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

# Joint Settlement Proposal from the Energy Future Coalition

*Executive Summary*

There is growing recognition among many stakeholders that the electric grid is evolving, and as the penetration of solar and other distributed energy resources ("DER") increases, there needs to be better and more optimized alignment of the locational and temporal value solar and other distributed resources provide to the grid. The Energy Future Coalition ("the Coalition"), composed of Acadia Center, The Alliance for Solar Choice, Borrego Solar, Conservation Law Foundation, Energy Freedom Coalition of America, LLC, New Hampshire Sustainable Energy Association, ReVision Energy, Granite State Hydropower Association, Sunraise Investments LLC, Solar Endeavors, LLC, and Revolution Energy, LLC, has developed this Joint Settlement Proposal ("Proposal") that provides the state with a path for aligning compensation of distributed energy resources (DER) with the value they provide to the grid.

Significant momentum has been gained during this proceeding but there is still a paucity of data regarding the value that DER provide to New Hampshire ratepayers. Moreover, there is scant experience in New Hampshire with alternative tariffs outlined in the pre-filed testimony of various parties, nor do utilities or DER providers have systems in place to administer the proposals. This Proposal seeks a phased in approach with gradual compensation reductions, enhanced data collection and pilot studies that enables a transition to a technology agnostic program with smarter pricing signals. It allows utilities timely recovery of costs associated with data collection, billing and metering system upgrades, and pilot programs.

| Topic | Small Projects (< 100 kW) | Large Projects (>100 kW) |
|---|---|---|
| Start Date | The net metering cap is eliminated as of September 1, 2017.<br>New tariff will impact only those customer generators placed in the interconnection queue beginning on September 1, 2017<br>If utilities are unable to bill or meter new customer generators by September 1, 2017, those customers will continue to take service under the current program design until the utility billing systems are capable of accommodating the new program design. Utilities should provide 30 days' notice prior transitioning customers to the new program. | Same |

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| Application Fee | No change. Utilities may file for an application fee based on demonstrated costs (Per DE 15-271) | Same |
| Customer Charge for Eligible Customer Generators | No change at this time, however in the future Utilities may file for a supplemental charge only if total customer-related costs for DER customers are higher than for non-DER customers in the same rate class. The supplemental charges would cover demonstrated incremental customer-related costs (i.e., for metering, billing, and service drop) that are specific to DER customers, and the costs should be tracked in separate utility accounts. | Same |
| Rate Design (for imported kW & kWh) | No change (use prevailing rates; as may be amended from time to time). With the exception of a supplemental customer charge to collect incremental, customer-related NEM costs, a net metering customer should have access to the same rates that would be available if the customer was not a customer-generator and should not be subject to any separately enumerated charges | Same |
| Lost Revenue Recovery | PUC approval of lost revenue recovery | Same |
| Stranded Cost charge<br>System Benefit charge<br>ECT<br>Storm Recovery Adjustment | Customer generators are billed on imported kWh and do not receive credit for exported kWh | Same |
| Commodity billing component for exported kWh | Exports credited at the Retail Supply Rate | Exports credited at retail supply rate.<br><br>Customer generators with on-site annual volumetric load must equate to 20% of the DER production, otherwise they must register as a group host<br><br>Customer generators currently registered as group hosts may switch to new tariff if they meet the 20% on site load requirement |

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| Distribution billing component for exported kwh | "Phase 1" Projects placed in the queue on or after:<br>- September 1, 2017: 75% of the volumetric distribution charge.<br>- January 1, 2019: 50% of the volumetric distribution charge.<br>.<br>"Phase 2" Projects placed in the queue on or after:<br>- January 1, 2021: Distribution export values tied to Commission-sponsored independent Value of DER study. | Projects placed into the queue on or after January 1, 2021: Distribution export values tied to Commission-sponsored independent Value of DER study. |
| Transmission billing component for exported kwh | 100% of volumetric Transmission charge of rate class | No change to standard rate; opt-in program to allow RNS and LNS Transmission credit, based on actual avoided marginal costs. In other words, a credit for the reduced distribution load share and resulting variable transmission charges from what they would have been had the customer not reduced their demand. |
| RECs | Customer generator owns RECs. No utility obligation to buy.<br>Utilities agree to work with parties on solicitation for a 3rd party administrator / aggregator.<br>Utilities can facilitate customer education on topic and promote program.<br>Utilities may aggregate or purchase RECs from customer generators for a fixed fee. | Same |
| Metering and Netting | Customer generators impacted by the new tariff: implement two-channel metering in order to apply non-bypassable charges to metered imported energy.<br>All other volumetric based charges for Phase 1 customers will be netted monthly in kWh prior to applying monetary charges. Phase 2 customer generators placed in the queue on or after January 1, 2021 would be subject to monetary billing for volumetric charges and would be credited for exports at the Value of DER. | No change from current rules |
| Credits ($ or KWH) | Transition on September 1, 2017 from kWh crediting to on-bill monetary credit at the applicable rates.<br>Customer can convert bill credit to cash on move out or once per year (each April, provided credit > $100) | Customer can convert bill credit to cash on move out or once per year (each April, provided credit > $100) |
| Banking | No need to bank kWh, roll over monetary credit | Same |

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| Grandfathering | All customers placed in the queue before January 1, 2021 will be grandfathered until December 31, 2040.<br>All projects placed in the queue on or after January 1, 2021 will be grandfathered for 20 years.<br>Customers can move to a future alternative program or rate plan on request. | Same |
| Phase 1 pilots - creation to be guided by a task force and filed for approval with the Commission | Parties agree that following the pilots a proceeding will be opened with the commission focused on evaluating and implementing the results<br><br>All potential Pilots will have a statistically valid number of participants<br><br>1) OCA's "low to moderate income" adder pilot (min. of 100 customers per utility)<br>2) Residential voluntary TOU pilot<br>3) Residential voluntary "Smart Home Energy Rate" pilot that tests other rate designs such as real-time pricing, critical peak pricing, demand charges or other structures that enable customers to adopt a variety of technologies to manage their electricity consumption.<br>4) Non-wires alternative pilot | Eligible to participate in non-residential specific pilots. |
| Data Collection & Studies | 1) DER Location Valuation study<br>2) Evaluation of avoided distribution capacity costs<br>3) Further review of appropriate compensation for avoided RNS cost allocation<br>4) Marginal Cost of Service study by Eversource to be completed prior to V-DER study completion<br>5) Timely cost recovery of all study efforts<br>Stakeholder working groups should be created to develop data collection and study plans for Commission approval. | Same |

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| Transition to Phase 2 | Within 60 days of the Commission order, a stakeholder working group will be created to develop specifics for the pilots and studies that will ultimately be approved by the Commission. The studies should seek to begin enrolling customers in 2018 and report back to the Commission every 180 days about the pilot's progress.<br>A stakeholder working group should also define the parameters and data requirements of an independent, Commission-sponsored Value of DER study. The study should be conducted by January 1, 2020 and will be used inform the distribution export rate that goes into effect January 1, 2021.<br>The utilities should also develop optional Time-of-Use and "Smart Energy Home" rates that DER customers can sign up for beginning January 1, 2021.<br>The V-DER study should be updated every three years in order to account for changes in values and more precise data and analysis. | Same |
| Metering | No requirement for Revenue-grade Production Meters owned by utilities or otherwise | Same, optional in order to receive T-credit |

**STATE OF NEW HAMPSHIRE**

**BEFORE THE PUBLIC UTILITIES COMMISSION**

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

ENERGY FUTURE COALITION SUPPLEMENTAL SETTLEMENT TESTIMONY OF

R. THOMAS BEACH

AND

PATRICK BEAN

AND

KATE BASHFORD EPSEN

AND

FORTUNATE MUELLER

AND

NATHAN PHELPS

AND

KARL R. RABAGO

## I. INTRODUCTION

**Q. Mr. Beach, please state your name, position and business address.**

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

**Q. Mr. Bean, please state your name, position and business address.**

A. My name is Patrick Bean. I am a Deputy Director of Policy and Electricity Markets at SolarCity, a wholly owned subsidiary of Tesla, Inc. My business address is 601 13th Street NW, Suite 900, Washington, DC 20005.

