EXHIBIT
#17
DE 16-576

BEFORE THE STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

In the matter of:)
Electric Distribution Utilities)
Docket No. DE 16-576)
Development of New Alternative Net Metering Tariffs)
And/or Other Regulatory Mechanisms and Tariffs for)
Customer Generators)

Direct Prefiled Testimony

Of

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Dated: October 24, 2016

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OFFICE OF CONSUMER ADVOCATE

TESTIMONY

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

I. Introduction

Q. Please state your name, position, employer and address.

A. Lon Huber. I am a Director at Strategen Consulting LLC located at 2150 Allston Way # 210, Berkeley, CA 94704.

Q. Please state your educational background and work experience.

A. My career in the energy industry began in 2007 when I started working at a research institute housed within the University of Arizona. In 2010, I became the governmental affairs staffer for TFS Solar, a solar PV integration company based in Tucson. I was hired by Suntech America in 2011 where I led the company's regulatory and policy efforts in numerous US states until December 2012. In 2013 I served as a consultant for Arizona's Consumer advocate office, RUCO, on energy related issues. I then joined RUCO as a full-time employee. At RUCO I was the staff lead on high profile dockets around net metering, resource procurement, and utility solar programs. I decided to join Strategen Consulting in March 2015 where I currently work on distributed generation issues across the US. I obtained a Bachelor of Science Public Administration degree in Public Policy and Management from the University of Arizona in 2009. I also received a Master's of Business Administration from the Eller College of Management at the same university. A resume is attached in Exhibit 1.

Q. Have you previously participated in similar Net Energy Metering successor tariff proceedings?

A. Yes. Many over the years in various capacities. I have either submitted testimony or been highly involved in the following recent dockets:

- Arizona Docket No. E-000000J-14-0023 - In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation.
- Maine Docket No. 2014-00171 - Commission Inquiry into the Determination of the Value of Distributed Solar Energy in the State of Maine
- Maine Docket No. 2015-00218 - Commission Initiated Inquiry into Market-Based Solar Policy Design Stakeholder Process
- Massachusetts Docket No. 15-155 - Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company…
- Arizona Docket No. E-01933A-15-0322 - In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to Its

  Operations Throughout the State of Arizona and for Related Approvals.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present the OCA's proposal for new net metering tariffs as required by H.B. 1116 (Chapter 31 of the N.H. Laws of 2016, amending RSA 362-A:9) as it relates to the interests of residential customers.

II. Principles

Q. Did OCA adopt broad principles to guide its approach to this docket?

A. Yes, they are as follows:

1. Principle #1: Separate compensation for distributed generation (DG) from traditional retail rates.
2. Principle #2: Compensation should decrease as the price of technology decreases.
3. Principle #3: Create programs that can scale sustainably as the solar industry matures, and ultimately increase the savings delivered to all ratepayers
4. Principle #4: Offer a reasonable amount of certainty to participating customers, industry, and all ratepayers.
5. Principle #5: Provide opportunities for all customers to participate in DG.

III. Approach

Q. Please describe the general approach of this round of testimony.

A. In this first round of testimony the OCA intends to provide a high-level policy position that describes its current inclinations and outlines an illustrative program design. The OCA is not suggesting that the positions offered in this testimony are set in stone. The OCA actively seeks opportunities to work with stakeholders to make reasonable modifications in response to constructive feedback that aligns with the OCA's policy positions and overall mission.

Q. What is the OCA's mission?

A. The New Hampshire Office of the Consumer Advocate is responsible for representing the interests of residential customers of the state's regulated utilities, including electricity, as defined in RSA 363:28. The OCA fulfills this responsibility in significant part by participating in New Hampshire Public Utilities Commission proceedings such as this docket. By forcefully advocating on behalf of residential utility customers, the OCA helps the PUC achieve its statutory mission of serving as the arbiter of the interests of utility shareholders and utility customers as required by RSA 363:17-a.

Q. How should one interpret the program design presented in this testimony?

A. Parties should interpret the proposed program design to be a conceptual representation of the OCA's preferred approach. Programmatic and implementation details are kept at a high level and the OCA intends to offer more details in subsequent filings and as we hear from other parties and review their testimony. The OCA is open to suggestions on how to improve upon the proposed tariffs so that they are both effective and easy to implement. To reiterate, the OCA hopes to work collaboratively and constructively with other parties to this proceeding and is willing to be flexible in its approach. However, the OCA is also prepared to defend its positions fully and vigorously throughout a litigated hearing if such defense becomes necessary.

IV. Summary of Testimony

Q. Please briefly summarize your testimony.

A. I first discuss the legislative requirements and outline how the OCA's comprehensive proposal meets the objectives of the legislation. The policy increases in-state solar deployment but at a price 60-80 percent less costly than the current net metering construct. I present a framework that will minimize policy confrontations and promote market stability so businesses can plan and scale. Secondly, I discuss why New Hampshire is in need of modernizing rates and programs to accommodate new technologies, not just solar, and why now is the time to address this need. I recommend two main offerings: a Distributed Generation (DG) Time-of-Use (TOU) Rate, available to residential customers, and a Fixed Solar Credit Option open to all customers even renters or those without proper roof space. These offerings expand customer choice, mature the solar market to a point of greater self-sufficiency, and protect non-participating ratepayers from excessive cost shifts. I conclude by discussing the value of solar to the New Hampshire electricity grid and why the state should focus on win-win policies that share those benefits between solar adopters and all ratepayers while ensuring proper cost recovery to utilities.

V. <u>Brief summary of Legislation and Relevant Positions</u>

Q. Please summarize the legislative requirements for an alternative net metering tariff.

A. Through the passage of H.B. 1116, New Hampshire law newly requires the Commission to consider several aspects of an alternative tariff, including: cost and benefits of customer-generators, the need to avoid unjust and unreasonable cost shifting, rate effects to all customers, alternative rate structures, total capacity and size caps, automatic rate adjustors, and the administrative processes to implement the new tariff. The commission may also approve time and/or size limited pilots. H.B. 1116 explicitly contemplates that customers may interconnect distributed generation (DG) systems above the cap if necessary during this proceeding but requires these customers transition to alternative tariffs following their approval.[1]

[1] RSA 362-A:9, XVIII.

Q. Please summarize the OCA's considerations and positions regarding each of the legislative requirements.

A. The OCA has considered and developed a position for each of the following requirements when developing its tariff recommendations. These initial positions will be further expanded upon in the following sections as well as in additional testimony filings. However, the OCA is pleased to provide a summary of how we meet each requirement:

a. <u>Cost and benefits of customer-generator facilities</u>

The OCA calculated costs and benefits of readily available or easy to quantify value categories. The results, presented later in this testimony, show that solar energy can provide a net benefit to all ratepayers if the right program structures are in place. While there may be some transition time to realize a net neutral value proposition for ratepayers across all the various solar market segments, larger scale systems will hit this threshold first and then start to provide net benefits to all New Hampshire ratepayers. Under the OCA's proposed framework, this win-win outcome can be realized within five years. OCA's preliminary analysis indicates potential benefits to New Hampshire utility customers due to DG solar ranging from approximately 13-15 cents/kWh. This does not include several categories of potential societal benefits that are difficult to quantify such as avoided air emissions, avoided fuel price uncertainty, benefits to the local economy, etc. Under traditional net metering, the compensation rate or equivalent bill offset rate can be thought of as costs to non-participating utility customers. Both of our proposed net metering alternative tariffs (the DG Time-of-Use (TOU) Rate and the Fixed Solar Credit Rate) result in costs to non-participating utility customers that are lower than net metering, and are ultimately comparable to the benefits identified.

b. <u>Avoidance of unjust and unreasonable cost shifting</u>

Cross subsidies invariably arise in setting common rates for shared system infrastructure such as the electric power system. While it would be impossible to eliminate cross subsidies entirely, they should be routinely quantified, reexamined, and debated. The Legislature implicitly acknowledged this reality in HB 1116 by referring to the need to avoid only "unjust and unreasonable" cost shifting. The existence of known and ongoing cross subsidies does not diminish the importance of identifying and quantifying new types of cross-subsidies -- particularly those that are fast-growing. At the same time, we must not be overly zealous in focusing on just one cross-subsidy when there may be larger subsidies elsewhere that should also be addressed. In this spirit, the OCA seeks to minimize the cost shift that occurs to nonparticipating ratepayers when customers install distributed generation on their premises, but also do so in a reasonable and measured manner. The OCA estimates that adoption of its Fixed Solar Credit Rate proposal would result in an overall reduction in the near-term cost shift to non-participating ratepayers ranging from 58-66 percent for small systems and 65-71 percent for large systems. This reduction in the cost shift increases to an 84-90 percent reduction over time. Similarly, the DG TOU rate saves non-participating ratepayers at least 50 percent from a comparable net energy metering (NEM) based photovoltaic (PV) system on existing rates. If renewable energy credits (RECs) are exchanged, the cost shift is eradicated all together.

c. <u>Rate effects on all customers</u>

The OCA evaluated the rate impacts to all customers under its Fixed Solar Credit Rate option and compared this to traditional net metering. Over a 25-year period, we estimate that the total state-wide revenue shift (this does not include benefits) to non-participants under the Fixed Solar Credit Rate option to be approximately $81 million for our program compared to $379 million under net metering, thus saving ratepayers just under $300 million. This translates to an average rate increase ranging from 0.4 percent to 0.6 percent and monthly bill increases ranging from $0.18 to $0.25, compared to much higher rate increases under net metering of 2.4 percent to 2.6 percent and monthly bill increases of $1.07 to $1.21.

d. <u>Alternative rate structures including time-based tariffs</u>

The OCA anticipates that residential rates will gradually change in the future and become more time-variant. However, the proliferation of rooftop solar and other customer-sited technologies requires smarter, more accurate rates now, not off in the future. For this reason, the OCA has recommended a time-based tariff option.

e. <u>Generation capacity eligible for new tariff</u>

Abrupt starts and stops in the marketplace are costly, at the same time checkups and adjustments are sometimes needed as situations and technologies evolve. The OCA proposes a five-year solar-specific program to balance these competing forces. In parallel, a time-based DG tariff will also be available and reexamined in every electric utility rate case. To that end, the OCA is hopeful that its solutions make policy confrontations around caps a thing of the past.

f. <u>Size of facilities eligible for new tariff</u>

Similarly to a cap-based program, New Hampshire has previously used system size requirements to determine net metering eligibility. The OCA proposes to identify two classes of project based on system size; systems below 100kW and systems above 100 kW but below 1MW. The current New Hampshire Code of Administrative Rules does not allow for rebates for systems larger than 1 MW. (See Rule Puc 2508.02.) Projects above 100 kW but below 1MW are subject to additional requirements including a certification of compliance a with a 20 percent requirement, a bi-directional meter (as opposed to net meter), and a different crediting mechanism. See RSA 362-A:9.

