entire situation became so untenable that the FERC had to intervene and compel the states to use competitive mechanisms, rather than administrative means, to determine avoided costs and abandon the arbitrariness and methodologically suspect use of administrative mechanisms along the lines proposed by witness Mr. Thomas Beach and others in this proceeding. As someone who served as a Commissioner in the 1980's and early 1990's when the PURPA avoided cost debate was occurring, Mr. Beach's testimony is eerily familiar to me, as he advocates that we go down a path that we know from history will benefit a few favored developers, in this case solar pv vendors, in the short run, but leave everyone else stuck with a very big bill. As was clearly demonstrated by the PURPA experience, avoided cost analysis is subject to the biases and policy predispositions of the authors and/or sponsors of such studies.

Q. Does "Value of Solar" analysis incorporate any competitive metrics?

A. No, it most certainly does not. The methodology offered by Mr. Beach and advanced by other Value of Solar advocates makes no effort to ascertain whether the "values" supposedly provided by solar pv might be provided more cost-effectively in some other way. It simply states that they are provided by solar pv, and there is no competitive analysis of whether there are alternative ways of achieving the same results at a lower price. —Thus, there is no guarantee that customers are getting the best value. In fact, as discussed below, unlike in the classic PURPA avoided cost analysis, where the

Available online at
http://www.eei.org/issuesandpolicy/stateregulation/Documents/purpa.pdf

product/service being offered is, in fact, certain to be delivered, may of the values claimed by VOS advocates, such as Mr. Beach, are more theoretical than real, and in some cases are simply non-existent. Analyzing the "value" of rooftop solar in isolation produces an essentially meaningless number, in the absence of similar "value" analysis for all other competing resources and in the absence of assuring that the values claimed are actually delivered.[41] VOS studies are technology-specific (almost always limited to rooftop solar) and almost always ignore market conditions and how the calculated value of rooftop solar compares with the value of competing resources to meet the same objectives.

In addition, VOS studies rarely, if ever, look at the opportunity costs associated with spending money on rooftop solar, as opposed to using that money on something that provides any of the products and services being claimed for solar pv, such as energy, capacity, and/or emissions reductions more efficiently (many other major renewable technologies, as discussed above, beat rooftop solar by these measures). This kind of one-dimensional, out-of-context analysis of an extraordinarily complex subject is almost useless as an evaluative tool, much less a rationale to justify administrative extractions of higher rents from consumers.

Interestingly, VOS studies single out just one technology for "value based" compensation, solar DG. Tellingly, such studies never explore the implications of retail

[41] SolarCity witness Mr. Bean, for example, points out that location is very important if solar pv were to provide distribution system benefits. As he points out, that would require a level of planning and coordination between solar developers and utilities that do not currently exist. His basic point, however, is correct. For that reason, distribution benefits are theoretically possible, but, in the current circumstances of no coordination planning and random location of solar DG units, actual delivery is not only highly dubious, it is improbable. In marked contrast to that reality, Mr. Beach, as well as Conservation Law Foundation witness Mr. Paul Chernick, just make a leap of faith that, simply because system benefits are theoretically possible, regulators should deem them delivered and worthy of compensation, thus rendering consumers liable for "phantom" services that never actually materialize.

net metering or any other form of pricing on performance and innovation over time. In short, it is a claim of value out of the context of the market, costs or performance incentives. Most tellingly, every other product and service offered in the electricity marketplace is simply ignored, and it is presumed that they will be priced by either competition in the market, or based on costs. Appendix B, a recent article I published in The Electricity Journal, is a glimpse of what would happen if VOS theory were writ large across the power sector. It is designed to provide a broader perspective on many of the flaws in inherent in "value based" pricing that removes the discipline of either competition or cost based regulation.

Q. In his testimony, Mr. Thomas Beach asserts that there are "well accepted techniques" for analyzing the "value" of solar. Do you disagree with the implication that an accepted methodology exists?

A. I do disagree. The reality is well illustrated by the extraordinarily wide variance in the conclusions of VOS studies. The range is dramatic, with a VOS study in Louisiana finding a negative value (principally because it considered the cost of other government subsidies already supporting solar, which are usually excluded from such discussions even though they do constitute a social cost), with nearby Maine's VOS having the distinction of being an extreme outlier on the high value side, with a calculated "value" in Maine of 33.7 cents/kWh.[42,43,44] Additional disagreement exists over the individual

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[42] Dismukes, David E. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers. Prepared on behalf of the Louisiana Public Service Commission.* Prepared on Behalf of Louisiana Public Service Commission Draft, February 27, 2015. *Please see:* http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5.

[43] Grace, Robert C., Philip M. Gruenhagen, Benjamin Norris, Richard Perez, Karl R. Rabago, and Po-Yu Yuen. *Maine Distributed Solar Valuation Study*. Prepared for the Maine Public Utilities Commission. Revised April 14, 2015. *Please see:* **http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf**.

[44] To put the 33.7 cents /kWh valuation in perspective, that number is more than double the full retail rate of Maine's largest electric utility. In other words, the authors of

components that make up VOS analysis, as well as the correct context within which assessment should be made. For example, even the pro-net energy metering witnesses in this case do not agree on the proper "value of solar" approach. While Mr. Beach suggests that the Commission must review the value from three possible perspectives (the solar rooftop owner, ratepayers in general, and the utility as a whole),[45] Mr. Phelps argues that it is the perspective of society as a whole that should be given priority.[46] Simply stated, there is no consensus on how such studies should be deployed (e.g., to actually set prices, to justify retail net metering, etc.?), how they should be conducted, how deliverability of value should be judged, how one should define capacity for ratemaking purposes, whether energy prices should be assessed in real time or some other fashion, how employment benefits and costs should be evaluated, how much to rely on forecasts and levelizing costs and benefits, etc. There is almost no component of VOS analysis for which there is any commonly accepted methodology or framework. In short, VOS is subjective analysis subject to the whims and biases of whoever chooses to author such a study, and cannot be relied upon for any serious examination of pricing and ratemaking.