**Q. Ms. Epsen, please state your name, position and business address.**

A. My name is Kate Bashford Epsen and I am the Executive Director of the New Hampshire Sustainable Energy Association ("NHSEA"). NHSEA's business address is 54 Portsmouth Street, Concord, NH 03301.

**Q. Mr. Mueller, please state your name, position and business address.**

A. My name is Fortunat Mueller. I am co-founder and managing partner of ReVision Energy. My business address is 142 Presumpscot St, Portland, ME 04103.

**Q. Mr. Phelps, please state your name, position and business address.**

A. My name is Nathan Phelps. I serve as the Program Manager of Distributed Generation ("DG") Regulatory Policy for Vote Solar. My business address is 745 Atlantic Avenue, 7th floor, Boston, Massachusetts 02111.

**Q. Mr. Rábago, please state your name, position and business address.**

A. My name is Karl R. Rábago. I am the Executive Director of the Pace Energy and Climate Center at the Pace University School of Law. My business address is 78 North Broadway, White Plains, New York.

**Q. On whose behalf are you filing this settlement testimony?**

A. We are appearing on behalf of the Energy Future Coalition ("the Coalition") which is comprised of Acadia Center ("Acadia"), the Alliance for Solar Choice ("TASC"), Borrego Solar, the Conservation

Law Foundation ("CLF"), the Energy Freedom Coalition of America, LLC ("EFCA"), the New Hampshire Sustainable Energy Association ("NHSEA"), ReVision Energy ("ReVision"), Granite State Hydropower Association, Sunraise Investments LLC, Solar Endeavors, LLC, and Revolution Energy, LLC.

**Q. What is the Energy Future Coalition?**

A. The Coalition is composed of parties participating in the DE 16-576 proceeding and that share common positions in regard to the future of distributed energy resources ("DER") and the electricity system in New Hampshire. In particular, the parties share an interest in creating a comprehensive roadmap for New Hampshire's Public Utility Commission ("PUC"), utilities, DER providers and other stakeholders that moves the State from Net Energy Metering ("NEM") to a value-based compensation system created through a transparent and data driven process. The parties entered a Joint Settlement as the Coalition in order to develop the roadmap, identify system-wide data gaps and collection of necessary information, immediately begin the transition to a value based program that sends stronger and more precise price signals, and ultimately leverage DER to help reduce the cost of electricity for all New Hampshire ratepayers.

**Q. What is the purpose of your testimony?**

A. We will outline the comprehensive roadmap and measures required to begin the transition to a smarter energy future. We describe the rationale behind the proposal, how the compromise is in the public's interest, and how the proposal meets the statutory requirements of House Bill 1116 ("HB 1116").

**Q. Do you incorporate by reference the testimony that you previously filed in this docket?**

A. Yes, we incorporate by reference the testimony that we have previously filed in this docket.[1]

**Q. Please summarize the requirements of HB 1116.**

A. In May 2016, the New Hampshire General Court and Governor enacted a bill that increased the cap on net metering projects from 50 megawatts to 100 megawatts, and also required that the PUC initiate a proceeding to develop alternative net energy metering tariffs. The General Court's stated purpose of

[1] Testimony and Rebuttal Testimony of R. Thomas Beach, DE 16-576, October 24, 2016 and December 21, 2016; Testimony and Rebuttal Testimony of Patrick Bean, DE 16-576, October 25, 2016 and December 21, 2016; Testimony of Kate Epsen, Nathan Phelps and James Bride, DE 16-576, October 24, 2016; Rebuttal Testimony of Karl R. Rábago, Nathan Phelps and James Bride, DE 16-576, December 21, 2016.

the bill was stated as follows: "to promote energy independence, and local renewable energy resources, the general court finds that it is in the public interest to continue to provide reasonable opportunities for electric customers to invest in and interconnect customer-generators facilities and receive fair compensation for such locally produced power while ensuring costs and benefits are fairly and transparently allocated among all customers. The general court continues to promote a balanced energy policy that supports economic growth and promotes energy diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits, a fair allocation of cost and benefits, and a modern and flexible electric grid that provides benefits for all ratepayers."

**Q. Does the Coalition's proposal meet the objectives of HB 1116?**

A. Yes. The proposal reflects a consideration of HB 1116's many objectives. First and foremost, it considers the costs and benefits of customer-generator facilities, an avoidance of unjust and unreasonable cost shifting, and its rate effects on all customers. The Coalition's proposal also seeks to develop pilot programs, data collection, and an independent value of DER ("VDER") study sponsored by the PUC in order to ensure "costs and benefits are transparently allocated among all customers." The proposal promotes energy independence, a diversified and distributed energy mix, reliability, and local renewable energy sources. It seeks to allow reasonable opportunities for customer-generators and others to invest in and interconnect with local renewable energy projects, for which customer-generators will receive fair compensation based on fair and transparently allocated costs and benefits. Finally, the proposal charts a path from the present to a modern, flexible grid that benefits all ratepayers and provides regulatory predictability for the PUC, utilities, DER providers and other stakeholders.

## II. Summary of the Coalition Proposal

Q. **Please provide an overview of the Coalition settlement proposal**.

A. At the core of the Coalition's proposal is a gradual transition from net energy metering to value-based tariffs that includes step downs in the distribution credit for net exports until an independent, PUC sponsored study of VDER is conducted and will serve as the basis for valuing and crediting exports from DER in the future. The Coalition refers to the transition period as Phase 1, while Phase 2 refers to the program in which a customer's exports are credited at the VDER and when other optional rates, such as time-of-use ("TOU") and or "Smart Home Rates" are made available to all ratepayers.

The Coalition proposal also seeks to begin the collection of non-bypassable charges from customer generators based on their delivered loads, the move to monetary crediting from volumetric (kilowatt-hours or "kWh") crediting, and the initiation of data collection and pilot programs that will inform the ultimate design of the Phase 2 program.

Exhibit 1 appended to our testimony outlines the proposal by topic and applicability to small and large projects. Much of our testimony relates to projects that are 100 kilowatts (kW) in capacity or less.

**Q. Are you making any changes to the program applicable to large projects (greater than 100 kW)?**

A. The proposal makes minor changes to the program for larger projects in the near term. These include clarifying commodity billing for group hosts, and creating an optional program to receive a transmission credit for demonstrated load reduction during the hour of coincident peak.

**Q**. **Please describe the design of the Coalition's Phase 1 program**.

A. The Coalition's proposes that all projects placed into the interconnection queue beginning on September 1, 2017 will be subject to the Phase 1 program design. Customers would be billed non-bypassable charges on all imported kWh and would not receive credit for non-bypassable charges for any exported kWh, thus ensuring that all customers pay non-bypassable charges on their delivered volumes from the utility. The non-bypassable charges includes the Stranded Cost Charge; System Benefit Charge; Storm Recovery Adjustment; Electricity Consumption Tax. In order to charge for non-bypassable charges, new projects placed in the interconnection cue beginning September 1, 2017 would require two-channel meters that measure imports from the utility and exports to the utility.