g. <u>Timely recovery of lost revenue using automatic rate adjustor</u>

Near-term revenue loss from rooftop PV is a reality. A company's residential class revenue requirement is largely based on volumetric sales. Therefore, a sharp decline in usage due to the adoption of a PV system has a direct impact on revenue collection. Utilization of an adjustor that helps recover these lost revenues is appropriate and fair. However, it is in the best interests of all ratepayers that the underlying data informing the revenue loss statistics be based on actual and verifiable data. The OCA is therefore recommending production meters on all PV installations going forward. Such a device allows lost revenue to be recovered in an accurate manner without the administrative burden of a full formal rate case. The OCA continues to support the Lost Revenue Adjustment Mechanism (LRAM) the PUC recently adopted in Docket DE 15-137 as a component of New Hampshire's new Energy Efficiency Resource Standard. However, that is intended as an interim measure. To credit utilities with revenue lost to distributed generation, the deployment and use of production metering should be a requirement going forward.

h. <u>Administrative processes required to implement the tariff and related regulatory mechanisms</u>

The OCA seeks to develop tariffs and policies that impose minimal additional administrative burdens while still meeting all legislative requirements in a way that is fair to all ratepayers. Creating a minimally burdensome administrative process is in the best interests of both the utility and the ratepayers to keep costs and rates low. However, any policy that sends more accurate price signals or attempts to improve upon fixed or inclining volumetric based rates with a net metering overlay will inevitably be more complicated than what is in place today. There is no getting around that reality. Therefore, we must not allow the prospect of setup costs and ongoing administration costs to stand in the way of causing ratepayers to gain a sustainable platform that New Hampshire can use for years to come. In other words, a little investment and time spent getting the right billing, metering, and program structures in place now may save the state from issues down the road and arm it with actionable data to inform future decisions. Therefore, the OCA is recommending production meters on PV systems and the introduction of monetary crediting from the utilities.

i. <u>Time and/or size limited pilots of alternative tariffs</u>

The OCA proposing changes that would place New Hampshire in the middle of the regional pack in terms of DG targets. Moreover, the program that the OCA recommends is a five-year program that can renewed and modified as the PUC sees fit (with stakeholder input, of course). While our proposal targets an initial deployment of 200 MW of new solar DG, we have also demonstrated there is far greater economic potential that could be achieved at a significantly lower cost to all ratepayers than traditional net metering.

VI. <u>Why Change is Needed</u>

Q. Why has the New Hampshire Public Utilities Commission opened this proceeding?

A. New Hampshire utilities rates are in need of modernization, particularly as customers are increasingly exploring distributed generation options. Net metering caps established in 1999 were recently doubled to 100 MW. With the adoption of H.B. 1116, the Legislature and Governor explicitly instructed the PUC to open this proceeding with the intent that the PUC develop new alternative net metering tariff that will avoid the continued policy battles surrounding the previous net metering caps. The Legislature was aware that the orderly process applied by the Commission would give all stakeholders an opportunity to obtain information, exchange ideas and seek consensus in an orderly and fair fashion.

Q. Does the OCA support the spirit of the legislation and goals of this proceeding?

A. Yes, the OCA testified in favor of H.B. 1116 and continues to believe change is needed to accomplish the following:

a. <u>Craft tariffs that provide customers with better, more accurate price signals</u>

Crafting tariffs that allow customer choice and maintain a technology-agnostic approach will create better price signals for all customers. It is important to avoid tariffs that may not be adaptable to future technology development. It is in all ratepayers' interest for this successor tariff to be as future proof as possible and available to other DG technologies. This will limit excessive cost shifts and disruptive policy confrontations. For tariffs that are technology-specific and not linked to system cost drivers, they should be set according to cost-based pricing and evaluated regularly.

b. <u>Create a tariff that is a better overall deal for all ratepayers</u>

The OCA fully acknowledges that cross-subsidies exist throughout our current regulated system and rate designs. As mentioned, these should be routinely quantified, reexamined, and debated. The existence of deeply entrenched cross subsidies does not mean we should ignore new ones that are fast growing. Nor does it mean we ought to be overly zealous focusing on just one cross-subsidy when there may be larger subsidies elsewhere that are equally or more deserving of skeptical reexamination. The cost shift that occurs through DG PV may be small at this time, but this is not a sufficient reason not to start working on addressing the issue.

c. Allow solar customers more options

Customer choice is important to the OCA -- and part of making such choice meaningful is minimizing negative impacts a on non-participating customers. In general, maximizing the extent to which customers have choices with respect to the production as well as the consumption of electricity is inherently good for ratepayers. As long as the choices are well-crafted, the customers use those choices to improve their welfare and optimize their energy use they attain the key benefit that grid modernization provides to the people who ultimately pay for it.

d. Address grandfathering in a fair manner

The OCA believes that the New Hampshire should take steps to avoid issues that have bedeviled other states around grandfathering. The OCA's fixed credit rate proposal just does this while not stifling rate design changes down the road.

e. Create greater access to solar

The current policy arrangement is not ideal for customers who do not own their home or whose homes are not a good fit to benefit from solar. A community solar program as detailed below and in the testimony of Elizabeth Doherty of Vermont Law School, will allow customers who are unable to install solar on their premises to benefit from DG solar technology. The OCA would like to remove as many barriers to access to solar energy for ratepayers are possible.

f. Ensure a sustainable future for solar in New Hampshire

A fair marketplace and predictable policy structure are vital to the future of DG in New Hampshire. The OCA would like to see incremental and gradual progress to sending more accurate price signals to customers, especially those that drive certain cost increases or decreases. In terms of DG, the OCA would like to begin by ensuring that rooftop DG can be a neutral cost proposition for ratepayers as soon as possible. Once that milestone is reached the OCA would like to see DG provide a net benefit to all ratepayers.

VII. Rate Options for New DG Customers

Q. What does New Hampshire statute say regarding the availability of net metering and alternative net metering tariffs for new DG customers going forward?

A: HB 1116 amended New Hampshire law to increase the availability of net metering tariffs by an additional 50 MW (to 100 MW total), stating that this capacity "shall be made available to eligible customer-generators until such time as commission approved alternative net metering tariffs approved by the commission become available."[2]

[2] RSA 362-A:9

Q. How does the OCA interpret this change in the law?

A. The OCA understands this change to mean that new DG systems are eligible for net metering under the current paradigm until the PUC adopts alternative net metering tariffs, at which point new DG systems will only be eligible for these alternatives. The revised statute also gives broad authority to the Commission to modify previously required net metering provisions, stating that "[t]he commission may waive or modify specific size limits and terms and conditions of service for net metering specified in paragraphs I, III, IV, V, and VI [of RSA 362-A:9] that it finds to be just and reasonable in the adoption of alternative tariffs for customer-generators." Through this testimony the OCA is proposing new tariffs that would be available to new DG systems in lieu of traditional net metering tariffs, in accordance with New Hampshire law.

Q. What tariffs options is the OCA proposing for new DG customers in New Hampshire as alternative net metering tariffs?

A. Going forward, the OCA is proposing two potential options as net metering alternatives for customers who are interested in adopting DG.

Option 1: DG Time-of-Use (TOU) (residential only)

Option 2: Fixed Solar Credit Rate

Either of these options could be selected by residential customers as an alternative to traditional Net Metering, which would no longer be available to new DG customers in accordance with H.B. 1116. The OCA proposes that Option 2 (the Fixed Solar Credit Rate) would also be available to non-residential customers and community solar subscribers. I will provide a detailed description of both options in the remainder of my testimony.

Q. Would residential customers who adopt DG be required to select one of these options going forward?

A. Yes. We believe that would be the effect of the Commission's final order in this docket, should the Commission ultimately adopt the two options we are proposing here in response to the H.B. 1116 mandate. That said, if a customer wants to install solar on a traditional rate for self-consumption, that can be allowed as long as any power exported to the grid is compensated at an hourly LMP-linked rate -- i.e., the spot price of wholesale power (the locational marginal price) applicable to New Hampshire as determined by the market administered by the regional transmission organization ISO New England.

VIII. DG TOU (Time of Use) Rate

Summary

Q. Please briefly summarize the OCA's proposed DG TOU Rate option.

A. The OCA is proposing a DG TOU Rate as an alternative net metering tariff that would be available to residential customers installing grid-connected DG systems including (but not limited to) wind, solar PV, and battery storage. Customers on the DG TOU Rate would be subject to a volumetric time-of-use rate that is designed to send more accurate price signals to DG adopters and has an on-peak period aligned with system peak load hours. While each utility has a unique load profile, a period from 2:00 PM to 8:00 PM generally captures the peak load hours for New Hampshire utilities.

Q. What are the basic components of the OCA's proposed DG TOU Rate Option?

A. The OCA's proposed DG TOU Rate option would include the following components:

1. Customer Charge (no change from current utility tariffs)
2. Energy Supply Charge (no change, charge for imported energy, credit for energy exported to grid)
3. TOU Delivery Charge (charge for hourly imported energy, credit for hourly exported energy)
4. Export Charge (charge for hourly exported energy)
5. Partial Non-bypassable Transmission Charge
6. Other Non-bypassable Charges

Q. Is the OCA proposing any changes to the Customer Charge for customers on the DG TOU Rate Option?

A. No. Customers would continue to pay the monthly customer charge specified in each utility's current tariff and, as appropriate, the customer charge as revised at the conclusion of the pending Unitil and Liberty Utilities rate cases.

Q. Is the OCA proposing any changes to the Energy Supply Charge for customers on the DG TOU Rate Option?

A. No. Energy Supply would be treated similarly to the current Net Metering approach. Each kWh generated by a DG customer would yield a bill savings based on the energy supply rate charged on the customer's bill. The OCA is open to making this TOU rate available to customers who use competitive suppliers.

<u>TOU Delivery Charge</u>

Q. Is the OCA proposing any changes to Delivery Charges for customers on the DG TOU Rate Option?

A. Yes. For customers selecting this option, the total delivery charge would consist of two types of charges: a bypassable component and several non-bypassable components. I will describe each of these components in my testimony below.

Q. Please describe the proposed TOU bypassable delivery rate component.

A. DG customers would be charged for kilowatt-hours (kWhs) drawn from the grid (or credited for kWhs exported to the grid) at a cents per kWh rate that varies by time of day. The OCA is proposing an on-peak rate period from 2-8 pm and an off-peak rate during all other hours. Customers would be provided a monetary bill credit for any energy exported to the grid, accounting for the time of day when the exports occurred. This crediting mechanism is similar in many ways to the current net metering paradigm.

Q. What costs does the TOU delivery charge reflect?

A. The delivery rate component under the DG TOU option is based upon the distribution system costs and a portion of retail transmission costs attributable to a typical residential customer.

Q. What is the rationale for establishing an on-peak period from 2-8pm?

A: This time period is intended to be roughly coincident with the typical hours of summer and winter peak demand in New Hampshire and is intended to provide a price signal to customers to reduce demand, or provide distributed generation, during these peak hours. By aligning DG customer rates with system costs, this rate structure is intended to encourage customers to pursue actions that actually reduce costs for all customers, while also ensuring that DG customers contribute to their fair share of fixed delivery costs.