Q. Why do you say that most "values" asserted for solar in VOS studies are either imaginary or uncertain?

A. Even a cursory analysis of the various individual elements generally offered up to calculate the value of solar suggests that, with the exception of avoided short-term energy costs, and perhaps, on a time and location specific basis (as suggested by witness Mr. Bean, but ignored by witnesses Mr. Beach and Mr. Chernick), some savings on transmission congestion (although it is entirely possible there could be congestion costs, rather than savings, depending on circumstances), there is little bankable value there. Few

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that study calculated that the "value" of the energy produced by each rooftop solar installation is worth double the full delivered cost of electricity. That is the equivalent of saying that the value of a part of a product is worth double the value of the entire product.

[45] Beach testimony, 8-9.

[46] Phelps testimony, 9.

of the "values" attributed to rooftop solar in New Hampshire's or other VOS studies stand up to scrutiny, and those that do are compensated under appropriate ratemaking, to the extent they are real.[47]

Q. How do you evaluate claims about "levelized" avoided energy costs?

A. Rooftop solar generation, when produced, does reduce the amount of energy the utility must provide at the time the solar units are producing. Almost every participant in the conversation about solar DG agrees on this.[48] Caution should be exercised, however, when the suggestion is made that the value of the generation to be offset should be calculated on a "levelized" basis—projected for twenty years or so, and then averaged. This "levelized" analysis introduces unnecessary, highly uncertain, and unhelpful speculation about future gas prices and inflation, while doing little to illuminate how actual current cost savings should be considered. A "levelized" value number looks bigger, but caution must be used in understanding what this number means—comparing a

[47] An example of appropriate ratemaking compensating rooftop solar for benefits would be to apply the relevant locational marginal price (LMP) to the price paid for rooftop solar exported to the grid. That automatically captures not only the precise avoided energy cost at the same time that the energy is produced, but also captures the transmission congestion benefit (or cost, depending on the circumstances at a given location at a given time).

[48] Many value of solar analyses present the avoided energy cost as a "levelized" number, which factors in predictions of increasing energy costs in upcoming years to come up with a "levelized" avoided energy cost which is higher than the actual energy cost today. It is tempting here to focus on the fallibility of making reliable predictions about future energy costs (look at recent trends in natural gas prices. Most people did not foresee recent declines). But the whole issue of prediction is a red herring in this context, because RNM does not provide utilities with ownership of distributed solar resources, and therefore gives it no protection against future energy price increases. If an RNM system of compensation continues, reimbursement rates will always be tied to overall energy price increases. So costs of RNM to the utility will go up right along with savings. Trying to give solar resources credit ahead of time for rising energy costs needlessly complicates the analysis, which would then have to be balanced with appropriately rising net energy metering costs. It is simpler and less misleading to use current avoided energy costs, recognizing that these need to be updated regularly.

larger "levelized" value of solar against current (non-levelized) costs of RNM, for example, is comparing apples and oranges.

Q. What is your assessment of the claimed value associated with avoided capacity costs (generation and transmission)?[49]

A. The idea that having a lot of distributed solar on the system means that the utility requires less capacity of various kinds is one of the commonly asserted claims made by retail net metering advocates.[50] These claims are unfounded. Solar energy is intermittent and only available when the sun is shining, and, in the case of rooftop solar, only available for export to the grid if the sun is shining and if the solar customer is not using the energy produced on his/her rooftop. It is not and cannot be relied upon to produce any energy when called upon to do so, nor to reduce demand reliably, because there is no way to be certain that the conditions necessary for rooftop solar energy to deliver energy when called upon to do so will be met. In fact, since solar DG is not visible to the system operator, it is not dispatchable. Its energy output, whenever it exceeds on-premises demand, simply flows into the system. Thus, unlike every other form of generation, it is not dispatchable.

Of course, in their planning, utilities do consider the potential impacts of rooftop solar generation on overall capacity needs, from a probabilistic point of view. However,

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[49] Capacity in electricity refers to the resource's ability to produce energy (a generating resource) or to deliver energy (a transmission or distribution resource) when called upon to do so. What is produced (or delivered), of course, is energy.

[50] The testimony of Patrick Bean in this case is a good example. Mr. Bean suggests that the utility "leverage customer investments" to reduce needed investments in capacity, saving money overall (p. 8). This argument invokes the commonly heard idea that customer money invested in rooftop solar is "free." Under RNM, this is far from the case—RNM payments amount to a much higher cost that a utility would have to pay for any traditional capital investment loan. In fact, Mr. Bean may recognize this, because he goes on (p.8) to suggest a competitive bidding process that has nothing to do with RNM—in fact, RNM itself prevents development of such a process. Why should third parties bid to receive a competitive price, when a generous non-competitive subsidy is available?

as a former regulator, I believe there is an important distinction to be made in thinking about capacity from a ratemaking standpoint, as opposed to a planning standpoint. From a ratemaking standpoint, payments for capacity should depend on performance.

In the wholesale market, when a generator obtains a capacity payment, the generator agrees to either deliver the energy when called upon to do so, or assumes liability for supplying replacement energy. In contrast, rooftop solar providers under RNM make no such assurances. If the utility incorporates this "value" into rates, it potentially pays twice—first, in a lower rate for rooftop solar customers, and, second, if the rooftop solar producer fails to deliver, the utility must pay again, this time to an alternative supplier to provide what the solar provider did not. Indeed, given solar's intermittency, it would have to pay not only for the replacement energy that the solar provider failed to deliver, but also, perhaps, have to pay for the capacity required to back up the solar units. It is, quite simply, a "heads I win, tails you lose" proposition. From a consumer perspective, the capacity value claimed by VOS proponents is for phantom capacity, not something real. Consumers should not be obligated for capacity that cannot be relied upon either physically or financially.