For other billing components, customers with DER would pay the full generation, transmission and distribution rates for all net imports during the course of a month. For net monthly exports, the customers would be credited at the retail supply rate for generation, the full transmission charge for their rate class, and a portion of the distribution rate component as further described below.

For the distribution component of the credit for exported power, projects placed in the interconnection queue beginning on September 1, 2017 would be credited at 75% of the volumetric distribution charge for their rate class for monthly net exports. Projects placed in the interconnection queue beginning on January 1, 2019 would be credited at 50% of the prevailing volumetric distribution rate.

The Coalition proposes that projects placed in the interconnection queue beginning on January 1, 2021 be subject to the Phase 2 requirements.

**Q. Why do you believe that your crediting proposal is fair to all stakeholders, including non-participating ratepayers, and does not result in undue cost shifts?**

A. The Coalition continues to stand by its testimony in this case, which, as required by HB 1116, presented a comprehensive benefit-cost methodology for valuing customer-sited DG resources. This methodology examined the benefits and costs from the multiple perspectives of the key stakeholders and analyzed a comprehensive list of benefits and costs using a long-term, life-cycle analysis. These analyses concluded that solar DG is a cost-effective resource for all of the utilities, as the benefits equal or exceed the costs in the Total Resource Cost and Societal tests. The benefits and costs for non-participating ratepayers are also reasonably balanced, as shown by the Rate Impact Measure (RIM) test results. The RIM results indicate that there is no significant cost shift to non-participating ratepayers. In fact, in the long-run these other customers will also realize net benefits, both direct and societal, from DG development under net metering. Given these results, the Coalition's compromise proposal with lower distribution credits than assumed in our benefit-cost analyses, plus monetary crediting and possible additional cost-based fees on DG customers, will provide additional benefits to non-participating ratepayers flowing from customer generators.

**Q. Why are you proposing monthly netting for other billing components but not for non-bypassable charges?**

A. Currently, net metering customers receive the non-bypassable charge in net metering credit calculations. The Coalition recognizes that evidence was not provided in this proceeding that demonstrates that DG provides benefits to all distribution company customers relative to the non-bypassable charge components. Accordingly, the Coalition believes that VDER for these components is zero for the purposes of this proceeding. As a result, we propose that Phase 1 customers be subject to non-bypassable charges on an instantaneous netting basis, while netting on a monthly basis for all other charges.

Unlike the non-bypassable charge elements, DG does provide benefits to all distribution company customers, and thus at least a portion of the distribution rate should be included in the export credit. As such, the current net metering framework of monthly netting is maintained until such time as the VDER dictates otherwise.

**Q. Do you have concerns about instantaneous netting?**

A. Yes. Instantaneous netting does not send good price signals and can be complicated for customers to understand. First, instantaneous netting results in a distorted price signal to customers and encourages behavior that is suboptimal for the electric system. Instantaneous netting only makes sense when an entity wants to charge a customer a different price for using electricity from the utility than for exporting electricity to the utility. If a customer is charged more for electricity deliveries from the utility than they receive for electricity exports, then the customer is financially motivated to use as much electricity on-site regardless of the impacts on the electric system. For instance, under instantaneous netting a customer with a solar system would be financially motivated to program their dishwasher to run during hours when their solar system would produce electricity, rather than program their dishwasher to run in the middle of the night in order for optimal usage of the electricity system. Although flat monthly rates do not send very good price signals in general, flat monthly rates combined with monthly netting motivate customers to maximize production and minimize consumption through energy conservation, energy efficiency, and DER implementation as a whole. The Coalition is strongly supportive of rate structures that will further send price signals to customers to maximize production during periods of electric system constraints and minimize consumption during periods of electric system constraints, such as TOU rates with netting during each time period.

Furthermore customers currently only receive a limited amount of data from utilities about their consumption. Most often this is the customer’s monthly consumption, and sometimes hourly consumption. Instantaneous customer demand data is not currently available – and likely will not be available in the near future[2] -- which therefore makes it difficult for DER providers to confidently forecast potential energy savings to prospective customers, and for customers to understand the value of investing in DER. Experience in other states has shown that there can be a significant difference in exported volumes depending on whether netting occurs on a monthly, hourly, or instantaneous basis. These differences are also customer-specific, depending on the details of the customer’s load profile and solar system. Data to assess and understand these differences in the New Hampshire market do not exist at present. Accordingly, the lack of real-time information to customers combined with instantaneous netting creates, at best, and obfuscated price signal to customers to operate in a manner that is beneficial to the electric system.

[2] See Eversource’s response to TASC 3-11 and Unitil’s response to TASC 3-7.

Secondly, customers understand monthly netting, and they may not respond well to the idea of instantaneous netting. Currently, many customers – especially residential customers – are sheltered from price fluctuations in electricity markets. While we are strongly supportive of sending better price signals to customers in order to optimize the use of the electricity system, instantaneous netting layered on top of other price signals may confuse customers and, as discussed above, result in suboptimal customer behavior. Monthly netting is easy to understand for customers and preserves the current motivation to use less electricity through conservation and energy efficiency, and therefore advances NH state policy.

**Q. Please describe the Coalition's monetary crediting proposal.**

A. The current net energy metering program for customer-generators credits customers on a volumetric (kWh) basis. For example, if a customer exports energy in the summer months such that they have a balance of 500 kWh credits at the end of September, those kWhs can be credited towards the customer's consumption in the winter months when their DERs are producing less. With monetary crediting, each excess kWh is assigned a monetary value. In the example above, the summer credits would have a value of 12 cents/kWh, thereby equating to a credit of $60 that the customer can apply to their winter bills. If electricity prices are the same in every month, then kWh crediting and monetary crediting have the same value. However, electricity prices in New Hampshire often exhibit seasonal differences due to underlying generation supply costs. Therefore, moving to monetary crediting is a compromise by the Coalition that would reduce the value of DER for the customer due to the seasonal electricity price and DER production differentials between summer and winter months. Moving to monetary crediting also supports the transition to greater dependence on time-dependent rates. States such as Arizona and California that have large solar markets and widespread use of TOU rates employ monetary crediting. The Coalition proposes that all customers placed in the interconnection queue beginning on September 1, 2017 be subject to monetary crediting.

**Q. Have you performed any calculations with regards to the potential impacts of the Coalition proposal?**

A. Yes. We created a bill impact model to demonstrate the impacts of solar systems up to 100 kW. The model compares the bills of customers with solar under the current regime (a.k.a. the status quo) to the bills of customers with solar under the Coalition's Phase 1 proposal. The model evaluates the proposal for the periods of 2014 to the present as a counterfactual in order to capture the changes in rates over time (including changes to default service), rather than use steady-state assumptions for rates.

**Q. What are the results of the modeling?**

A. The modeling shows that on September 1, 2017, an average residential solar customer that consumes 600 kWh a month and has a 6 kW array would see an average monthly increase to their electric bill of between 9.73% and 22.65% compared to the status quo. On January 1, 2019, the increase rises to between 12.34% and 25.39%. Table 1, below, is a summary of the percentage increase from the status quo for all customer classes.

| **Table 1: Bill Impact Summary of the Percentage Difference From Status Quo** | Coalition Proposal Phase 1, 9/1/17 | Coalition Proposal Phase 1, 1/1/19 |
|---|---|---|
| Eversource Residential | 22.65% | 25.39% |
| Liberty Residential | 16.27% | 18.56% |
| Unitil Residential | 9.73% | 12.34% |
| Eversource Small C&I | 1.87% | 1.92% |
| Liberty Small C&I | 3.69% | 3.75% |
| Unitil Small C&I | 1.63% | 1.63% |
| Eversource Medium C&I | 0.12% | 0.12% |
| Liberty Medium C&I | 0.12% | 0.12% |
| Unitil Medium C&I | 0.27% | 0.27% |
| Eversource Large C&I | 0.01% | 0.01% |
| Liberty Large C&I | 0.01% | 0.01% |
| Unitil Large C&I | 0.01% | 0.01% |

Exhibit 2, appended to our testimony, presents the model.