Q. How did the OCA determine that 2-8pm is good approximation of the peak load hours for New Hampshire?

A. The OCA examined the responses provided by Eversource, Unitil, and Liberty to Data Request OCA 1-3 to determine the hours in which system load was within five percent (5%) of the annual system peak for each utility. For each utility, these hours all occurred during summer months (July-Sept). The frequency of these occurrences is summarized in the table below:

Hour Ending	**Number of Occurrences within 5% of Annual Peak Load (July 2013 - July 2016)**			
	Eversource	**Liberty**	**Unitil[3]**	**Sum**
12:00	0	1	0	1
13:00	6	3	4	13
14:00	17	9	4	30
15:00	19	10	4	33
16:00	20	8	3	31
17:00	18	7	2	27
18:00	16	4	0	20

[3] In their responses to OCA 1-3, Eversource and Liberty provided information for all 8760 hours of the year, while Unitil provided information only for peak days. Thus, for Unitil the counts presented in this table do not include any hours on non-peak days that were also within 5 percent of the annual peak.

19:00	12	0	0	12
20:00	2	0	0	2
Total	110	42	-	

Table 1: *Number of Occurrences within 5% of Annual Peak Load*

Q: What does the OCA conclude from this analysis?

A. Over the last three years, the hours in which customer demand has been at or near the system peak tends to occur between 1pm and 6pm in the summer months. However, this analysis omits any consideration of peak demand in the winter, which is also a major concern for New Hampshire and other New England states.

Q: Did you conduct any analysis of winter peak demand for a New Hampshire utility?

A: Yes. We examined hourly system load data for Eversource during all winter months (Dec-Feb) within the last three years. We determined that nearly every hour within 5 percent of the monthly peak during these months fell between 4pm and 8pm, with only one exception. Thus, we conclude that winter peak demand generally occurs between the hours of 4pm and 8pm.

Q: Based on this analysis of both summer and winter peak demand hours, how does the OCA recommend the time-varying component of the DG TOU rate be structured?

A: The OCA recommends that the on-peak hours for the rate occur between 2pm and 8pm. We believe this time period sufficiently approximates the hours when the system experiences high demand, regardless of the season. Additionally, we believe that this provides a sufficiently narrow time window that customers will be able to respond effectively to on-peak and off-peak price signals. Finally, we believe this time period is sufficiently balanced to ensure that DG customers contribute an appropriate share of their fixed cost responsibility.

Q: Why not create a unique peak time period for each utility?

A: As New Hampshire transitions to a new rate structure for DG customers, we believe establishing a common time period will help to eliminate confusion and provide simplicity to new DG customers. However, the OCA is open to utility-specific modifications in the future.

Non-bypassable Charges

Q: Please describe the non-bypassable charge components for customers on the DG TOU Rate option.

A: Customers on the DG TOU Rate option would be subject to the full set of existing energy-based non-bypassable charges (i.e. stranded costs, system benefits, external delivery charge, storm recovery, and electricity consumption tax). In addition, these customers would also be responsible for a new non-bypassable partial transmission charge.

Q: How would this charge be computed?

A: The non-bypassable charge components would apply to the gross kWh energy consumed by DG customers prior to any reductions or netting from energy produced by a DG system. Since both DG production and customer net load will be metered, the gross customer load (i.e. load without DG) can easily be computed for the purposes of computing the non-bypassable charges.

Q: What is the rationale for collecting existing non-bypassable charges (e.g. stranded costs, system benefits, etc.) from DG customers in the manner described?

A. According to New Hampshire law, it is illegal for customers to bypass these charges[4]. However, DG customers with net metering can currently avoid paying them in part or in full. This is true even though the applicable costs are not avoided by distributed generation and are therefore likely to be recovered from non-participating customers. It is inequitable for non-participants to be burdened with an increased share of these costs while DG customers do not. Moreover, in some cases, such as the system benefits charge, DG customers are still able to participate in efficiency programs and are still beneficiaries of the public benefits they produce. For these reasons, the OCA believes it is fair for utilities to fully recover non-bypassable from DG customers based on gross kWh consumption.

Q: Please explain the rationale for designating a portion of transmission costs as non-bypassable for DG customers.

A. For New Hampshire utilities, retail transmission rates are based on several categories of wholesale transmission costs necessary to support the ISO-NE regional transmission system. Most of these wholesale costs are assessed to each utility by ISO New England based on their monthly peak load. Over the course of a year, DG customers are likely to produce energy during times that can reduce their contribution

[4] RSA 374-F:3

the utility's monthly peak loads but not eliminate it entirely for all months of the year. The non-bypassable component reflects any remaining DG customer load that is coincident with the monthly peak but is not fully offset by DG.

Q: What is the current retail transmission rate for residential customers of New Hampshire utilities?

A: Retail transmission rates range from 2.39 ¢/kWh (Eversource) to 1.786 ¢/kWh (Liberty).

Q: What portion of this retail transmission rate does the OCA propose to be non-bypassable?

A: Based on our analysis we propose that the non-bypassable portion should be approximately 50 percent of current retail transmission rates (~1 ¢/kWh). However, it may be appropriate to reduce the non-bypassable transmission charge for DG customers who are able to further decrease load during monthly peaks (e.g. through the incorporation of energy storage).

Q: How did you approximate the non-bypassable component of transmission charges attributable to DG customers?

A: The OCA conducted a three-step analysis. First we examined historical monthly peak load data for ISO-NE in 2015 using the Net Energy and Peak Load report.[5] We used this information to approximate the hours when monthly peak load is likely to be highest for a New Hampshire utility. Second, we examined the 8760 hourly load profile for a sample of New Hampshire residential customers using the data provided by Unitil

[5] Net Energy and Peak Load Report, 10/07/2016, https://www.iso-ne.com/static-assets/documents/2014/09/enepk_report.xls

in response to TASC 2-2. We then used this information to calculate the change in the average customer's load that would result from the installation of a 6 kW rooftop PV system. Solar PV output was estimated using the PV Watts software tool. Finally, we identified the change in customer load during the monthly peak hours. Over the course of a year, we found the average reduction in peak load to be 50 percent.

<u>Export charge</u>

Q: What is the purpose of the proposed export rate component of the DG TOU Rate option?

A: The export charge is intended to appropriately recover the fixed costs associated with the portion of the utility-owned distribution grid accessed by DG customers when energy from DG systems is being exported.

Q: Generally speaking, does the OCA believe DG customers are willing to pay an additional fee for grid services they presently receive?

A: Yes. In fact, the Smart Grid Consumer Collaborative recently conducted a national survey of 1571 customers -- most of which had adopted solar PV or EV technology -- and found that about 60 percent of PV adopters were willing to pay over $25 per month for grid backup service.[6] A 5.5 kw DC system paired with an average Eversource customer load yields approximately $11 per month for the grid usage/storage fee.

[6] http://smartgridcc.org/research-release-sgccs-consumer-driven-technologies-study/

Q: How does the OCA propose the export rate be determined?

A: The OCA proposes that the export rate be based upon the portion of the standard residential delivery rate related to secondary distribution system costs.

Q: What is the rationale for basing the export rate on secondary distribution system costs?

A: To date, DG penetration remains relatively low on New Hampshire utility distribution systems. Thus, it is likely that energy produced by and exported from DG installations is limited to the secondary distribution system and would be consumed before it is exported the primary distribution system. The export rate is intended to recover costs utility incurs for DG customers to both access and benefit from use of the secondary distribution system.

Q: Has the OCA estimated what the export rate should be under this proposed approach?

A: Yes, approximately ~$0.04 per kWh on an hourly basis. The OCA has examined recent embedded cost of service studies (COSS) conducted by multiple New Hampshire utilities to determine what portion of the residential class revenue requirement was related to primary distribution system costs versus other costs (i.e. secondary distribution, billing, metering, etc.).[7] Based on this analysis the OCA concludes that the primary distribution system comprises approximately 45 percent of total distribution related delivery costs.

[7] Unitil 2016 Rate Case, DE 16-384: Eversource 2009 Rate Case, DE 09-035.

Thus, under the OCA's proposal, the export rate blended with self-consumption would equal approximately 55 percent of distribution-related delivery costs. This would equate to ~$0.02 per kWh for a typical New Hampshire utility. This rate is set on the expectation of around 8,000 kWh of annual usage. However, the average DG customer only exports half that amount. Thus, assuming that a typical DG customer exports 50 percent of energy produced to the grid, an export rate of ~$0.04 per kWh should be sufficient to recover costs of the secondary distribution system.

Q: Is this fair?

A. Very much so. The peak hours of the TOU rate are based on system peak not individual feeder peak. Peak times for residential customers tend to be much later in the day during the latter half of the 2-8 PM peak window. This means that the TOU rate may overcompensate exports during the early peak hours.

Q: Doesn't a solar customer rely on the grid 24/7 even during times of self-consumption?

A. Yes, but this rate is intended to be technology agnostic. Meaning load reducing energy efficiency measures (when coupled with DG) and energy storage are eligible for this rate. These technologies do not share the intermittency of PV and the rate design should not treat them as such. It is a balancing act. Moreover, at low penetrations there are likely some, though perhaps small, savings with PV on the local distribution system.[8] In the end, the issue stems from the current system of volumetric based revenue recovery. The OCA recognizes this and is open to three-part rate pilots provided the

[8] Impact of High PV Penetration on Distribution Transformer Insulation Life, IEEE https://www.researchgate.net/publication/275833500_Impact_of_High_PV_Penetration_on_Distribution_Transformer_Insulation_Life

demand charge is limited to narrow peak time windows and is coupled with consumer education and the acquisition of actionable data.

Q: Has the OCA estimated what the rate design for each utility should be under this proposed approach?

A. Yes, as mentioned I took the top system peak hour and the 5 percent of hours within that one peak hour to set the time frame. I then loaded the vast majority of delivery charges within that peak window. This needed to be done because supply is applied on a flat volumetric basis leaving only delivery to send peak price signals. Ideally, one would not have to use delivery rates solely to send the peak price signal but the current system requires it. The outcome of this approach is present in the chart below. This an approximation based on the small sample size of residential customer load data provided by the utilities. Given the small sample size and rounding the chart below is meant to be illustrative rather than specific.

($/kWh)	Eversource	Liberty	Unitil
Monthly Charge	$12.89	$12.12	$10.27
Energy Service (default)	$0.1095	$0.0922	$0.0769
T&D On Peak (2 PM-8 PM, 365 days)	$0.1900	$0.1850	$0.1950
T&D Off Peak	$0.0015	$0.0015	$0.0015
Hourly Export Charge	~$0.04	~$0.04	~$0.04

Non-bypassable Partial Transmission Charge	~$0.01	~$0.01	~$0.01
Other Non-bypassable Charges:	Stranded Costs, System Benefits, Storm Recovery, Electricity Consumption Tax, etc.		

Table 2: *Illustrative Rate Design for Each Utility*

Q: Please briefly summarize which charges and/or credits would be in effect for a typical DG customer over the course of the day.

A: The chart below provides an overview of the different charges and credits contemplated, indicating the portion of the load or generation to which each is applicable.