In regard to transmission capacity, solar DG has virtually no impact whatsoever for a couple of the reasons. The first, as discussed above, is that intermittency requires backup not only in generation but also in terms of the transmission capacity to deliver. The second reason is due to scale. Displacing transmission capacity with distributed energy is not the "just in time" arrangement suggested by Mr. Beach. Rather, it is the result of extensive long term planning on an interactive basis with multiple parties looking out over a long term time horizon. It also involves capturing economies of scale, as well as optimal utilization of scarce right of way. Thus, the small scale of rooftop solar units, coupled with the uncertainty of how much will materialize and over what time frame, and in the context of intermittency, makes it extraordinarily unlikely that solar DG will have any appreciable impact on displacing the new for transmission capacity.

Q. What is your view on claims of potential savings related to power flow—savings due to reduced line loss reductions and ancillary services requirements?

A. It is true that energy losses occur during transmission and distribution. However, whether or not rooftop solar systems reduce the amount of energy lost in long distance transmission and distribution is a fact-specific question, dependent on an array of variables (including the location and times of generating energy of rooftop solar systems), and the answers may be counterintuitive. Electricity flows on wires according to laws of physics, following the course of least impedance, a natural phenomenon impacting every interconnected wire, regardless of whether the wire is sized to withstand the current.[51] As a result, energy flow on the grid is highly dynamic in real time. Every injection or withdrawal of energy impacts the ability to access the grid throughout the system. Maintaining optimal grid functionality requires careful planning, vigilant and prudent dispatchers, and the ability to call upon resources to provide what are called ancillary services, such as voltage support, reactive power, black start, and other very location and time specific service that are essential to grid operations, many of which also affect line losses.

Thus, with respect to the distribution grid, the production or non-production of energy affects line losses on a very location- and time-specific basis. While it is true that DG can have a salutary effect on line losses, it is equally correct to say that it could have an adverse effect on line losses. As a matter of physics, there is simply no generic "value"

[51] The flows of the high voltage transmission system and the low voltage distribution system are separate and distinct from one another, so the flows according to least impedance are system specific. While demand shifts at any given interconnection point where high voltage is stepped down to low voltage can influence flows on the high voltage system, the actual flows between the two systems are separated by transformers, so the flows between systems are controlled.

associated with rooftop solar reducing line losses on the distribution grid. Indeed, as noted above, given the random, unplanned siting of solar DG units, the likelihood that solar panels will be optimally located and in appropriate configurations to add system value is almost non-existent. Solar City Witness Bean, as noted above, essentially concedes that point. VOS claims of such value are little more than claiming that solar producers are entitled to compensation for system benefits that, perhaps, in theory they could provide, even though they simply cannot be relied upon to deliver, and, given that the siting of solar pv units is unplanned, that they more often than not do not deliver.[52]

With respect to the transmission grid, the issue is a bit different, because rooftop solar is not directly interconnected to the high voltage system. Nonetheless, rooftop solar, simply as a matter of scale, probably has very little impact on transmission line losses. Further, (here the counterintuitive interconnected properties of electricity grids come into play) there is no simple and reliable relationship whereby less power delivered to a certain location guarantees less congestion on the grid, and correspondingly fewer transmission losses. Injections and withdrawals of electricity to and from an interconnected grid impacts the whole grid. Inputs into the grid need to be carefully balanced with withdrawals to avoid overloading any specific wire and to allow for access to the cheapest possible generation. The impact of lessening demand from a particular node on the grid depends on the specific constraints affecting dispatch at a given point in time. Just as in the case of distribution, to the extent that rooftop solar impacts transmission line losses at all, it is very location and time specific, so generic conclusions are simply not reliable.[53] If utilities got to select exactly where distributed generation was installed, it might be possible to leverage DG to provide more reliable transmission

[52] See Footnote 14 above for more discussion of these issues.
[53] For a technical discussion, see M. Rivier, "Electricity Transmission," in Perez-Arriaga, ed. *Regulation of the Power Sector* (p. 276, footnote 8), which acknowledges that in some cases, increased demand at a node (a distribution node) can decrease system costs overall.

and distribution benefits. But this not currently how distributed generation installations work.

For this reason, there is no basis to claim that solar PV systems, *ipso facto*, reduce losses. Furthermore, additional costs can also be the result of efforts to incorporate new DG. On distribution systems, this point is being debated among experts, and it appears to be that DG could well, in some circumstances, increase losses or cause additional costs to be incurred to cope with the newly bi-directional energy flow on the distribution grid, which was designed and built to accommodate one directional flows. With regard to transmission losses, it is certainly true that distributed solar PV does not rely on high voltage transmission. That, however, is no assurance of value. Rooftop solar can also adversely impact the transmission system because of its intermittent and unpredictable nature, which requires utilities to incur expenses to assure that backup power is available in order to be able to instantaneously call upon other resources. Similarly, even when solar units are producing energy, those flows have the potential to cause changes in the flows on the high voltage transmission in ways that add congestion to the system. Should either such circumstance occur, it is likely that losses would be increased, not decreased.

Ancillary services, similarly, can be impacted in both positive and negative ways by distributed solar generation. Certainly, there is the potential for distributed solar installations to include "smart inverters," which have the potential to provide frequency regulation and reactive power even when the sun is not shining—but these are potential capabilities, which RNM does nothing to incentivize, and which should be thought of as a separate product from rooftop solar. To realize the potential benefit here, some form of separate compensation would be needed—and, in my opinion, such compensation should, like compensation for other forms of ancillary services, be provided as a result of services actually provided, not in the hope of services that could potentially be provided at some future date.