**Q. What are the bill impacts on a monetary basis?**

A. The modeling shows that on September 1, 2017, an average residential solar customer that consumes 600 kWh a month and has a 6 kW array would see an average monthly increase to their electric bill of between $1.63 and $4.38 compared to the status quo. On January 1, 2019, the increase rises to between $2.07 and $4.91. Table 2, below, is a summary of the monetary increase from the status quo for all customer classes.

| **Table 2: Bill Impact Summary of the Average Monetary Monthly Difference From Status Quo** | Coalition Proposal Phase 1, 9/1/17 | Coalition Proposal Phase 1, 1/1/19 |
|---|---:|---:|
| Eversource Residential | $4.38 | $4.91 |
| Liberty Residential | $2.95 | $3.36 |
| Unitil Residential | $1.63 | $2.07 |
| Eversource Small C&I | $2.02 | $2.08 |
| Liberty Small C&I | $2.05 | $2.08 |
| Unitil Small C&I | $2.16 | $2.16 |
| Eversource Medium C&I | $17.38 | $17.38 |
| Liberty Medium C&I | $16.21 | $16.21 |
| Unitil Medium C&I | $29.26 | $29.26 |
| Eversource Large C&I | $9.54 | $9.54 |
| Liberty Large C&I | $10.02 | $10.02 |
| Unitil Large C&I | $11.52 | $11.52 |

**Q. Why are you proposing a September 1, 2017 start date to Phase 1 rather than at the time of the Commission order in this proceeding?**

A. DER systems represent major investments and the timeline from initial contracting through financing to the operation date can take several months or more. If a Commission Order were to be filed in the next few months that includes a dramatic departure from the current NEM program, DER providers could be left scrambling to upgrade systems, retrain sales staff, and educate prospective customers about DER opportunities. Beginning September 1, 2017 gives the companies some time to make changes and adapt to the new program. Potential net metering customers should also be afforded the opportunity to account for policy changes that will impact their potential investment. An abrupt change in policy would harm potential net metering customers that are in the decision-making process and future net metering customers that are in the process of installing DG. Moreover, based on the most recent available utility data, Eversource, Liberty Utilities, and Unitil have 16.3 megawatts ("MW"),[3] 3.65 MW,[4] and 3.2 MW[5] of capacity allocations available, respectively, for small projects up to 100 kW under the existing Net Metering program. Although significant capacity is available under the current program, the Coalition is willing to begin transitioning small projects (below 100

[3] Eversource Net Metering Program Capacity Cap as of February 6, 2017. https://www.eversource.com/Content/nh/about/doing-business-with-us/builders-contractors/interconnections/new-hampshire-net-metering/new-hampshire-net-metering-program-capacity-cap

[4] Liberty Utilities Net Metering Status as of February 17, 2017. https://new-hampshire.libertyutilities.com/uploads/Rates%20and%20Tariffs/Net%20Metering/NetMeteringWeeklyStatusReportFeb17.pdf

[5] Unitil Energy Systems Net Metering Cap Allocation Status as of February 16, 2017. http://unitil.com/energy-for-residents/electric-information/distributed-energy-resources/net-metering

kW) to the new rules in the coming months in order to create a program that is value based and sends customers more precise price signals.

**Q. What if utilities are unable to update their billing and metering systems for Phase 1 customers by September 1, 2017?**

A. If utilities are unable to administer the Phase 1 program by September 1, 2017, customers can be billed under the current program until the utilities' systems are capable of billing Phase 1. Under such a scenario, utilities should provide customers with thirty days' notice of when their billing will convert to the Phase 1 program and reduced crediting value. Customers would not be subject to any retroactive adjustments back to September 1, 2017.

**Q. Does the Coalition's proposal include a separate rate class for customer-generators or DER customers?**

A. No. The Coalition is not proposing to create a separate rate class for DER customers. In accordance to Section I of HB 1116, the Coalition recommends that DER customers take service under "standard tariffs" which "shall be identical, with respect to rates, rate structure, and charges, to the tariff under which a customer-generator would otherwise take default generation supply service from the distribution utility."

**Q. Please describe the design of the Coalition's Phase 2 program.**

A. The Coalition's proposes that DER customers placed in the interconnection queue beginning on January 1, 2021 be credited for their monthly exports at the Value of DER as determined by an independent, Commission sponsored VDER study.

**Q. Why are a gradual transition and a long-term roadmap important in this proceeding?**

A. Providing measured, gradual steps along with a roadmap gives utilities and New Hampshire's DER providers greater certainty in order to plan and adapt their businesses. It also provides greater certainty to customers. A sudden and drastic change from the net energy metering framework can have severe economic consequences for the State, its DER industry and their customers. Such a change occurred in Nevada in late 2015, when rate changes were announced on December 22, 2015 and implemented effective January 1, 2016. Bill savings for typical net metered customer fell by 42%

or more.[6] As a comparison, Eversource's and Unitil's proposals in this case would reduce customer bill savings by 47% - 51%, and 60% - 63%, respectively.[7] In Nevada, the sudden rate change led to a 99% decline in solar applications—down to just 287 solar applications statewide in 2016.[8] A recent report found the state lost 2,687 rooftop solar jobs in 2016,[9] and the Governor of Nevada's Chief Strategy Officer testified that the decision "damaged" Nevada's international reputation.[10]

Subsequently, the Governor of Nevada asked for a "new direction" for the Public Utilities Commission and replaced two of the three Commissioners. The new Commission ruled that the 2015 order was "incongruous with the policy of the State of Nevada…and the public interest."

Articulating the general direction in which New Hampshire intends to move towards such as value based or dynamic pricing programs, gives utilities and DER providers some certainty about how to upgrade their billing systems (along with the required flexibility to accommodate incremental changes rather than complete system overhauls), adapt their business models, make additional investments (such as in metering infrastructure), and retrain their sales teams. It also provides greater certainty and information to prospective DER customers. One of the general court's stated objectives for HB 1116 was to promote "regulatory predictability" and for the Commission to consider "administrative processes required to implement such tariffs and related regulatory mechanisms." The Coalition believes its proposal provides that to utilities, DER providers, customers and other stakeholders.

**Q. Are there examples of programs in other States that are similar to the Coalition's phased-in proposal?**

A. Yes. In New York, electricity distribution utilities and DER providers came to agreement in 2016 that new on-site (i.e., not virtual or remote net metering systems) DER installations should continue under the existing net energy metering program. The agreement proposed that new on-site DER projects

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[6] Direct testimony of R. Thomas Beach, Application of Nevada Power Company d/b// NV Energy and Application of Sierra Pacific Power Company d/b/a NV Energy for Approval of Cost of Service Study and Net Metering Tariffs. Dockets Nos. 15-07041 and 15-07042. February 1, 2016. Pg. 15.

[7] Rebuttal Testimony of R. Thomas Beach, Docket No. DE 16-576, December 21, 2016, at pg. 44.