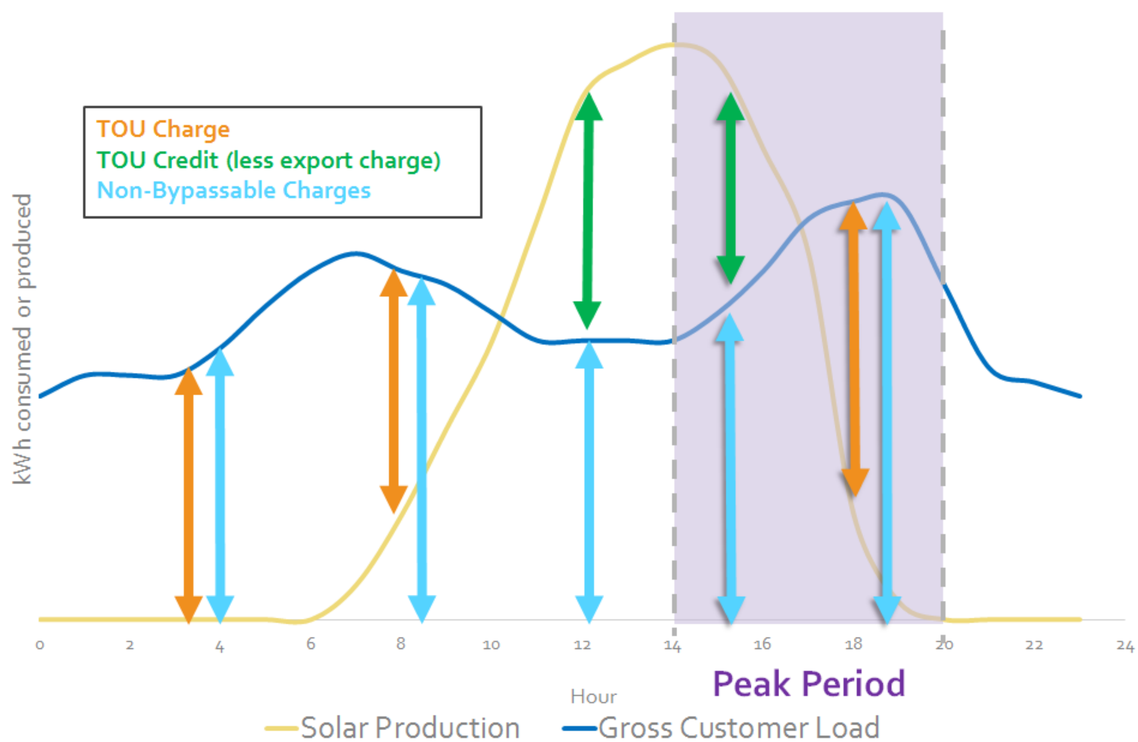

Chart 1: *Illustrative Example of Charges and Credits for a Typical DO Customer*

Q: Do all these features of the TOU rate short change solar adopters that do not wish to engage in additional peak load reduction?

A. Not at all. The blended compensation/offset rate for standard south facing solar PV on the TOU is fairly aligned with the value of solar (mentioned later in the testimony), not intentionally, but naturally because the rate sends more accurate price signals. While it is true that solar adopters who face panels west or incorporate peak load reduction measures may receive an increased level of compensation, those actions are not necessary if one does not wish to pursue those pathways. Regardless, the DG TOU rate encourages less use of the grid and system right sizing.

Q: Should DG customers be required to install a production meter?

A: Yes. The OCA believes this is necessary to mitigate the present risk that multiple claims are being made for the renewable attributes of DG facilities. Pursuant to RSA 362-F:6, II-a, electricity providers in New Hampshire may claim a Class II REC credit for customer-sited generation sources that are net metered but for which Class II certificates are not issued. Over the last year, there appears to have been a substantial increase in the number of DG facilities that fall within this category. As reported in the PUC's recent Renewable Energy Fund Annual Report[9], ACP revenues declined from 2014 to 2015, reversing the trend from the previous year. The report states that, "The reduction in ACPs may be due in part to the significant increase in solar PV installations and a credit for Class II net metering." The PUC currently reports about 19 MW of customer sited sources providing Class II credit in this way.[10] The OCA is concerned that both the utility and customer may think and claim they have "gone 100 percent solar." This problem can

[9] NH Public Utilities Commission Renewable Energy Fund Report, October 1, 2016.
[10] http://www.puc.state.nh.us/sustainable%20energy/renewable_portfolio_standard_program.htm

be alleviated by installing a meter that would be able to verify production and allow these customers to generate RECs.

Q: Would DG customers have the option to retain the Renewable Energy Credits generated?

A: Yes. In accordance with RSA 362-F:7, customers will have the option to retain RECs generated from DG facilities to be retired or sold at a later date. Customers who select the DG TOU option will also have the option to transfer their RECs to the electric distribution company in exchange for not being subject to additional rate changes for a period of 20 years (i.e. these customers will grandfathered into the DG TOU rate “as is”).

Q: If customers transfer RECs (in exchange for future certainty), does this provide a benefit to non-participating customers?

A: Yes. Utilities that obtain Class II RECs this way will be able to use them towards their Class II RPS compliance, thereby reducing the need for additional REC purchases or ACP payments. In the event that New Hampshire utilities no longer have a need for Class II RECs, they could also be sold to another jurisdiction, thereby providing a revenue source that could also benefit non-participating customers. In fact, REC exchange would render the TOU rates cost neutral and in some cases a net positive to non-participants on day one. This outcome would eventually be realized in the future for those that do not exchange RECs as the TOU rate design updates to better reflect system and market dynamics.

Q: How should incremental metering costs be treated?

A. The OCA believes that the additional metering costs should be split between the DG adopter and the utility (i.e. all ratepayers) if administratively straightforward. Both are benefiting from the more advanced metering and with the production meter non-participants have accurate lost sales data and in the field production data. In fact, a TOU rate in Arizona was just approved with a lower fixed charge than the standard residential rate to encourage adoption on that rate despite the same or greater metering costs.[11]

Q: Can non-DG customers be on this TOU rate?

A. The OCA is open on this point. A pilot program would be appropriate but customers would have to stay on the rate for a full year to avoid gaming.

Q: Is the OCA open to adding seasonal differentiated pricing?

A. Yes, down the road once more experience is gained with more basic TOU rate designs. The is also openness to real time pricing constructs.

Q: Would there be a limit to the number of new DG customers that could participate in the OCA's proposed DG TOU Rate option?

A: Presumably, the rate would be examined in upcoming rate cases, so if any issues arise that would be the best forum. However, it may be sensible to include some safeguards to limit excessive procurement of DG resources through the DG TOU rate. Thus, the OCA is open to limiting participation on the DG TOU Rate option to a specific MW capacity limit. This MW capacity limit could be equal to the unsubscribed portion of the current 100 MW net metering cap remaining at the time of a Commission order in this proceeding, plus an additional amount of MWs.

[11] Docket No. E-04204A-15-0142, In the Matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates … Decision No. 75697, http://images.edocket.azcc.gov/docketpdf/0000172763.pdf

IX. Fixed Solar Credit Rate

Purpose

Q. Please summarize the OCA's proposed Fixed Solar Credit Rate option for new DG customers.

A. The Fixed Solar Credit Rate provides New Hampshire utility customers with a second alternative net metering tariff option that is designed to compensate customers for energy produced by new PV DG systems. This compensation is not linked to the utility's retail rate but, instead, is provided through a monetary bill credit for DG energy production based on a delivery credit rate that is fixed for a 20-year period. DG customers selecting this rate option will also continue to receive full retail rate credit for the energy supply portion of their bills. As more systems are installed across the state, and as installation costs decline, the delivery credit rate will gradually decline for new customers.

Q. What is the purpose of the Fixed Solar Credit Rate option?

A. This option is intended to allow New Hampshire's DG industry to continue its growth and mature by providing increased certainty and sufficient compensation to DG customers and installers, while also capturing additional value and cost savings for non-participating utility customers over time.

Q. What level of growth in New Hampshire's DG industry does the OCA expect can be achieved through this option?

A. Under this proposal, the OCA estimates that New Hampshire can obtain at least 2.70 percent of its electricity (as a percent of retails sales) from DG solar resources by

2022, at a substantially reduced cost to customers when compared to full retail rate net metering. This equates to approximately 200 MW of incremental new DG solar systems.[12]

Q. How does a goal of 2.7 percent compare to other states in the region?

A. Several states in the northeastern U.S. have established solar or distributed energy procurement goals either as part of a larger renewable portfolio standard, or as a standalone procurement goal. An aspirational solar procurement goal of 2.70 percent of retail sales would align New Hampshire with the trajectories of other nearby states. The chart below shows a comparison between the proposed goal of 2.7 percent and other procurement goals for states in the region.

[12] Assumes retail sales of approximately 11,790 GWh in 2022 and a statewide capacity factor of 13.9 percent for distributed solar resource production, and 60 MW of solar DG that is existing or under development.

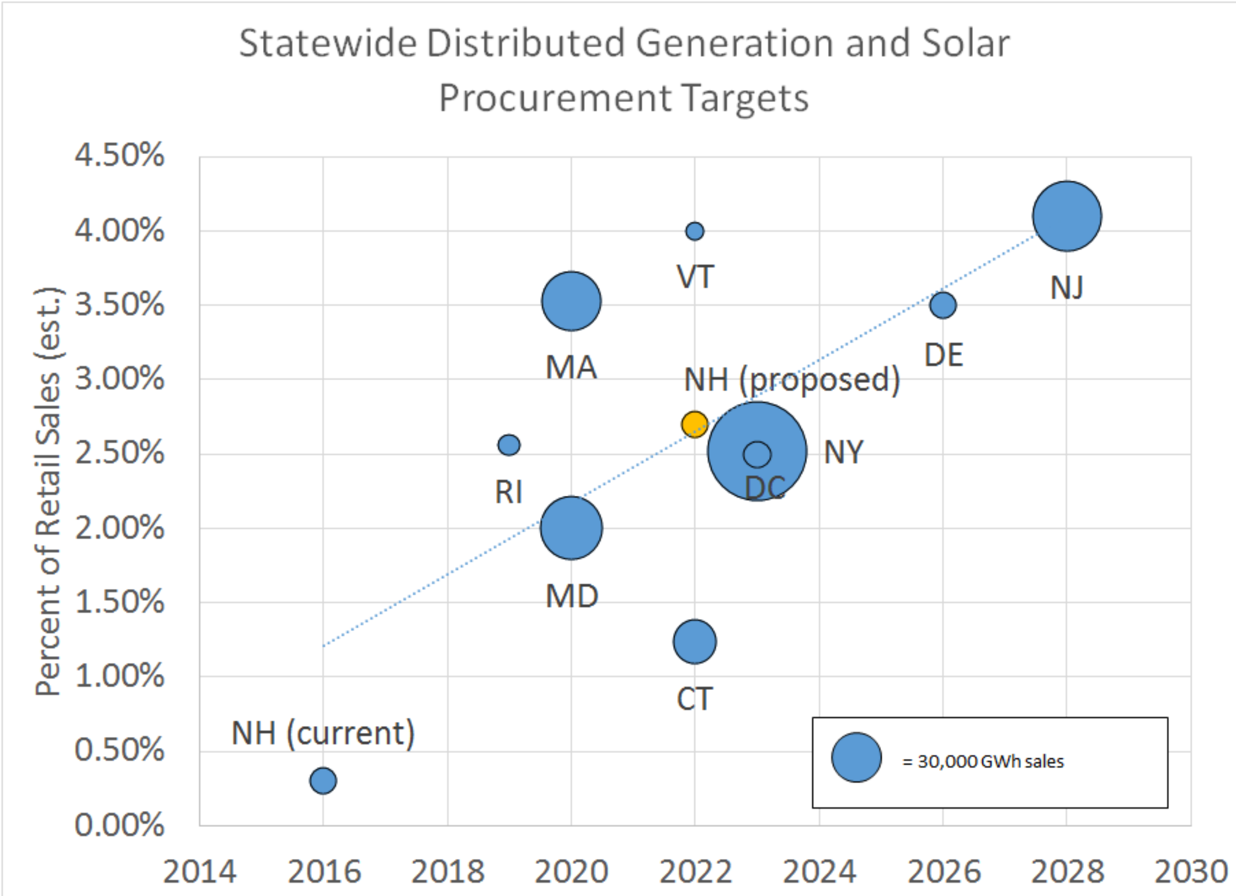

Chart 2: *Comparison of Statewide Distributed Generation and Solar Procurement Targets*

Program Design

Q. Who will be eligible for the Fixed Solar Credit Rate option?

A. This option will be available to residential and commercial customers that install PV DG systems on their premises, as well as customers that subscribe to community solar.