Q. What about the value attributed to environmental benefits, especially reduced costs for emission mitigation?

A. Even the emissions mitigation benefits claimed for rooftop solar are not unquestionable. Rooftop solar may have no emissions when producing energy[54]—but this is only a benefit if it is displacing fossil fuel generation of electricity, not competing non-carbon resources such as utility-scale solar or wind. It is simply impossible to show that rooftop solar always displaces carbon emitting units, or that it does so in reasonably efficient, cost effective, way.[55] The issue is made even more complex by the fact that even when carbon emitting plants are being displaced, those displaced plants are forced to ramp up and down in response to the intermittent flow of the solar produced energy because of the "duck curve" referenced above. Such ramping, in most fossil plants, runs contrary to the design parameters of the plant, therefore causing it to operate on a considerably less efficient basis, a circumstance which is very likely lead to more emissions, not less. It is also true that in New England, off-peak energy such as rooftop solar will not displace high emitting plants, such as coal[56] or oil,[57] whose operating characteristics and dispatch

[54] If one considers the entire cycle of manufacturing solar panels, most of which are made in the world's most carbon intense economy, China, plus the necessity of shipping the panels halfway around the world, it can hardly be argued that solar PV is carbon neutral.

[55] Indeed, based on the Lazard study noted earlier, we know for a fact that using rooftop solar to reduce carbon emissions is more expensive and less efficient than using other renewable energy sources for doing so. Similarly, purchasing renewable energy credits in states and/or regions whose power sector is more coal intensive than New England would also be a more cost effective means of reducing carbon emissions. In essence, advocates of prioritizing rooftop solar to reduce carbon emissions are calling for consumers to pay far more to reduce carbon than they would otherwise have to spend. That is not only unfair to consumers, but is also likely to significantly dampen the public appetite for reducing greenhouse gas emissions. For those of us concerned about climate change, that could have highly adverse consequences.

[56] It is worth noting in this context that New England has very few coal burning plants and those that remain are slated for retirement fairly soon. Moreover, those that are operating are baseload units which are not designed to ramp up or down depending on the state of solar production.

history demonstrate that they are extremely unlikely to be displaced by rooftop solar. That is because, as noted above, solar DG is almost always off peak, so that oil units are not running, and because the few coal plants remaining in New England tend be baseload and are unlikely to be displaced. What is likely to be displaced are natural gas units, which are low level emitters. Hence using solar to offset low emitting natural gas fired plants is an economically inefficient way to reduce carbon. In fact, given that there is a regional cap on carbon under the Regional Greenhouse Gas Initiative (RGGI), in which New Hampshire participates, any carbon reduction through net metering, a mechanism outside of the RGGI cap, serves to drive down the price of carbon in the marketplace, thereby making carbon reduction less efficient, more expensive, and suppressing the development of more efficient technologies to reduce carbon emissions. Simply stated, it is counterfactual to assume, as a linear proposition, that more rooftop solar means fewer emissions.

Q. Is there real value associated with avoided purchased power risk, or "hedging?"

A. Not for the utility or its non-solar customers. Many "value of solar" advocates suggest that distributed solar power should get credit for being a hedge against increasing natural gas costs. This claim does not make sense in the context of RNM and the value distributed solar offers to the system as a whole. Solar power potentially has value as a hedge against natural gas, but only for the <u>owner</u> of the solar panels, or for an entity with a guarantee that it can obtain reliable energy supply from the panels at a fixed, unchanging price. For a utility that will be buying power from solar panel owners, and the customers those costs will be passed on to, without a long term fixed price contract (as is the case under RNM, which varies with the retail rate) the hedge value under net metering is nonexistent. More important, however, is the fact that the RNM price to be

[57] To the extent that oil fired plants are still utilized in New England, they are generally peaking units. Given that solar production in the region is almost entirely off peak, oil plants are not displaced by solar DG.

paid by the utility for power from rooftop solar will include all of the elements included in the monthly electric utility bill, including the full cost of energy. When gas is expensive, the price paid by non-solar customers will be higher; when it is cheaper, it will be lower. Given that the retail rate paid for rooftop solar includes the cost of energy, it is literally impossible for solar DG to serve as a fuel hedge for non-solar customers. So, if it is worth hedging against variations in the price of natural gas, the utility should buy the same hedge against variations in the price of rooftop solar power sold under RNM. From the utility's and the non-solar customer's point of view, the two costs will vary together. Thus, the hedge value is not only zero; any consideration paid for such a hedge would be more expensive than incurring the risk from which protection is sought—this is like paying for vacation insurance that costs more than the trip itself.

Q. What about the value of "market price mitigation"?

A. Another supposed value attributed to rooftop solar in many VOS studies is that by reducing demand, rooftop solar will suppress the market price for energy. This argument is seriously flawed in more than one way.

In the first place, under RNM, the price of rooftop solar is not market-based, or even cost-based. In fact, where there is RNM, the rooftop solar price is unreasonably and arbitrarily linked to the full retail price of delivered electricity, as opposed to the level of energy prices, where it should be. While, arguably, the availability of highly-subsidized rooftop solar could have the effect of reducing demand for wholesale energy (although considering the scales involved it seems improbable that the reduction would materially impact wholesale energy prices), there would be no price benefit for consumers since rooftop solar, priced at full retail levels, or at the levels dictated by the inflated claims of many VOS papers, would consume all of the savings and leave little or no benefit for customers.

Setting aside the high price customers are being asked to pay for this "savings," the second problem to flag here has to do with the different market effects of a low-priced competitive resource and a low-priced subsidized resource. If a competitively priced, not heavily subsidized, source of energy caused prices to decline, that would be a good thing, but that is not at all what VOS studies are suggesting will happen with rooftop solar. Rooftop solar is subsidized by tax credits, REC/SREC markets, and by the cross-subsidy inherent in net metering and volumetric rate design. It is hard to find any economic logic to support the notion that markets are well served by using heavily subsidized products, such as rooftop solar, to drive down prices in the competitive marketplace.

To the extent that highly subsidized products compete with unsubsidized products in the marketplace, this distorts the market, rather than strengthens it, making it hard for otherwise competitive energy generators to stay in business. In the long run, this distortion exacerbates the capacity issues that many markets struggle to correct through capacity payments. Thus, if one assumes that rooftop solar somehow suppresses prices in the energy market, this would be highly unfortunate—it could do very serious damage to the power sector. The claimed price suppression "value" is not a value at all.