[8] Rothberg, D. February 20, 2017. "Energy updates: Coal is out, NV Energy asks to boost rooftop solar incentives." The Las Vegas Sun. Available from https://lasvegassun.com/news/2017/feb/20/energy-updates-no-gas-plant-for-nv-energy-the-sola/

[9] Whaley, S. February 7, 2017. "Nevada loses 400 solar jobs, but still ranks 4th nationally." The Review-Journal. Available from http://www.reviewjournal.com/business/energy/nevada-loses-400-solar-jobs-still-ranks-4th-nationally

[10] Whaley, S. March 22, 2016. "Official: Fallout from PUC ruling tarnished Nevada's clean energy image." The Review-Journal. Available from http://www.reviewjournal.com/business/energy/official-fallout-puc-ruling-tarnished-nevada-s-clean-energy-image

beginning in January 1, 2020 would transition to a value-based program.[11] On March 9, 2017, the New York Public Service Commission issued an order in which net energy metering would continue for new on-site DER projects, and DER projects placed into service after January 1, 2020 would take service under a value-based tariff in which the customer would receive monetary credits for net hourly injections at the calculated VDER.[12]

**Q. Is the Coalition proposing application fees?**

A. The Coalition is not recommending any changes to interconnection application fees at this time. However, we are open to utilities filing for an application fee based on demonstrated administrative processing costs, and according to case DE 15-271.

**Q. Are you proposing any changes to the customer charge?**

A. No changes to the customer charge are recommended by the Coalition at this time due to a lack of data showing incremental customer costs specific costs. The Coalition is open to utilities filing supplemental customer charges for DER customers only if total customer-related costs for DER customers are higher than for non-DER customers in the same rate class. The supplemental customer charges would cover demonstrated incremental customer-related costs (i.e., for metering, billing, or interconnection) that are specific to DER customers and adequately demonstrated with competent, objective evidence. These incremental costs should be tracked in separate utility accounts in order to more easily audit the charges and ensure that one-off costs are not being charged as recurring in perpetuity.

**Q. What does the Coalition recommend in regard to grandfathering projects?**

A. HB 1116 grandfathers existing eligible customer-generators through December 31, 2040. The Coalition recommends that any customers placed in an interconnection queue between September 1, 2017 and December 31, 2020 (i.e., Phase 1 customers) also be grandfathered in their existing programs through December 31, 2040. For Phase 2 customers, the Coalition recommends a twenty-year grandfathering provision. The Coalition also recommends that customers have the option to voluntarily request a transition to alternative programs in the future (which would cancel their existing grandfathering provision).

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[11] New York Case 15-E-0751 "In the Matter of the Value of Distributed Energy Resources." Comments of the Solar Progress Partnership on an Interim Successor to Net Energy Metering. April 18, 2016.
[12] New York Case 15-E-0751 "In the Matter of the Value of Distributed Energy Resources." Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters. March 9, 2017.

**Q. Why does the Coalition recommend 20-year grandfathering for Phase 2 projects?**

A. Customers often finance or lease their solar or DER technologies, which have useful lives in excess of 30 years. The decision to lease, purchase, or finance a DER system is an investment-backed decision based on an expectation of a reasonable opportunity to recover that investment through credit for energy production over the life of the investment. In order to provide financing, underwriters will look for assurances that the customers will not be subject to program changes that could impede their ability to pay for the loans or leases.

**Q. Please summarize the optional transmission program proposed for large projects.**

A. The proposal is to create an opt-in program that enables large projects to receive a credit for demonstrated avoidance of transmission charges. Participants in this program would be required to have a utility-owned revenue-grade production meter in order to demonstrate the production, and therefore system load reduction, at the hour of coincident peak.

**Q: How does this settlement propose addressing Renewable Energy Certificates that are associated with net-metered DER production?**

A. The Coalition proposes that REC ownership remain with the customer-generator, but that utilities will work with both customers, aggregators, and other relevant third parties to better facilitate the creation of RECs by the customer-generator, and that utilities may choose to purchase RECs directly from a customer for a fixed fee. REC creation, aggregation, and sales have been historically difficult and cost-ineffective for small residential customer-generators. Utility-led facilitation and assistance with RECs may better enable residential and lower-income customer-generators to participate in reasonable opportunities to invest in DER.

## III. Data Collection, Pilot Studies and Analysis

**Q. Do you have any recommendations about measures that can help get New Hampshire to Phase 2?**

A. Yes, we recommend that, following the Commission's order in this proceeding, stakeholder working groups convene to formulate pilot studies, establish data collection requirements, and develop a VDER study methodology, all of which would run in parallel to the Phase 1 program. These measures would require approval of the Commission and ultimately would be used to inform the crediting value in Phase 2, optional tariffs, and more transparent distribution planning procedures that can leverage the value of DER.

**Q. Do you believe there are currently data gaps in the utilities' case regarding the costs and benefits of customer-generator facilities?**

A. Yes. A fair and transparent calculation of the costs and benefits of customer-generator or DER technologies adequate to support rate making requires New Hampshire-specific data and empirical evidence. The utilities did not quantify the full range of relevant costs and benefits of DER. For example, in Eversource's initial testimony it claimed "that the future costs to integrate a higher penetration of DG will be considerable."[13] Yet, when asked whether they quantified those costs, their response was "no."[14] Moreover, when asked whether Eversource quantified the benefits of distributed generation, the company responded that it discussed the benefits "in a qualitative manner."[15] Unitil applied subjective assumptions to cost of service data derived from customers without installed DER.[16] The determination of costs and benefits of DER and new crediting mechanisms cannot rely on qualitative observations or assumptions unsupported by empirical data. In order to develop more precise price signals, more granular spatial and temporal data is required, such as circuit level hourly customer demand and forecasted demand, reliability events driven by DER, and marginal cost of service studies. This data must, in turn, be incorporated into an objective analysis of both costs and benefits (avoided costs) resulting from the operation of distributed generation.

**Q. Do you have data collection recommendations?**

A. Several parties provided recommendations for data collection in written testimony and discovery. The Coalition suggests that a collaborative working group build off the recommendations in the current record and the ongoing Grid Modernization proceeding in order to develop a data collection proposal for the PUC's consideration.

**Q. Why is the Coalition proposing an independent, Commission sponsored VDER study?**

A. The Coalition is seeking a constructive approach to a value-based crediting system. Utilities are currently skeptical of the value that DER provide to all ratepayers, and are skeptical of the results of studies sponsored by DER providers. Therefore, we propose that an objective and independent party

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[13] Joint testimony of Richard C. Labrecque and Russel D. Johnson. DE 16-576. October 24, 2016. Pg. 23, lines 8-9.
[14] Eversource response to EFCA 3-003.
[15] Eversource response to EFCA 3-011.
[16] Prefiled Rebuttal Testimony of Karl R. Rábago, Docket No. DE 16-576, December 16, 2016, at pp. 21-25, p. 27, lines 12-18.

sponsored by the PUC conduct the analysis and be subject to cross examination and review by all interested parties.

Q. **Please describe the timeline for such a study.**

A. In order to implement Phase 2 by January 1, 2021 and give parties sufficient time to retrain staff and upgrade systems, the independent VDER study must be completed by early 2020. We recommend that following the Order in this case, a collaborative working group develop the data requirements and methodologies for approval by the PUC. The 2020 study would then utilize the best available data and methodologies to arrive at a VDER.

Q. **Are you envisioning a single study or would there be additional VDER studies in the future?**

A. We suggest that, once developed and approved by the PUC, the VDER study be updated every three years and utilize the best available data and methodologies at the time of the update in order to continually improve the precision of price signals and promote innovation as a way to reduce system costs.