Q. Will there be a limit on the total amount of DG eligible for the Fixed Solar Credit Rate option?

A. The OCA proposes that this option be initially limited to 200 MW total: 75 MW for Small Scale DG systems (≤100 kW) and 125 MW for Large Scale systems (>100 kW). As a safeguard against excessive cross-subsidies, and to help manage the growth of the program, a cap could also be established within each specific utility service territory. This would also help to minimize the potential that MWs contributing towards the statewide goal would be too heavily concentrated in one area. The total MWs of the cap could be allocated to each utility similarly to the way it is currently allocated for net metering as illustrated in the table below:

Segment	***Eversource (78%)***	***Unitil (13%)***	***Liberty (9%)***	***Statewide Total (100%)***
Small Scale (≤100 kW)	*58.5*	*9.75*	*6.75*	*75*
Large Scale (>100 kW)	*97.5*	*16.25*	*11.25*	*125*
Total	*156*	*26*	*18*	*200*

Table 3: *Proposed MW Cap for Each Utility*

Q. How will the credit rate be established?

A. A different mechanism will be used to establish the credit rate for Small Scale and Large Scale DG systems. For Small Scale DG systems (≤100 kW), the credit rate will be prescribed in advance through a capacity-based tranche step-down mechanism. For Large Scale DG systems (>100 kW) the credit rate will be established through an auction mechanism. Community solar systems will also be eligible for specific modifications to the credit rate. I will describe both mechanisms in my testimony.

Q. As proposed, the Fixed Solar Credit Rate would apply to all production, not just exports?

A. Correct. However, the OCA may be open to an option that allows the credit rate to only apply to exports.

Q. Could the credit rate offset the fixed customer charge?

A. That is conceivable with a large enough system.

Q. Do credit roll over month to month?

A. Yes, just like current rules, excess generation rolls over indefinitely as a credit on a customer's bill. A customer may choose to receive payment for excess generation at an avoided cost rate at the end of the year. (See Puc 900.)

Q: Although the primary purpose is focus on solar PV, is the program structure able to adapt to market developments and technological innovation?

A. Definitely. The structure is very flexible to accommodate new policy directions, technology, locational data, etc. Unlike net metering, the Fixed Solar Credit Rate can accommodate the following: Locational value, technology (west facing, advanced inverters), state policy goals that guide the capacity targets, and reliability adders can be integrated into credit rates. Regular check-ins can occur at Commission discretion to respond to changing market conditions and technological developments.

<u>Small Scale DG</u>

Q. Please describe the proposed crediting mechanism for Small Scale DG systems (≤100 kW).

A. For Small Scale DG systems, the credit rate will be established in advance through a series of tranches, with each tranche representing an amount of incremental DG capacity (in MWs) installed statewide. A utility customer in New Hampshire who installs a new DG system and selects this option will be eligible for the 20-year credit rate associated with the prevailing tranche. Once a tranche becomes fully subscribed, new DG customers would be eligible for the next tranche in the series.

Q. Would DG customers be issued renewable energy certificates (RECs) under this option?

A. Yes. As required by statute, DG customers would have the option to retain RECs produced by their DG systems to be retired or sold at a later date. Customers would also have the option to transfer their RECs to the distribution company in exchange for a supplemental credit rate.

Q. What tranches does the OCA propose for Small Scale systems?

A. The OCA's proposed tranches are summarized in the table and corresponding chart below.

Tranche	***Incremental MW (Small Scale, <100 kW)***	***Cumulative MW Installed***	***Delivery Credit Rate, ¢/kWh (RECs retained by customer)***	***Delivery Credit Rate, ¢/kWh (RECs transferred to distribution company)***
1	5	5	4	7
2	8	13	3.5	6.5
3	11	24	3	6
4	14	38	2.5	5.5
5	17	55	2	5
6	20	75	1.5	4.5

Table 4: *Proposed Tranches for Small Scale Systems*

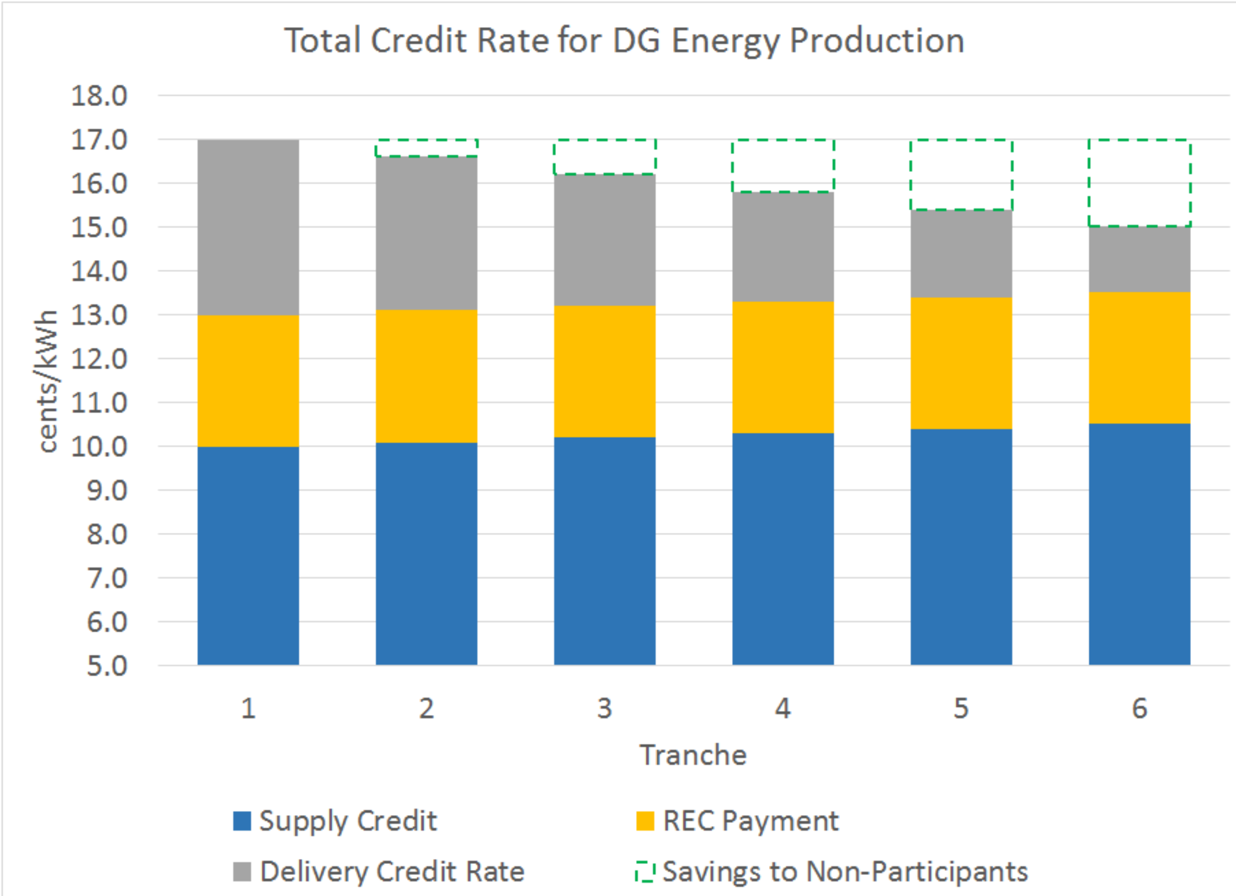

Chart 3: *Proposed Tranches for Small Scale Systems*

Q. What considerations did the OCA take into account when developing these tranches?

A. The OCA considered a variety of factors including 1) the economic viability and market potential for future DG deployment in New Hampshire and 2) rate impacts to non-participating customers.

Q. How did the OCA consider economic viability for DG customers?

A: The OCA conducted a financial analysis to determine whether the proposed Delivery Credit Rates would be economically viable for prospective DG customers in a variety of small scale PV market segments. The financial analysis was conducted using the Cost of Renewable Energy Spreadsheet Tool (CREST) developed by Sustainable Energy Advantage (SEA) for the National Renewable Energy Laboratory (NREL). This analysis considered a variety of key factors including the federal investment tax credit schedule, investor and customer financing expectations, and future technology cost declines. Using this approach, the OCA was able to tailor the Delivery Credit Rates to ensure that there would be sufficient incentive for continued adoption of DG systems.

Q. How did the OCA consider market potential for DG customers?

A: The OCA contracted with Sustainable Energy Advantage to conduct a market potential study for small scale solar PV in New Hampshire under the proposed tranche levels. This study is attached to my testimony as Exhibit 2. The study estimated both the technical potential for solar DG deployment and the economic potential in New Hampshire at the proposed Delivery Credit Rates under a scenario where each tranche is in effect for a single year. This analysis confirms that there is substantial economic potential for DG deployment at the proposed credit rates and that they would incentivize deployment in all market segments. [13] In fact, SEA found a total economic potential of 653 MW of DG at the proposed tranche levels, representing 84 percent of the total technical potential and significantly more than the 200 MW goal that we are initially proposing.

Q. Did the OCA consider the impact that these credit rates would have on avoidance of cost shifting and subsequent rate effects on all customers?

A. Yes. The OCA conducted an analysis to determine the impact to non-participating customers. The OCA anticipates that if DG customers adopt this rate

[13] Given the significant economic potential, OCA notes that it is possible the tranches would be deployed sooner than 2022, thereby achieving the DG policy goal ahead of schedule.

option, there would be a substantial reduction in the cost shift present under traditional net metering. For small scale systems, OCA estimates an overall reduction in the near-term cost shift to non-participating ratepayers ranging from 54-66 percent (depending on utility) in Tranche 1 and increasing to 84-88 percent in Tranche 6. For Large Scale systems, the reduction in the cost shift is anticipated to begin at 65-71 percent and increase to 88-90 percent, depending on the competitiveness of auction prices.