Q. Is there real value associated with avoided distribution grid costs, resulting from rooftop solar?

A. While it is theoretically possible that there could be benefits for the low voltage grid as a result of distributed solar generation, it is also possible that there will be more costs than benefits. Distributed generation imposes costs and burdens on the grid by adding transaction costs and, in many cases, by compelling substantial changes in local networks to reflect the fact that the flow of energy is being changed from one directional to bidirectional. Significant geographic concentration of solar PV may cause the utility to have to make very substantial capital investment to upgrade the grid to accommodate the new flows put on the system. In California and New York, in fact, serious consideration is being given to totally restructuring distribution grids in order to effectively manage the new flows, both physical and financial.[58] While such accommodations can be made, policy makers do need to understand that there are costs associated with making them and should be mindful of who must bear responsibility for those costs.

Part of the problem is that, unlike all of other energy resources whose siting is part of a carefully planned integrated process, in which the connecting infrastructure is often dealt with concurrently, or is capable of anticipation, distributed generation is completely unplanned. In fact, since the installation of rooftop solar is the result of an individual's decision, there is no possibility to plan. The result is that the operator of the low voltage grid has to constantly play "catch up," a process which can be time consuming and costly.[59] Moreover, even in cases where a rooftop facility does reduce distribution costs, that is a specific function of location and time, something which may not be true of a neighbor's facility, much less one located across town. Thus, any generic claim that the installation of rooftop solar adds value to the grid simply cannot be regarded as credible.

Q. Should value be attributed to rooftop solar based on its impact on economic development and jobs?

A. No. Advocates of subsidies for distributed solar generation often point to supposed economic benefits—particularly job creation in the solar installation field.[60] But claims

[58] Southern California Edison recently put forward a rate case which included $2.3 billion for changes to the grid to accommodate distributed energy resources. See September 21, 2016 Utility Dive article: http://www.utilitydive.com/news/how-southern-california-edisons-new-rate-case-would-transform-the-grid/426493/

[59] Mr. Patrick Bean, as noted elsewhere, in fact recognizes, in his testimony, that problems are created by lack of control over siting, suggesting a system of incentives for siting generation in higher-value locations. (Bean, p. 11).

[60] There may be some question as to the quality of at least some of the jobs the solar witnesses claim will be gained. In its most recent 10K filing with the SEC, Solar City, the largest vendor/lessor of solar DG, acknowledges a pending investigation by the U.S. Department of Labor (*Solar City 10K Annual Report*, Feb. 2016, p. 33, available online at: https://www.last10k.com/sec-filings/scty#Item_1A).

about a positive impact on job creation are one-sided—they count new jobs created in solar—but if the cost of electricity is higher, jobs are likely to be lost elsewhere in the economy—there is no reason to assume that the net job impact of distributed solar power is positive. In fact, a recent study by Tim James, Anthony Evans, and Lora Mwaniki-Lyman of Arizona State University used an Arizona-specific regional economic model (a REMI model), balancing the costs of installed rooftop capacity (and related financing costs) against what APS estimates to be the related savings on generation purchases and generation capacity investment over thirty years (and their related customer savings), based on different levels of investment in solar DG that might be made in the APS service territory. This study models the complexity of judging the economic and job impacts of a particular policy or subsidy—of course, there is an immediate positive impact on some jobs from additional solar employment, but, over time, taking into account the effects of lost spending power by consumers who have to pay more for their electricity, the projected impacts on jobs and on the gross state product of the Arizona economy are decidedly negative (for example, the model shows cumulative losses in gross state product, over time, in the multiple billions of dollars).[61]

The argument that solar DG creates jobs is not only wrong on the facts; it sets a disturbing precedent. In essence, the argument that inequitable solar DG cross-subsidies must be continued because of the potential impact of any change on solar jobs is the same one dimensional, simplistic, and, frankly, irrelevant argument as that made by the coal industry against carbon controls—that coal mining and related jobs may be lost. This is not a good argument applied to coal, and it is not a good argument applied to solar DG.

[61] James, Tim, Anthony Evans, and Lora Mwaniki-Lyman. "The Economic Impact of Rooftop Solar in the APS Service Territory, 2016-2035." Report, L. William Seidman Research Institute, W.P. Carey School of Business, Arizona State University, February 16, 2016. (available online at: http://seidmaninstitute.com/wp-content/uploads/2016/03/ASU-Seidman-study-2016_FINAL.pdf)

Before leaving the topic of jobs, it is worth remembering that most solar panels sold or leased in the U.S. are manufactured in China. In all likelihood, more American jobs are associated with other forms of generation.

IV. PROBLEMS WITH MR. BEACH'S NEW HAMPSHIRE "VALUE OF SOLAR" ANALYSIS

Q. Do these general objections apply to the analysis of the value of solar in New Hampshire presented by Mr. Beach in his testimony? [62]

A. Yes. Mr. Beach's analysis is unusual only in that it is particularly difficult to follow, due mostly to Mr. Beach's insistence that the Commission must consider value from multiple perspectives, though also to a system of results reporting that switches between $/kWh and $/mWh, and that doesn't always make clear the results of which of the four tests Mr. Beach uses are being reported. My analysis, below, focuses on Mr. Beach's "ratepayer impact measure" test, which is the only test relevant to the question of the existence of cross-subsidies. I examine some of the key value categories and explain what is wrong with the methodology and findings of the study in these areas.

Overall, Mr. Beach's "ratepayer impact measure" barely breaks even for residential ratepayers (it does a little better for the commercial sector). As I argue in what follows, when you consider all the costs that Mr. Beach omits and all of the benefits he unjustifiably includes, it is clear that this apparent narrow ratepayer benefit is non-existent and that, in fact, a significant cross subsidy is occurring under New Hampshire's current net energy metering rates.[63]

[62] Although Mr. Chernick also addresses the issues discussed by Mr. Beach, I am largely ignoring his comments on the subject, in part because that would be repetitive, but also because, unlike Mr. Beach, Mr. Chernick makes no effort to substantiate his claims.