**Q. What pilot programs are you proposing in your Settlement Agreement**?

A. The Coalition is proposing four pilot studies. These include an incentive mechanism that helps enable DER adoption by low to moderate income customers, a TOU pilot, a "Smart Energy Home" pilot, and a non-wires alternative pilot.

**Q. Please describe the low to moderate income pilot program.**

A. Adoption of DER by low to moderate income customers is currently lagging, and the intention of this program is to provide more DER opportunities for low to moderate income customers. We recommend a collaborative working group develop a pilot program that builds off the recommendation by the Office of Consumer Advocate[17] and that helps overcome barriers to DER adoption by low to moderate income customers. The Coalition recommends that the pilot include a minimum of 100 customers for each utility.

**Q. What is the TOU pilot?**

A. At present, Eversource and Liberty Utilities both have optional TOU rates for residential and small commercial customers. However, the on-peak periods are very long, do not accurately reflect the

[17] Direct testimony of Elizabeth Doherty. DE 16-576. October 24, 2016.

length of the system peak, and do not provide customers with reasonable opportunities to shift consumption to off-peak hours. For example, Liberty Utilities' on-peak period is thirteen hours long from 8 a.m. to 9 p.m., while their data shows that demand within 5% of peak occurred between 11 a.m. and 6 p.m. Similarly, Eversource's on-peak period is 13 hours and occurs 7 a.m.- 8 p.m. on non-holiday weekdays.

The objective of this pilot is to create a more actionable TOU rate that is designed to recover the underlying energy and delivery revenue requirements and send signals to customers about the high demand times that are driving additional investments and costs in generation, transmission, and primary distribution. This TOU pilot also would be developed by a collaborative working group that would recommend a specific design to the PUC for approval.

**Q. What is the "Smart Energy Home" Pilot?**

A. The objective of this optional Smart Home Rate pilot is to test rate designs such as real-time pricing, critical peak pricing, demand charges, or other structures that enable customers to adopt a variety of technologies and behaviors to manage their electricity consumption.

We envision a voluntary Smart Home Rate that send customers accurate and actionable signals customers to shift their consumption to times when the system is under-utilized.

**Q. In previous written testimony many witnesses criticized the utilities' demand charge proposals, why are you proposing they potentially be included in a pilot study here?**

A. In their written testimony, Unitil and Eversource proposed mandatory non-coincident demand charges for new distributed generation customers. To date, no State Utility Commissions have approved mandatory demand charges for residential or distributed generation customers. Moreover, very few studies focusing on residential demand charges have been conducted.[18] Given the utilities' interest in demand charges and the lack of experience or research nationwide, we are open to working with utilities to develop a more accurate and actionable optional demand-based rates than the 15- or 30-minute non-coincident charges proposed in their testimony

**Q. Please describe the non-wires alternative pilot.**

[18] Chtkara, A. Cross-Call, D. Li, B., Sherwood, J. 2016. "A Review of Alternative Rate Designs" Pg. 60. (Submitted into the record as an attachment to EFCA's response to UES 3-1).

A. The objective of this pilot is to test the concept of deploying DER to areas in order to replace or defer traditional transmission and distribution investments (such as new lines and substations). The program leverages DER as a cheaper alternative to traditional investments as a way to maintain system reliability while minimizing system costs. We recommend the pilot be designed to test incentive mechanisms that drive investments to specific areas on the grid, to collect data about the positive impact DERs can have on the distribution system, and to gain experience integrating these relatively new resources in utility planning processes and operations. This pilot will also encourage utilities to develop a better understanding of their short- and long-term marginal distribution and transmission capacity costs. An improved understanding of these values, ultimately at a feeder level, will support the development of a wide variety of cost-reducing grid modernization technologies, services, and rates.

Experience with a non-wires alternative pilot would also help inform the Phase 2 program, which credits exports at the VDER, by shedding more light on the locational values of DERs, the additional services DER can provide (voltage support, frequency regulation, etc.), and DERs' ability to defer traditional delivery investments.

**Q. Would you consider other pilots?**

A. Yes, we are open to considering additional pilot studies and are willing to work constructively in working groups to develop pilots that test various concepts and yield actionable data to inform future rate design.

## IV. Conclusion

**Q. Does the Coalition view this proposal as a significant compromise?**

A. Yes. This proposal makes several concessions in order to hasten the transition to a more modern and flexible electricity system that leverages DER technologies to reduce system costs. While there is presently significant NEM capacity allocations available for smaller projects (under 100 kW), the Coalition proposes to begin Phase 1 on September 1, 2017. At that time, new customer-generators would be subject to non-bypassable charges on all of their delivered loads, the value of their exports would be reduced by 25% of the prevailing volumetric distribution charge, and credits for excess generation would move from volumetric (kWh) to monetary. Taken together, these measures would reduce the bill savings of new customer-generators as described above. The proposal further ratchets down the value of exports for new customer-generators as of January 1, 2019 to 50% of the prevailing distribution charge. Finally, the Coalition is seeking to resolve the debate about the value of DERs by proposing an independent, Commission-sponsored Value of DER study that is informed by newly collected data and pilot studies, and will ultimately set the rate for crediting exports in the future.

**Q. Why is the Coalition making these concessions?**

A. As noted above, the Coalition would like New Hampshire to transition to a more modern grid that includes more transparent distribution planning and precise price signals that can help reduce system costs. The Coalition recognizes that more data, analysis, and experience is required to get there, so it is proposing incremental changes to the customer-generator crediting program while proposing pilot studies and data collection that can help inform the design of Phase 2. The result will be a transition to a modern, efficient electric system which enables a transactive energy marketplace with smarter price signals for consumers, and closer integration between utilities and DER providers.

**Q. Does your proposal include any flexibility or is it entirely prescriptive?**

A. The Coalition's proposal is not intended to be prescriptive. Rather, it is intended to provide the PUC with flexibility to adapt the program and develop more precise valuation and pricing signals in the future. The proposal seeks to foster collaborative stakeholder engagement on pilot studies and alternative rate designs that will ultimately require PUC approval.

**Q. Should utilities receive timely recovery of costs associated with data collection, billing and metering system upgrades, and pilot programs?**

A. Yes, the Coalition believes these measures are in the interest of all ratepayers and supports the timely recovery of the costs related to enhanced data collection, upgrading billing and metering systems, and pilot programs, subject to regulatory oversight and approval.

**Q. Why is the Coalition's proposal in the public interest?**

A. The Coalition's proposal seeks a gradual transition away from net energy metering to a program with more precise signals about system costs in order to maximize the benefits that DER can provide to all ratepayers. The Coalition believes a methodical, transparent and data-driven approach will enable the New Hampshire DER industry to continue to grow and innovate, while also advancing the interests of the State to the benefit of all ratepayers. The proposal reduces the value of the DER energy export credits in the near term, and lays the groundwork for more precise price signals and transparent distribution planning procedures to minimize system costs. The cost of energy is at a 10-year low, and dropping. Yet the cost of retail electricity is rising—due primarily to soaring transmission and distribution costs. As seen in Figure 1, New Hampshire's distributed solar capacity is lagging behind its New England. On a population normalized basis, New Hampshire has about 41 watts of distributed solar per capita, compared to 78-, 196-, and 317 watts/capita in Connecticut, Massachusetts, and Vermont, respectively.[19] If DER development in New Hampshire does not keep pace with neighboring states, New Hampshire's ratepayers share of the region's transmission costs will increase. A properly designed policy to integrate distributed energy resources into the grid, as contemplated in this settlement proposal, can unleash the power of the free market to help contain rising infrastructure costs by incentivizing those private investments that will save ratepayers the most money.