Q. Is there still a cost shift at the last tranche?

A. Not necessarily. While a small short term cost shift still exists because of the remaining ~1.5 cent/kWh amount of delivery in the credit, there may be some longer-term benefits to the distribution system that overtake those near-term cost shifts to create a net benefit. There may also be some O&M (operations and maintenance) savings in the near term.

Q: What should happen if all the tranches becomes fully subscribed?

A: Additional tranches could be added at a later date. The OCA recommends that the PUC and other stakeholders closely monitor the deployment of DG under this policy framework. As tranches are filled, the PUC should revisit this issue to determine whether the tranches framework should be extended or otherwise modified. Also, as the market moves through the existing tranches, the PUC would notify stakeholders about any impending transition to the next tranche.

Q: What if there is no renewal?

A. First, the difference between the last tranche's level of distribution credit and no distribution credit does not represent an insurmountable chasm. In fact, segments of the DG market will likely be transacting without any distribution credit before the general market even hits the last tranche. The design of the program (e.g. place more MWs at lower credit levels) attempts to scale the DG market so it can become self-sufficient of delivery credits. Second, The OCA anticipates, and in fact, encourages New Hampshire utilities to pursue aggregation pilots for DG facilities. This may open doors to market revenue and increase economic benefits to ratepayers. If perfected by the time the last tranche is filled, this could be an additional avenue to propelled DG forward. Third, the OCA fully expects there to be a DG TOU rate available for customers.

<u>Large Scale DG</u>

Q. Please describe the proposed crediting mechanism for Large Scale DG systems (>100 kW)?

A: Like Small Scale systems, Large Scale DG systems would be credited at a fixed rate for 20 years. However, instead of prescribing the credit rate in advance, credit rates would be established through a simple reverse auction process administered by the PUC. The OCA does not envision this to be a large and cumbersome process and believes it could be accomplished through a simple project scoring spreadsheet.

Q. Is there precedent for this type of reverse auction process for projects between 100 kW and 1000 kW?

A: Yes. Arizona Public Service employed this process for its commercial PV incentive program.[14] The OCA envisions a similar process as follows: 1) The PUC would stipulate a maximum credit rate and size of the auction round; 2) Project developers would enter information into the ranking spreadsheet including technology type, system

[14] For more details see: http://www.nrel.gov/docs/fy13osti/56308.pdf

size (kilowatts DC), estimated annual production (kWh), the total project cost, and the requested credit rate (up to the maximum); 3) The spreadsheet would calculate a score for the project primarily based on the credit rate; 4) After all proposals are received, credit rates would be assigned starting with the lowest bid, until the capacity for the auction round is exhausted.

X. Community Solar

Q: Has the OCA considered the potential for community solar to participate under its proposal?

A: Yes. We believe community solar could comprise significant part of New Hampshire’s DG market under our proposal and there are many reasons why this could be beneficial.

Q: Ideally, how would community solar customers participate under OCA’s proposal?

A: Customers who become subscribers of community solar could be eligible to receive a monetary bill credit through the Fixed Solar Credit Rate option. This would be a significant improvement upon the current system which is administered in a way that is taxable to subscribers.

Q: How would the credit rate be established for community solar customers?

A: The credit rate would be established through the same mechanism as residential and commercial systems. For Small Scale community solar systems, the credit rate would be determined through the tranche mechanism. For Large Scale community solar systems, the credit rate would be determined through the auction process.

Q: Does OCA propose any adjustments to these credit rates that would be specific to community solar?

A: Yes. OCA through Vermont Law School proposes that community solar credit rate could be adjusted to include two potential adders: 1) an environmental benefits adder and 2) a low and moderate income adder.

Q: What is the rationale for including these adjustments?

A: This issue is addressed in the testimony of Elizabeth Doherty.

XI. <u>Implementation Details</u>

Q: Will implementation of the OCA's options require time and resources?

A: Any scalable policy framework will require an upfront investment of time and resources. While the current system is simple, it does not send accurate prices signals, there is no data collection or verification, non-solar ratepayers see no benefit in technology cost declines, and the policy is not sustainable politically or financially. A system that fixes this will be worth the investment. The OCA's proposal requires monetary crediting, billing system updates to apply those credits, as well as general implementation expenditures. The OCA is open to implementation suggestions that streamline, simplify, and reduce these costs. For example, some of the costs can be defrayed by applications fees and deposits. Regarding timing, the DG TOU rate may require more time to implement than the Fixed Solar Credit Rate. The OCA is flexible in terms of timing, as the new options do not necessarily have to become available simultaneously. Finally, implementation methods may differ by utility, the OCA is open to each utility finding the best process that works from them.

Q: Could this TOU rate work for commercial?

A. Yes, however the eligible technology list may need to be modified to avoid any unforeseen impacts. The main technologies for the residential market revolve around solar, wind, and eventually batteries. Given the scale and sophistication of commercial customers, there can be many more options.

Q: Does DG solar on the TOU rate count toward the tranches of the Fixed Solar Credit Rate?

A: No, they are separate programs.

Q: Is the OCA making any changes to the Up-front Incentive program?

A: Not at this time.

III. Value of Solar

Q: In the development of this proposal did OCA consider a range of potential costs and benefits produced by customer-generator facilities?

A: Yes. OCA conducted a preliminary “value of solar” analysis to understand the potential costs and benefits of energy generated by distributed solar facilities. The categories of benefits and costs we considered include:

- Avoided wholesale energy costs (including line losses)
- Avoided wholesale capacity costs

- Avoided RPS compliance costs (i.e. REC prices)
- Avoided transmission costs
- Market price effects (DRIPE)
- Integration Costs

Our analysis did not include any avoided distribution system costs as these are highly location-specific and difficult to quantify. Our analysis also did not include other possible societal benefits such as avoided air emissions, avoided fuel price uncertainty, benefits to the local economy, etc. The preliminary analysis indicates potential monetizable benefits from DG solar of approximately 13-15 cents/kWh. The OCA is still refining this analysis and is open to additional input and information from other stakeholders. Additionally, in accordance with the principles outlined in this testimony, the OCA believes that this value analysis, while informative, does not necessarily reflect the price that all customers should pay to receive these benefits.

Benefit Categories	***Low Case ($/kWh, first-year avoided costs)***	***High Case ($/kWh, 20-year levelized avoided costs)***
Energy	$ 0.048	$ 0.083
Capacity	$ 0.012	$ 0.016
RPS	$ 0.050	$ 0.038
Market Price Effects	$ 0.008	$ 0.001

Transmission	$ 0.012	$ 0.012
Integration Costs	$ -0.002	$ -0.005
Total	**$ 0.128**	**$ 0.145**

Table 5: *Costs per Benefits of DG*

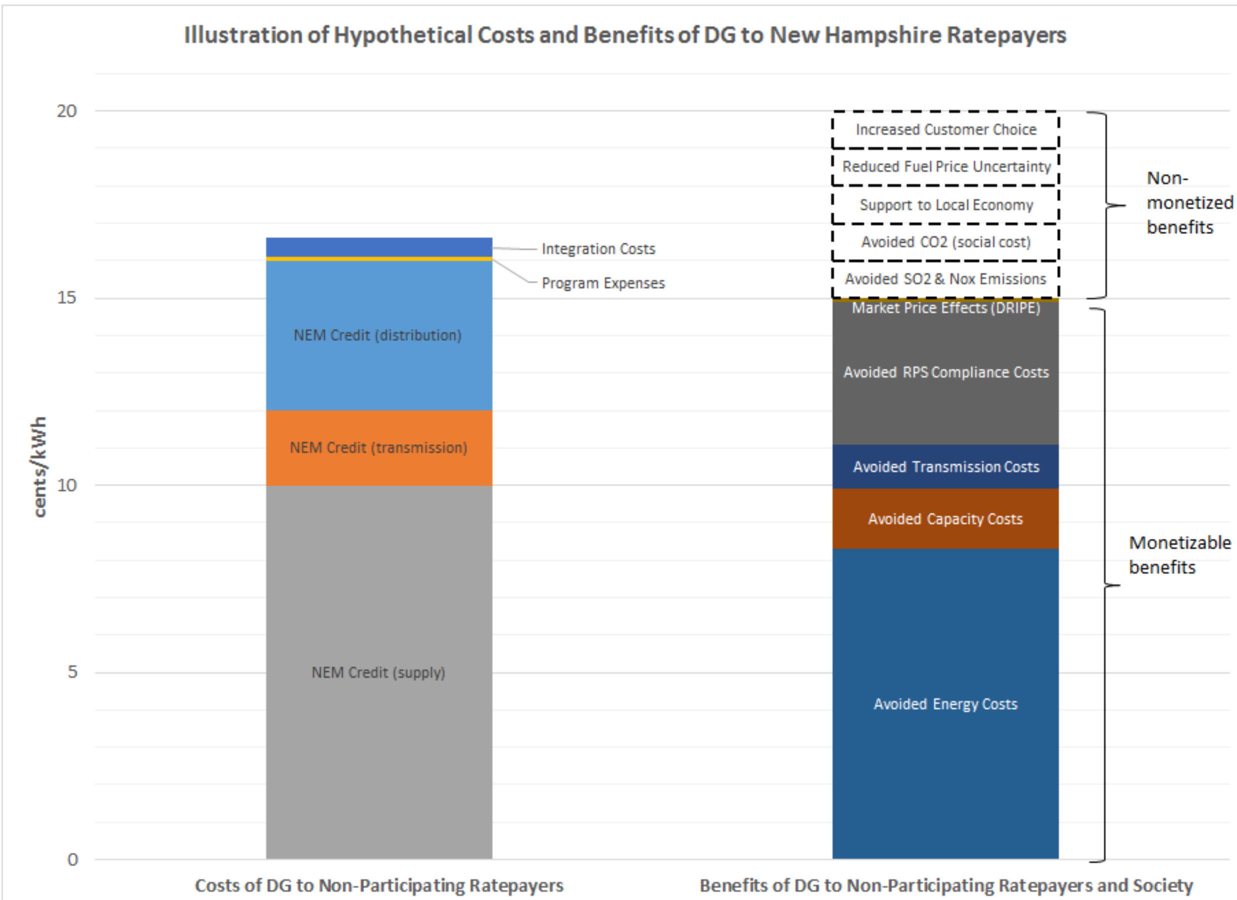

Chart 4: *Illustrative Costs and Benefits of DG. Non-monetized benefits were not quantified and are included only as placeholder values.*

Q: Should solar production be compensated at the valuation rate?

A: Not necessarily, especially when solar can be built at a compensation rate less than value. If one pays the exact value (even if that value if derived from a conservative methodology) there are no savings to non-participants, who are therefore economically indifferent. A win-win in the DG space can occur when merging traditional cost-based approaches with value-based compensation. In other words, if solar can be built for less than its value to the grid, then the adopter wins and other ratepayers win. The Legislature's expressed concern about unfair and unreasonable cost-shifting is addressed via a compensation regime that provides benefits to all. The Fixed Solar Credit Rate provides a glide path to such an outcome. The DG TOU rate also makes strides towards this goal.