[63] Mr. Beach himself does not seem to be convinced by his own analysis that there is no cross subsidy. Though his analysis asserts that ratepayers are benefiting, or at least breaking even, under current net energy metering rates, elsewhere in his testimony he

Q. Do you agree with the criteria Mr. Beach suggests should be used for evaluating changes to rate design applicable to net-metered customers?

A. No. Mr. Beach states that any new design "should be tested to ensure that, after it is applied, DG will remain a viable economic proposition for participating ratepayers."[64] I strongly disagree. The Commission has no obligation to ensure that rooftop solar customers must be able to make money from their investment, particularly if (as is the case), keeping rooftop solar customers "in the money" requires significant subsidies from customers without rooftop solar. It is interesting to note that this proposed criterion puts zero pressure on rooftop solar companies to reduce costs and perhaps to accept lower profit margins, or even pass on the declining costs of solar panels in order to keep rooftop solar investments appealing. Profitable rooftop solar investment may well be possible under a fair approach to energy billing—but this may require a re-negotiation of terms between rooftop solar customers and rooftop installation companies. It is in no way the responsibility of the Commission to guarantee that these systems will be profitable. It is the responsibility of the industry, under fair pricing and open competition, to demonstrate to potential rooftop solar customers that it can provide real value. For this reason, I suggest that the time and attention Mr. Beach spends in his analysis of the value of solar to rooftop solar customers under current net energy metering programs is irrelevant to the question of whether such rates should be changed. Finally, Mr. Beach's basic premise is that the design of rooftop solar rates should be focused on maximizing the number of units sold. In my view, that may be the commercial objective of his clients, but it is decidedly not the type of balanced and nuanced public policy one would expect from regulators and policymakers.

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argues for the benefits of a minimum bill based on the likelihood that it will reduce the size of DG rooftop installations, "thus reducing the cost of net metering for other ratepayers." (Beach testimony, p. 37). Beach's argument here is not consistent with his claim that rooftop solar is a net benefit on all his measures.

[64] Beach testimony, 29.

Q. Are there any major ratepayer impacts omitted by Mr. Beach in his analysis?

A. Yes, absolutely. First, in his testimony, Mr. Beach notes that the cost-benefit analysis of solar DG he performs "focuses on generation exports."[65] This means that, from the point of view of analyzing cross-subsidies among ratepayers, he omits any consideration of the costs a rooftop solar customer avoids paying when he or she produces electricity for his or her own consumption. Mr. Beach sets up this approach by arguing that a rooftop solar customer producing for his or her own consumption is equivalent to a customer taking energy efficiency measures to reduce consumption. However, as explained above, it is important to understand here that rooftop solar customers producing for their own consumption are importantly different from energy efficiency customers—their overall energy consumption (kWh) goes down significantly, but their peak demand (KW) does not. For example, a customer who improves energy efficiency by installing LED bulbs throughout his or her house presumably reduces both the total kWh of energy used and the peak demand in the house. In this case, the standard residential two part rate, which varies only with kWh usage, is a reasonable way to approximate the costs customers impose on the system. A rooftop solar customer can reduce kWh consumption significantly, while reducing peak demand very little, or even not at all, if peak demand occurs after sundown (not uncommon, in working families whose members return to the house in the evening). Such customers pay much less to support the same peak demand—and other customers must make up the difference. There is a real "ratepayer impact," here, but it is one that Mr. Beach omits entirely from his ratepayer impact analysis. Even so, his analysis of ratepayer impact for residential customers barely breaks even for all three utilities he analyzes.[66] It is also important to note that energy efficiency results tend

[65] Beach testimony, 26.
[66] Beach testimony, Table 4, p. 27.

to be more predictable than is possible in terms of what can be expected from an intermittent resource.

Q. Do you agree that 25 year "levelized cost" analysis is an appropriate way to review the costs and benefits of rooftop solar?

A. I do not agree. In his analysis, Mr. Beach suggests that "levelized" cost analysis should be used for rooftop solar, in the same way that utilities use such analysis to evaluate potential capital investments in new plants.[67] However, as discussed above, in relation to the approach to valuing energy provided by rooftop solar, since utilities do not themselves own the rooftop solar facilities, conducting an analysis identical to that undertaken for a capital investment does not make sense and introduces needless complexity. There is no 25 year ownership right (for the utility) to the rooftop solar power to be provided, so traditional analysis of whether an asset is worth investing in does not apply. Mr. Beach further suggests that levelized analysis is needed because there are benefits from rooftop solar that can only be realized over time (primarily, capacity benefits). His analysis insists that such benefits be included; however, he does not endorse equal foresight about potentially growing costs. For example, increases in distribution costs or costs of coping with variability that Mr. Beach acknowledges may come along with growing levels of solar penetration are not considered in his "levelized" analysis; rather, Mr. Beach says, "further analysis may be needed" in the future, once penetration levels increase.[6869] A "levelized" analysis that considers all hypothetical

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[67] Beach testimony, 10.

[68] While Mr. Beach acknowledges that further analysis may be required, by levelizing prices into a long term arrangement, he precludes the possibility of revising rates to reflect more sophisticated and updated analysis.

[69] Beach testimony, p. 15. Similar discussion of variability on p. 17.

changes in benefits over 25 years but omits hypothetical changes in costs is misleading, and only adds to the difficulty of appropriately assessing the "value" analysis presented.[70]

Q. Q: In addition to the general concerns with "Value of Solar" analysis described above, are there any particular issues with this analysis for New Hampshire that should be mentioned?