This proposal fairly balances the many objectives of HB 1116 and seeks to create a more modern grid that minimizes total system costs while maximizing the value DER can provide to all New Hampshire ratepayers.

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

A: Yes.

[19] Victoria Rojo. February 28, 2017. "December 2016 Distributed Generation Survey Results." ISO-NE Distributed Generation Forecast Working Group. 2014 population data to normalizing the capacity was retrieved from the U.S. Census Bureau.

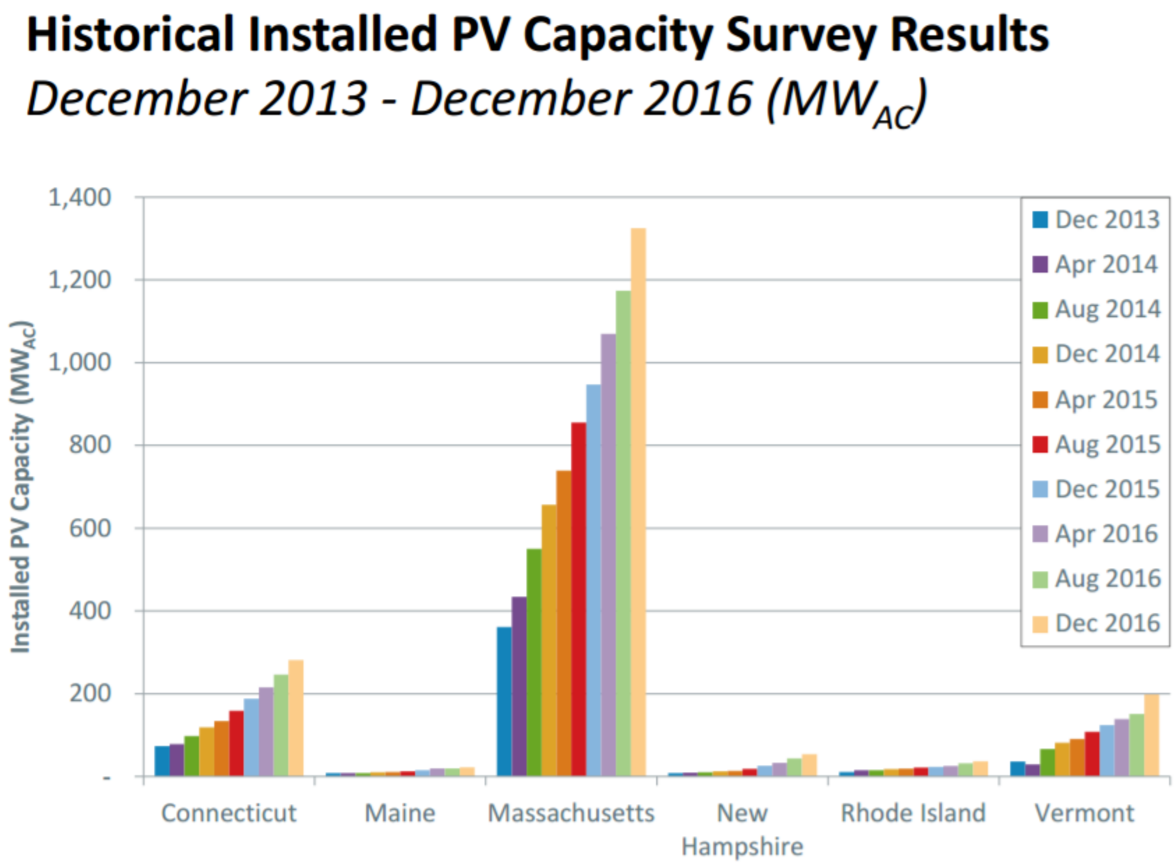


Figure 1 – Historical Installed Distributed Solar Capacity. Source: Victoria Rojo. February 28, 2017. "December 2016 Distributed Generation Survey Results." ISO-NE Distributed Generation Forecast Working Group.

STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

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

# JOINT SUPPLEMENTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF CONSERVATION LAW FOUNDATION

AND

ELLEN HAWES

ON BEHALF OF ACADIA CENTER

MARCH 10, 2017

**Q: Are you the same Paul Chernick and Ellen Hawes who previously filed testimony in this proceeding, on behalf of Conservation Law Foundation and Acadia Center, respectively?**

A: Yes.

**Q: What is the scope of your joint supplemental testimony?**

A: This joint supplemental testimony explains and supports the settlement filed on this day by a group of parties jointly referred to as the Energy Future Coalition, which is comprised of Acadia Center, the Alliance for Solar Choice, Borrego Solar, Conservation Law Foundation ("CLF"), the Energy Freedom Coalition of America, Granite State Hydropower Association, the New Hampshire Sustainable Energy Association, Sunraise Investments, Solar Endeavors, ReVision Energy, and Revolution Energy. For convenience, we refer to that settlement herein as the Joint Settlement.

**Q: Please describe the Joint Settlement.**

A: The Joint Settlement represents the current consensus among participating parties as to the appropriate ratemaking treatment of distributed generation and net metering in New Hampshire. It reflects the efforts of the participating parties to reach agreement and compromise, as well as recent work in the net-metering docket to come to a shared understanding among all of the parties. These efforts have been guided by the statutory directives reflected in HB 1116, which prompted this proceeding, and by the Commission's Order of May 19, 2016 opening this docket. While this settlement may differ in certain important respects from the positions of the utilities, the conversations in this docket have increased mutual understanding. As a result, we anticipate that there will also be numerous commonalities among the positions of the parties participating in this settlement agreement and the utilities' current positions.

From our perspective, one of the most important aspects of the Joint Settlement is the agreement to move in phased but rapid steps toward a value-based rate structure, which we recommend include time-varying rates and netting by time of use period, following the completion of key studies, information-gathering, and pilots designed to support and advance this transition.

**Q: Please summarize the content of the Joint Settlement.**

A: The Joint Settlement is described in more detail in the Joint Supplemental Testimony of Thomas Beach, Patrick Bean, Kate Epsen, Fortunat Mueller, Nathan Phelps, and Karl Rabago. In short, it provides for two phases of modification to the existing net metering rate structure. The Joint Settlement proposes that all projects placed into the interconnection queue beginning on September 1, 2017 will be subject to the Phase 1 program design. Phase I would include a transition to a new tariff on September 1, 2017, with customers taking service under the old program until the utilities have updated their billing systems to make billing under the new tariff possible. This transition would include a number of changes to the method and levels of compensating distributed-generation customers for excess generation. For projects under 100 kW, these changes include:

- Banking of excess (or exported) kWh would be eliminated as of September 1, 2017 and replaced with monetary credits that would not expire until they are used by the customer.
- As of September 1, 2017, the export credit for gross exports would exclude non-bypassable charges for the state electricity consumption tax and to support low-income programs, energy-efficiency programs, and utility recovery of stranded costs.
- The distribution credit for projects entering the interconnection queue after August 31, 2017 would be 75% of the volumetric distribution charge for their rate class for monthly net exports.

- The distribution credit for projects entering the interconnection queue after December 31, 2018 would be 50% of the current volumetric distribution rate.
- The export credit for generation and transmission would remain at the retail rate.

Phase I would also include a number of pilots consistent with HB 1116 and the Commission's May 19, 2016 Order, and other studies and information collection to support the transition to value-based rates for distributed energy resources in Phase II, which would begin January 1, 2021.

The Phase II value of distributed energy resources (VDER) rates would be firmly supported by actual data, avoiding the arbitrary tariff structures in some of the proposals in this docket and reflecting the actual value of different forms and aspects of distributed generation. We anticipate and recommend that the VDER tariff would incorporate pricing and compensation based on time of consumption and production.