Q: Have experts weighed in on this?

A: Yes. James Bonbright and the co-authors of the revised edition of the often-cited Principles of Public Utility Rates argue that "[value-of-service standards] play important though subordinate roles [to cost] in the modern theory and practice of rate regulation.".[15] In sum, value should be a consideration but the amount one pays should be as cost based as possible. This is especially true for non-fuel, fixed infrastructure like investments such as PV solar.

Q: Does this conclude your testimony?

A: Yes it does.

[15] Bonbright, et at. Principles of Public Utility Rates, 2nd Ed., page 137

Exhibit 1:

Lon Huber Resume

LON HUBER

Email: lhuber@strategen.com

Expertise: Energy markets, policy analysis,
distributed energy resources, and consumer advocacy.

Experience

Director of Strategen's Private Sector Consulting Practice March 2015 – Present
Strategen Consulting, LLC – California
Strategen is a strategic consulting firm that develops tailored solutions for governments, utilities, and corporations - empowering them with the insight they need to create sustainable value for their investors, customers, and ratepayers.

- Responsible for Strategen's fast growing public sector consulting practice.
- Frequently cited in trade press and a regular speaker at NARUC and NASUCA conferences.

Advisor to the Director April 2013 – March 2015
Residential Utility Consumer Office (RUCO) – Arizona

- Responsibilities: policy analysis and design, advocacy, case testimony, constituent outreach, and financial analysis.
- Team lead on net metering, utility-owned rooftop solar, utility merger, and new resource procurement policies.

Founder February 2010 – December 2014
Next Phase Energy – Arizona

- Business provided project management, consulting, and financial modeling work.
- Clients included solar companies, state utility commissions, public advocate offices, city governments, and utilities.
- Partnered with DOE, Arizona Governor's office, and Tucson Electric Power on home energy management projects.

Manager September 2011 – December 2012
Suntech America – California

- Point person for the company in every key state solar market except California.
- Worked to balance cost effective utility-scale solar with state distributed generation policy goals.
- Elected by SEIA member companies to be the state lead in Arizona.

Finance Development Coordinator September 2010 – September 2011
TFS Solar – Arizona

- Created a solar financing program for faith based organizations.
- Instrumental in forming the Southern Arizona Solar Standards Board.
  - The first organization in the country dedicated solely to consumer protection around distributed generation.

Policy Program Associate August 2007 – September 2010

Research Institute for Solar Energy at the University of Arizona – Arizona

- Helped build the institute while gaining experience with the technical attributes and challenges of various energy technologies.
- Worked with the Greater Phoenix Economic Council on communicating a program to attract renewable energy manufacturers to Arizona. Published a white paper and policy brief for state legislators. A bill (SB 1403) based on this program was signed into law.
- Created PV Sim, an online financial calculator for prospective residential PV system owners.

Congressional Fellow
US House of Representatives – Washington D.C. January 2009 – May 2009

- Responsibilities included writing weekly memos to the Congress member on energy issues, forming energy related legislation (Solar Schools Act - H.R. 4967), and creating educational presentations on energy.

Education

Masters of Business Administration (MBA) January 2010 – May 2011
Eller College of Management - University of Arizona

Bachelor of Science - Public Policy and Management August 2005 – May 2009
School of Government & Public Policy - University of Arizona
Cumulative GPA: 4.00 - Honors - Summa Cum Laude
Dean's List with Highest Academic Distinction & Senior of the Year Award

Community Involvement

- Appointed to the Arizona Governor's Solar Task Force, 2013
- Chairman - Southern Arizona Regional Solar Partnership at the Pima Association of Governments, 2011
- Founding Chairman - University of Arizona Green Fund, 2010 to 2011
- Member of UA President's Campus Sustainability Advisory Board, 2008 to 2011
- Big Brother for a child in special needs program - Tucson Big Brothers Big Sisters, 2006 to 2008

Awards & Honors

- Arizona Daily Star's "40 Under 40" winner for leadership, community impact, and professional accomplishment
- University of Arizona Honors College Young Alumni Award Winner, 2011
- Outstanding Professional Staff Member – University of Arizona, 2010
- Arizona Foundation Outstanding Senior Award for the Eller College of Management, 2009
- Honors College Pillars of Excellence Award, March 2009
- Congressional Recognition Award, May 2008

Professional Accomplishments

- Graduate of NARUC Rate Design School, 2014
- Microsoft Excel certified Specialist, 2006
- A+ certified, 2005

Exhibit 2:

Market Potential Study

Sustainable Energy Advantage, LLC

Estimating Technical and Economic Potential for Small-Scale Solar PV in New Hampshire

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Prepared for Strategen Consulting, on behalf of the New Hampshire Office of Consumer Advocate (OCA)

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Overview & Summary of Results

- At the direction of new paragraph XVI of R.S.A. 362-A:9, the New Hampshire Public Utilities Commission (NH PUC) opened Docket No. DE 16-576 to "develop new alternative net metering tariffs, which may include other regulatory mechanisms and tariffs for customer-generators, and determine whether and to what extent such tariffs should be limited in their availability within each electric distribution utility's service territory."
- After a competitive procurement process, the New Hampshire Office of Consumer Advocate (OCA) selected Strategen Consulting (with Sustainable Energy Advantage, LLC as a subcontractor) to provide expert assistance in the docket.
- OCA, through Strategen, specifically requested that SEA analyze the technical and economic potential of "small-scale" solar PV (defined as 100 kW_{DC} or less) in the state of New Hampshire, within the service territories of Public Service Co. of New Hampshire ("Eversource"), Unitil Energy Systems ("Unitil") and Granite State Electric Co. ("Liberty").
- In terms of technical potential (which accounts only for the maximum size of the market regardless of economics), SEA finds that based on a 76% historical growth rate in the various <100 kW_{DC} market subsectors, there is 781 MW_{DC} in incremental small-scale technical potential available through 2022.
- SEA analyzed OCA's proposed policy framework for 100 kW_{DC} or less solar PV and in terms of economic potential (which accounts for capacity that would economically deploy under the policy framework proposed by OCA), SEA finds that 653 MW_{DC} (representing 84% of the incremental technical potential) could notionally deploy by 2022 (without accounting for potential policy implementation lag, financial, technical, labor and other variables, which are not accounted for in this analysis).

Technical and Economic Potential Methodology

Part 1: OCA Development of Generic Small-Scale Market "Supply Blocks"

- Developing a solar PV supply curve for a supply/demand analysis requires developing a series of differentiated categories of supply (referred to hereafter as "supply blocks").
- Based on data provided by the NH PUC Sustainable Energy Division (SED), OCA determined that supply blocks in the NH "small-scale" market could be differentiated by:
  - **System Size and Market Sector** Using the SED data and the Renewable Energy Fund (REF) incentive categories, OCA determined that the small-scale market could be subdivided into residential and small commercial segments. OCA provided SEA with information suggesting the average size of residential and small commercial systems installed in 2016 were **7 kW_{DC} and 32 kW_{DC} respectively**.
  - **Approach to Claiming Federal ITC** If solar PV system owners (as most or all do) choose to apply the federal Investment Tax Credit (ITC) to the cost of their system, they tend to use either 1) the cost of their system as the basis to take the credit (known as the "cost basis" approach), or 2) the system's "fair market value" (FMV)). Generally, systems in the small-scale sector using the FMV approach are third-party owned, and need less state incentive to reach their financial hurdle rates due to their ability to claim higher ITC values.
  - **Financial Hurdle Rates within Residential Direct Ownership Subsector** The financial "hurdle rates" that certain customers directly purchasing their systems may accept as a metric of financial success also often differ. Certain direct ownership customers tend not to prioritize more rapid investment paybacks (and thus, as a result of lower financing costs, have a lower cost of ownership).
- The generic supply blocks developed by OCA and submitted to SEA were as follows:

Block	"Small Scale" Market Sector/Modeled Size (kW_{DC})	Treatment of ITC Value	Hurdle Rates
1	Residential (7 kW_{DC})	Cost Basis	Base(using SEA financial assumptions)
2	Residential (7 kW_{DC})	FMV Basis	Base (using SEA financial assumptions)
3	Residential (7 kW_{DC})	Cost Basis	Low
4	Small Commercial (32 kW_{DC})	Cost Basis	Base (using SEA financial assumptions)
5	Small Commercial (32 kW_{DC})	FMV Basis	Base (using SEA financial assumptions)

Part 2: OCA Cost Analysis Results by Supply Block

- The next key step in developing supply blocks for the small-scale market is to estimate the total levelized revenue requirement value (in cents/kWh) of each supply block during the expected duration of the proposed program (2017-2022).
- A system's revenue requirement is its total levelized cost (including installed cost, ongoing operations and maintenance, interconnection, financing, project management, and other relevant categories of cost). It represents the total value that all possible market revenues (e.g., behind-the-meter bill savings from net metering alternatives etc.) as well as all potential incentive revenues (from federal, state, local and utility sources) would yield.
- OCA provided SEA with the following statewide revenue requirement estimates (in cents/kWh) for each generic supply block, which SEA split between Eversource, Liberty and Unitil.

Block Identifiers	2017	2018	2019	2020	2021	2022
7 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC, ¢/kWh)	17.55	16.55	15.55	16.15	15.95	14.85
7 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC, ¢/kWh)	15.45	14.65	13.75	14.25	14.15	13.15
7 kW_{DC}, Low Financing Assumptions (Cost Basis for ITC, ¢/kWh)	16.90	15.90	15.00	15.60	15.40	14.30
32 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC, ¢/kWh)	16.25	15.05	14.05	14.35	13.95	12.85
32 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC, ¢/kWh)	14.35	13.35	12.45	12.75	12.45	11.35

Part 3: SEA Technical/Economic Potential Approach (1)

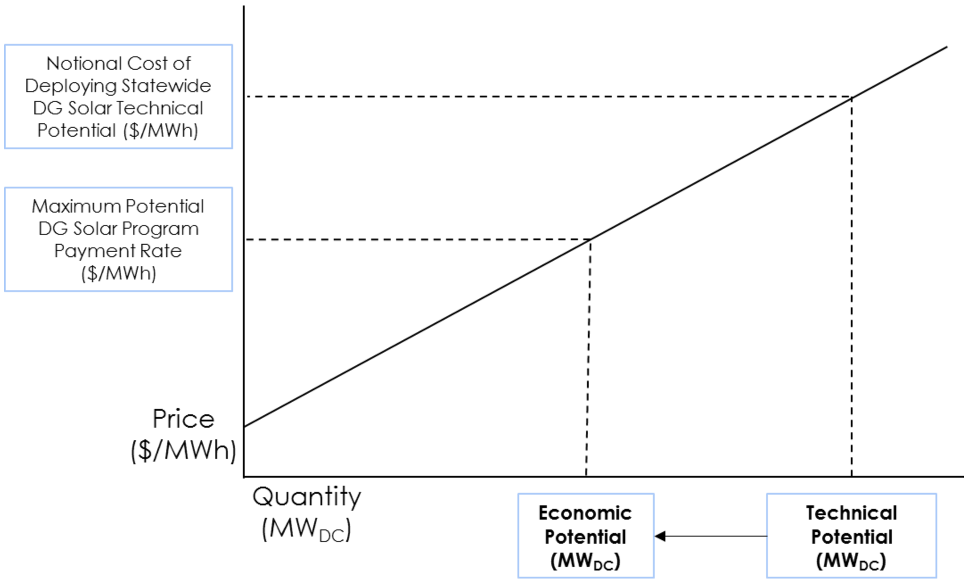


Illustration of SEA Approach to Economic Modeling of NH Small-Scale PV Market Sector

- The three components of an appropriate deployment analysis are to develop 1) a "technical potential" (which sets the maximum market size for each supply block and 2) an "economic potential" (the maximum amount of capacity that would deploy at the proposed compensation rates).**
- These values make it possible to <u>determine how much capacity would deploy at different proposed compensation rates,</u> within the bounds of an assumed maximum size of the small-scale market (as shown above).