A. A. Yes. With respect to the category of "societal benefits," a few items should be noted:

- Mr. Beach includes a value for the avoided social cost of carbon.[71] However, given New Hampshire's participation in RGGI, there should be no additional value at all attributed to the social cost of carbon, beyond the RGGI values incorporated in the energy cost analysis. The reason for this is that RGGI is a cap and trade system. Under this system, additional measures to lower carbon emissions do not result in lower emissions overall (they do nothing to change the "cap")—what they do instead is to undermine the value of carbon credits under the RGGI system, make the whole system less efficient, and direct a greater share of the cost of compliance with RGGI onto New Hampshire ratepayers, as opposed to ratepayers in other states, without lowering total carbon emissions for the RGGI states overall. Although, as a Massachusetts resident, and a homeowner in Maine as well, I benefit from New Hampshire taking on additional costs in order

[70] An example of the kind of difficulty introduced by levelized analysis can be seen in the use of EPA AVERT data for estimating the value of various avoided pollutants. The EPA itself warns that the AVERT data "should not be used to examine the emission impacts of … changes extending further than five years from the baseline year." (see **https://www.epa.gov/statelocalclimate/avoided-emissions-and-generation-tool-avert#when)**. It is not clear how Mr. Beach handles this, exactly, but calculations of the 25 year "levelized" value of avoided emissions are certainly included in his final figures.

[71] Mr. Beach also includes the market value of carbon under the Regional Greenhouse Gas Initiative (RGGI) in the category of avoided energy costs. These energy-related values are subtracted from the calculated social cost of carbon (presumably, to avoid double counting). Beach testimony, p. D-10.

to lower the cost of RGGI compliance for Massachusetts, I cannot advise this policy as one that is a good investment for New Hampshire ratepayers or that has any benefit for the climate or for society as a whole. Moreover, it violates a basic principle in regulation, namely, that the cost causer should pay (or, in a variation of that principle, the polluter must pay). Thus, all "societal benefits" associated with carbon emissions should be eliminated from the analysis.

- Avoided SO2 and NOx costs. The New Hampshire study shares with the Maine study the methodological problem of using the EPA's Northeast AVERT data as a source for calculating the avoided emissions from rooftop solar generation.[72] The Maine study, however, notes that the AVERT data used to calculate emissions "includes New York, which is not part of the ISO-NE control area."[73] The Maine study's appendix goes on to clarify that if the authors had in fact limited the analysis to "FTA rates"—emissions rates for units fueled with oil and natural gas (closer to what the Maine study authors assume is being displaced in their marginal cost analysis) emissions rates would have been radically lower. [74] What this boils down to, is an admission that the "value" attributed to SO2 and NOx emission reduction is a complete fiction, based on a calculation that rooftop solar in Maine (or in New Hampshire, in the current example) would somehow reduce coal plant emissions in New York. This is ridiculous. Coal is at all times unlikely to be used as a marginal resource—and these coal plants are not even part of the same dispatch system as New Hampshire. It is hard to know what the true values

[72] Grace, Robert C., Philip M. Gruenhagen, Benjamin Norris, Richard Perez, Karl R. Rabago, and Po-Yu Yuen. *Maine Distributed Solar Valuation Study.* Prepared for the Maine Public Utilities Commission. Revised April 14, 2015. *Please see:* **http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf**

[73] *Id*. at 83

[74] *Id*. at 84.

for SO2 and NOx should be, but it is unlikely that they are as high as those included in the New Hampshire study.[75]

- Another critique of Mr. Beach relates to his assertion that the investment in rooftop solar relieves the utility of having to raise more capital. That is incorrect for three very basic reasons. The first is that, as already noted, solar's intermittency means that a utility will have to incur obligations for transmission and generation backup capacity. Second, the accounting results may well compel the utility to treat that obligation on its books as debt, thereby having implications for the company's debt-equity ratio. Finally, there will be lead/lag implications, because new solar customers will be paying less of their fixed costs, and companies will be unable to recover those foregone revenues until their next rate case where they can shift those cost to other customers, thereby exacerbating the cross-subsidy inherent in RNM.
- There is a general concern about relying on long term fuel price forecasts. While utilities and regulators might have to do so for purposes of planning, it is an entirely different proposition to use such notoriously inaccurate forecasts for purposes of long term contracts. There is a lot of history relating to the consequences of what can go wrong when one relies on long term forecasts to lock in long term prices. As a regulator, I had to deal with these problems, and I do not wish to see them revisited on consumers of New Hampshire.

Q. Given your global critiques of the "value of solar" analysis presented by Mr. Beach and your critiques specific to New Hampshire, where does this leave us in terms of likely ratepayer impact of net energy metering in New Hampshire?

[75] I believe the same problem impacts estimates of avoided CO2 emissions—once again, the report relies here on annual avoided emissions calculated from AVERT—which includes coal plants, whose CO2 emissions are significantly higher than natural gas plants.

A. Focusing on the Rate Impact Measure analysis conducted by Mr. Beach (which excludes societal benefits), the apparent balance found by Mr. Beach disappears when appropriate adjustments are made:

- Eliminate (or greatly reduce) "generation capacity" and "generation capacity reserve" savings (based on the lack of coincidence with peak discussed above, a problem only expected to increase with increasing penetrations of rooftop solar);
- Eliminate savings related to transmission and distribution (as discussed above, these are highly time and location specific, and far from guaranteed);
- Eliminate savings attributed to "market price response" (in the long run, market price suppression distorts the market and leads to capacity problems that can be expensive in their own right);
- Eliminate savings attributed to "avoided fuel price uncertainty" (as discussed above, under net energy metering, prices paid for rooftop solar power by utilities vary right along with fuel prices—so rooftop solar, under NEM arrangements, does not provide utility customers with a meaningful hedge against price uncertainty);
- Include additional costs identified in the testimony of Thomas P. Meissner in this case, related to investments needed to preserve the stability of the distribution system given the new, two-way power flow enabled by rooftop solar.[76]

Without significant additional analysis, and relying on Mr. Beach's estimates of "levelized" cost and value of the energy itself, it is clear that the "value of solar" that remains is far less than the ratepayer cost of the current net energy metering subsidy. For example, the analysis of the impact of current net energy metering for Unitil (residential and commercial) goes from a small net positive to a large negative—if per kWh energy

[76] Meissner testimony, 10.

avoided costs ("levelized") are taken to be represented by Beach's estimate of \$0.06/kWh[77], they clearly fail to balance the lost revenues estimated by Beach to be \$0.19/kWh[78]—and this is without taking into account any of the additional distribution costs that Mr. Meissner's testimony notes will be necessary. As this rough analysis makes clear, a more accurate assessment of the "value of solar" shows that solar falls far short of providing a "value" equivalent to the net energy metering subsidy.

Q. Does your critique of Mr. Beach's testimony have implications for the testimony of Mr. Nathan Phelps and/or Mr. Patrick Bean?

A. Yes. Both testimonies rely on Mr. Beach's analysis to support their claims about the value of solar.

Q. Nathan Phelps also presents a "value of solar" analysis. Does his analysis offer any additional values that are significant?

A. No. Mr. Phelps argues that the Commissioners should focus on the "societal cost test," the most global, all-encompassing standard for evaluating the value of solar, including value provided to society and the environment.[79] His analysis, however, is subject to the same objections as the Beach analysis, and does not provide any new reason to attribute additional value to rooftop solar power.

V. HOW THE THREE-PART RATE PROPOSED BY UNITIL CAN HELP ADDRESS THE INEQUITIES AND INEFFICIENCIES OF RETAIL NET METERING

Q. What is the national context for New Hampshire's current review of net energy metering?

[77] See Beach's Table D-12. For the sake of clarity in comparing this number with the cost number Beach presents in Table D-17, I have converted the per MWh figure presented in Table D-12 into a per kWh figure.

[78] See Beach Table D-17, page D-16 of Beach testimony.

[79] Phelps testimony, 9.

A. Unsurprisingly, given the problems with RNM explained above, many policy makers, regulators, and utilities are examining how to better structure rates for distributed generation customers. There is a robust debate occurring across the nation regarding the appropriate rate mechanisms for addressing the issues raised by distributed generation technologies, with a growing recognition throughout the United States that traditional RNM is not sustainable as a pricing methodology. For example, in 2015, 46 out of 50 states had ongoing studies, proposals, or enactments relating to "net metering, valuation of distributed solar, fixed or solar charges, third-party or utility-led rooftop solar ownership, or community solar."[80] These states stretched from coast to coast, including Nevada, Ohio, Pennsylvania, Virginia, Connecticut, and Maine.[81]

In the first quarter of 2016, thirty-nine states took some action related to "net metering, rate design, and solar ownership," according to the NC Clean Energy Technology Center's report (p.9). The report describes a continuing "trend" of fixed charge increase requests by utilities, with 19 such requests pending at the end of March 2016 (50). Proposed changes are often controversial. Florida has seen dueling proposed ballot initiatives. Hawaii recently ended its RNM program. In Nevada, RNM reform has attracted considerable national attention. Other states (in addition to New Hampshire) which are at various stages of review and revision include Kansas, Arizona, Massachusetts, Vermont, California, Wisconsin, Mississippi, Ohio, Maine, Maryland, Louisiana, and recently Colorado. The old national *status quo* of net metering is being reexamined in a growing number of jurisdictions across the country. In some jurisdictions, utilities are moving to replace RNM with a three part rate including a demand charge, under which customers pay a monthly charge based on their peak

[80] North Carolina Clean Energy Technology Center & Meister Consultants Group, The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report, February 2016: 11.

[81] Ibid, p. 40.

demand for that month. Such a charge can be optimized by setting "peak hours" when it applies. This three part rate structure corresponds to Unitil's proposal to the Commission.

Q. Is Unitil's proposal for a three part rate a good approach to net energy metering reform?

A. Yes. The appeal of a three part rate is its promise of fully implementing the principle of setting rates in accordance with cost causation for each of the three kinds of costs (fixed, demand, and energy) customers impose on the system. What this means is that under a well-structured three part rate, cross subsidies from non-solar to solar customers would be eliminated. Under a three part rate, rooftop solar customers can be charged accurately based on the utility's cost of providing service, in conformity with the most basic and important principles of utility ratemaking.[82]

Such a three part rate can be complemented by other measures designed to further refine and sharpen price signals, including time and location-based incentives for siting rooftop solar advantageously, and time of use rates to incentivize customers to consume more when rates are lower and produce more when rates are higher. In this respect, I agree with the testimony of Mr. Bean, who recommends these measures.[83]

[82] Mr. Bean raises the concern that demand charges might increase overall energy use, since breaking such charges out separately would result in lower per kWh rates. What is important to note here, however, is that, because this moves the rate close to reflecting actual customer costs imposed on the system, the end result will be more efficient for both customers and utilities. Similarly, if demand charges, for example, motivate some customers to convert to natural gas-fired appliances, this is not a bad thing, if it is an overall more efficient result. And because the new rate would be an accurate reflection of customer costs imposed on the system, such a conversion would not, as Bean suggest, leave other customers "on the hook" for more system costs. The three part rate, properly structured, eliminates the concern that my actions to save money on my bill will negatively impact other customers. (See Bean testimony, 15). I would also note that having transparent, unbundled demand charges will enable readily available technology to help customers control the demand characteristics to enter the market and provide consumers with another option for controlling their bills.

[83] Bean testimony, 11.

CONCLUSION

Q. Do you have any concluding remarks?

A. Yes. The inequities and inefficiencies of existing retail net metering rates across the country are increasingly being recognized as both unjustifiable and unsustainable in a world in which rooftop solar power is no longer an infant industry, but rather a growing a robust part of the energy sector. The long-term success of distributed solar as an energy resource must depend on its becoming truly cost competitive with other resources, and rate reforms to more realistically compensate distributed solar are an important part of making this transition. Unitil's proposal to revise the current Net Energy Billing make it consistent with its name ("net *energy* billing," not "net energy, transmission, and distribution billing) would establish the conditions necessary for fair competition, and the potential for market forces to drive increasing efficiencies and set the stage for rooftop solar to compete on a level playing field with other forms of energy generation, eliminating the cross subsidies that currently distort prices and unfairly burden non-solar customers.