***We note that the total economic potential can (and often is) limited to an "actual" deployment figure by interconnection constraints, a lack of available financing, capital or labor, competition with other energy sources, policy targets, regulatory limits and other implementation issues. See Brown, et al. "Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results." Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-64503, August 2016. Available at: http://www.nrel.gov/docs/fy15osti/64503.pdf*

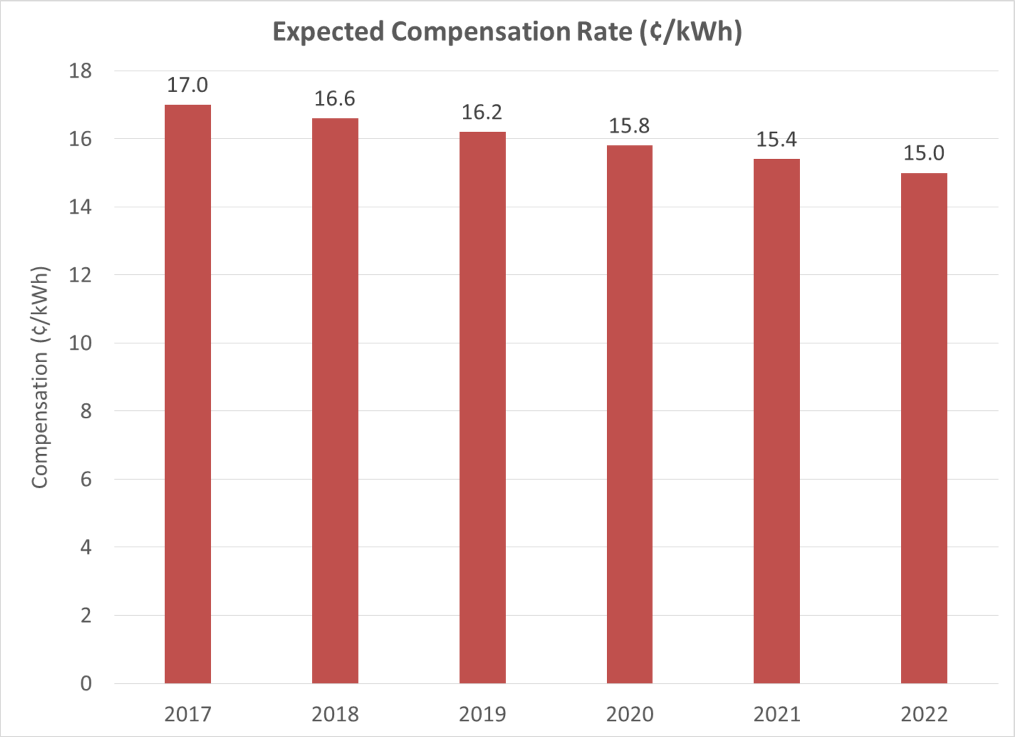
Part 3: SEA Technical/Economic Potential Approach (2)

- According to a recent analysis** undertaken by the National Renewable Energy Laboratory, New Hampshire has approximately 3,200 MW of rooftop PV technical potential (given the roof area of its existing building stock). However, even if all such capacity were economic, SEA assumes that there are practical limits on the total market-wide deployment of solar PV in each year.
  - For this purpose, SEA assumed that the maximum annual capacity the industry could install in a given year through 2022 would not exceed the 76% compound annual growth rate (CAGR) SEA observed in SED data for both the residential (0-12.5 kW_{DC}) and small commercial (<100 kW_{DC}) market segments since 2009 and 2011, respectively (the initial year of each program).
- Based on the above, SEA estimates an incremental (post-2016) technical potential of **781 MW_{DC}** by 2022. The total potential is broken out by utility and generic supply block in the table below.

Utility	Generic Supply Block Type	Incremental Technical Potential (MW_{DC})					
		2017	**2018**	**2019**	**2020**	**2021**	**2022**
Eversource	7 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC, ¢/kWh)	2.5	5.1	9.0	15.8	27.8	48.9
	7 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC, ¢/kWh)	5.7	11.9	20.9	36.8	64.8	114.1
	7 kW_{DC}, Low Financing Assumptions (Cost Basis for ITC, ¢/kWh)	1.7	3.5	6.2	10.9	19.1	33.7
	32 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC, ¢/kWh)	2.6	5.5	9.7	17.0	29.9	52.7
	32 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC, ¢/kWh)	1.2	2.5	4.4	7.8	13.7	24.1
Unitil	7 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC, ¢/kWh)	0.4	0.8	1.5	2.6	4.6	8.1
	7 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC, ¢/kWh)	1.0	2.0	3.5	6.1	10.8	19.0
	7 kW_{DC}, Low Financing Assumptions (Cost Basis for ITC, ¢/kWh)	0.3	0.6	1.0	1.8	3.2	5.6
	32 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC, ¢/kWh)	0.4	0.9	1.6	2.8	5.0	8.8
	32 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC, ¢/kWh)	0.2	0.4	0.7	1.3	2.3	4.0
Liberty	7 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC, ¢/kWh)	0.3	0.6	1.0	1.8	3.2	5.6
	7 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC, ¢/kWh)	0.7	1.4	2.4	4.3	7.5	13.2
	7 kW_{DC}, Low Financing Assumptions (Cost Basis for ITC, ¢/kWh)	0.2	0.4	0.7	1.3	2.2	3.9
	32 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC, ¢/kWh)	0.3	0.6	1.1	2.0	3.5	6.1
	32 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC, ¢/kWh)	0.1	0.3	0.5	0.9	1.6	2.8

***See Gagnon, et al. "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment. Golden, CO: National Renewable Energy Laboratory". NREL/TP-6A20-65298, January 2016. Available at: http://www.nrel.gov/docs/fy16osti/65298.pdf*

Part 3: SEA Technical/Economic Potential Approach (3)



Maximum Small-Scale DG Compensation Rates by Year

- **Maximum Payment Rates/kWh** To pare down the technical potential to values that represent realistic market deployment, it is necessary to introduce the details of the proposed policy. Under OCA's proposed policy, the total expected compensation rate (i.e. bill savings) a small-scale system would experience would start at 17 cents/kWh for all generation on a 20-year fixed basis, declining by 0.4 cents/kWh per year until 2022, when the compensation level would be 15 cents/kWh on the same 20-year fixed basis. These values can be seen above.

Results of Economic Potential Analysis

Results of Economic Potential Analysis (1)

- Based on SEA's estimates of the total market size in the Technical Potential analysis, the forecasted cost of solar PV systems and the expected payment rates for small-scale solar PV, SEA estimates that under the proposed policy framework, **653 MW_{DC}** in new capacity (84% of the total Technical Potential) would be economical. The table below compares statewide economic and technical potential estimates by year.

Year	2017	2018	2019	2020	2021	2022	Total
Eversource Technical Potential (MW_{DC})	13.7	28.5	50.1	88.3	155.3	273.4	609.3
Eversource Economic Potential (MW_{DC})	**10.1**	**26.0**	**45.7**	**64.7**	**113.9**	**249.3**	**509.7**
Unitil Technical Potential (MW_{DC})	2.3	4.7	8.4	14.7	25.9	45.6	101.6
Unitil Economic Potential (MW_{DC})	**1.7**	**4.3**	**7.6**	**10.8**	**19.0**	**41.6**	**84.9**
Liberty Technical Potential (MW_{DC})	1.6	3.3	5.8	10.2	17.9	31.5	70.3
Liberty Economic Potential (MW_{DC})	**1.2**	**3.0**	**5.3**	**7.5**	**13.1**	**28.8**	**58.8**
Total Economic Potential (MW_{DC})	***12.9***	***33.3***	***58.6***	***83***	***146***	***319.6***	***653.4***
Total Technical Potential (MW_{DC})	***17.6***	***36.5***	***64.3***	***113.1***	***199.1***	***350.5***	***781.2***
Annual Economic Potential % of Technical Potential	***73%***	***91%***	***91%***	***73%***	***73%***	***91%***	***84%***

- Overall, the OCA-proposed payment rates would incentivize development in all market segments, regardless of utility service territory. In general, the lower-cost small commercial systems and the "fair market value" systems that need less ratepayer incentive to deploy have a moderate cost advantage relative to systems that use the cost basis for claiming the ITC, and residential systems in general. However, residential systems that benefit from having lower financial hurdle rates (and thus a lower cost of capital) are more likely to deploy and flourish throughout the life of the program. The overall economic deployment potential by block can be seen in the table on the following page.

Results of Economic Potential Analysis (2)

Economic Potential/Deployment by Supply Block (MW_{DC})							
Utility	Supply Block Name	2017	2018	2019	2020	2021	2022
Eversource	32 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC)	2.64	5.49	9.66	17.00	29.92	52.66
Eversource	32 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC)	1.69	3.51	6.18	10.87	19.13	33.67
Eversource	7 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC)	5.73	11.89	20.93	36.84	64.83	114.10
Eversource	7 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC)	-	5.09	8.97	-	-	48.88
Eversource	7 kW_{DC}, Low Financing Assumptions (Cost Basis for ITC)	1.21	2.51	4.42	7.77	13.68	24.07
Unitil	32 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC)	0.44	0.91	1.61	2.83	4.99	8.78
Unitil	32 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC)	0.28	0.58	1.03	1.81	3.19	5.61
Unitil	7 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC)	0.95	1.98	3.49	6.14	10.81	19.02
Unitil	7 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC)	-	0.85	1.49	-	-	8.15
Unitil	7 kW_{DC}, Low Financing Assumptions (Cost Basis for ITC)	0.20	0.42	0.74	1.30	2.28	4.01
Liberty	32 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC)	0.31	0.63	1.11	1.96	3.45	6.08
Liberty	32 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC)	0.20	0.40	0.71	1.25	2.21	3.88
Liberty	7 kW_{DC}, Base Financing Assumptions (FMV Basis for ITC)	0.66	1.37	2.41	4.25	7.48	13.17
Liberty	7 kW_{DC}, Base Financing Assumptions (Cost Basis for ITC)	-	0.59	1.03	-	-	5.64
Liberty	7 kW_{DC}, Low Financing Assumptions (Cost Basis for ITC)	0.14	0.29	0.51	0.90	1.58	2.78