**Q: What is the benefit of a transition to value-based compensation?**

A: Traditional net metering is generally considered to represent a rough approximation of the benefit of distributed generation. In contrast, cost-based valuation of the benefits and costs of distributed resources (e.g., generation, energy storage, and demand response) to the utilities and their customers should better encourage consumers, the utilities and third parties to pursue the types of distributed resources that are beneficial to ratepayers and the state as a whole, eliminating potential cross subsidies to or by distributed-generation customers. It expands consumer choice, maintains the ability of ratepayers to understand and control their bills, increases transparency, facilitates lower-cost and higher-benefit investments, and has the greatest potential to help reduce the high generation, distribution and transmission costs that New Hampshire ratepayers currently face.

**Q: What is the benefit of a transition to time-of-use (TOU) rates for distributed energy resources?**

A: The value of each type of distributed resource is determined with the time pattern of the energy it delivers to the system directly (as exported energy) or indirectly (as reduction in the host customer's load). The daily and seasonal patterns of energy production are very different for photovoltaic systems with different orientations, with more east-facing systems producing more energy in the morning, south-facing systems producing more in the middle of the day, and west-facing system producing more in the afternoon. Orientation and tilt of the panels also affects the seasonal production patterns. Other distributed generation (small wind, biogas, combined heat and power) will have even more varied patterns. Energy storage will enable a user to consume energy in low-cost periods, and return it in high-cost hours, whatever those are over time. Technology-neutral time-of-use charges and credits will automatically price these complex patterns in a more fair and accurate manner.

Many parts of the electric system have costs that are driven by the timing of consumption of generation. The costs of energy consumption and the benefits of distributed energy production vary over the day, in response to changes in the marginal price of energy, contribution to the summer daytime peaks that drive generation capacity and cost, contribution to the monthly peak hours that drive transmission cost allocation, and contribution to peaks and other high loads on various parts of the distribution system. The value of the average kWh provided by the various types of distributed resources will similarly vary widely. Any ratemaking scheme with constant energy prices will fail to capture these differences, particularly as applied to a range of different investments and actions, and hence will give misleading price signals regarding the economics of the alternatives.[1]

Over time, the time pattern of the value of energy provided or consumed will change. As renewables and efficiency reduce New England's natural-gas

[1] Pricing structures with charges for the customer's maximum demand would be even worse.

consumption, the current winter premium for gas (and hence electric energy) will decline. If photovoltaics become a large share of New England capacity, the current mid-day summer peaks are likely to move later in the day. Other changes in supply (e.g., Canadian imports, off-shore wind) and demand (e.g., electric vehicles, efficient electric heating) may shift cost patterns in other ways. A pricing system based on cost by time of use can be updated easily to reflect these changes.

To be clear, however, we recommend adopting time-of-use rates for other New Hampshire customers as well, not solely customers with DER. Acadia Center and CLF have made this clear in the ongoing grid modernization docket, IR 15-296.

**Q. How should TOU rates be integrated into net metering?**

A. When TOU rates become available, netting should be done on a TOU basis. The simplest version of TOU netting uses two numbers at the end of the billing period – (1) net imports or exports off-peak (netted over the course of the month) and (2) net imports or exports on-peak (netted over the course of the month). Unlike two-channel instantaneous netting, time-of-use rates and netting by time-of-use period provides good temporal incentives for customers to manage their load and use dispatchable DER like energy storage.

**Q: The Joint Settlement contains significant decreases in the distribution portion of the credits that customers with distributed generation receive. Please state your position on the distribution portion of the credit.**

A: Dramatic cuts to distribution credits are not supported by the data in the record, and are unlikely to fully compensate solar for its value to the system. While we are able to support the proposed reductions in distribution credits as a short-term component of the settlement, it is important that the Commission recognize that the proposed reductions are arbitrary and presented as part of a proposed compromise package. The proper level of compensation for reducing loads on the distribution system can be addressed by more complete data collection and analysis, consistent with the process proposed in the Joint Settlement. Without the data collection and pilot initiatives reflected in Phase I, together with a commitment to transition to a more accurate and less arbitrary Phase II credits, the near-term reduction in the distribution credits would be inappropriate. We understand that many of the settling parties (including our clients) would be unlikely to support the Joint Settlement without the transition to value-based credits in Phase II.

**Q: How does the prevalence of distributed energy resources in New Hampshire compare to other states?**

A: As indicated in Mr. Chernick's initial testimony, New Hampshire has relatively little distributed generation compared to a number of other states in the region, and much less than national leaders in distributed generation. In part as a result of the relatively nascent presence of distributed energy resources in the state, it is unlikely that significant cost under-recovery or cost-shifting is taking place. The low penetration of distributed resources in New Hampshire will not require expensive grid modifications and upgrades. Certainly as compared to the benefits of distributed generation, any costs or other adverse effects can be expected to be de minimis. Indeed, the utilities have largely conceded as much in their testimony.

Given New Hampshire's low penetration of distributed energy resources, modest changes to the existing net metering would be sufficient, but the greater effort to implement a more sophisticated tariff structure reflecting cost variation by time of use is warranted to support transparent, accurate pricing in the medium- and long-term, reflecting the benefits of a range of distributed resources. Refined price signals will increase the value of distributed energy resources (generation, storage, and demand response), while maintaining equity among customers.

**Q: Do additional considerations argue for additional data collection and analysis prior to the transition to fully cost-based net-metering rates in 2021?**

A: Yes. Over the course of this proceeding, the utilities have demonstrated a scarcity of information about their own systems, which has the potential to adversely affect costs and reliability. The limited information of the New Hampshire utilities on the pattern of loads on their feeders and substations also prevents optimal planning for DER integration and needs to be addressed sooner rather than later for all of these reasons.

A Non-Wires Alternative pilot, as described in the joint testimony filed by Beach, Bean, Epsen, Mueller, Phelps, and Rabago, would refine estimates of the ability of targeted distributed generation to avoid costly upgrades to the transmission grid. As described in Ms. Hawes's initial testimony and discovery responses, pilots in other states have shown this to be possible, but New Hampshire utilities need to develop the supporting planning tools and a demonstrate of local application of this approach.

If New Hampshire continues to fall behind other regional states in both energy efficiency and distributed-generation investment, its distribution costs and its share of regional transmission and generation costs will increase.

**Q: What comments do you have on monetary crediting and bidirectional metering?**

A: Monetary crediting and bidirectional metering allow the rate structure to differentiate between the embedded-cost retail rate for energy received, including non-bypassable and unavoidable costs described in the Joint Settlement, and the full marginal-cost value of energy exported.

**Q: Are low-income customers as a specific customer group identified and addressed in the Joint Settlement?**

A: Low-income customers as a specific subset of electric customers are benefited in two particular ways. First, the settlement proposes to create a range of "non-bypassable charges" that must be paid by all customer-generators. These non-bypassable charges include the System Benefits Charge, the funds from which are directed to low-income programming specifically as well as energy efficiency programs that include a carve-out benefiting the state's low-income residents. Second, the Settlement Agreement adopts a pilot, consistent with a proposal advanced earlier in this proceeding by the Office of the Consumer Advocate, which will test the benefits of an adder for power delivered by distributed resource projects of low- and moderate-income residents, to support increased participation by this customer segment.

**Q: Are there any key distinctions between small, largely residential, customer generators and the owners of larger distributed energy systems?**

A: Yes. Although both share a general need for certainty and transparency, it is more vital that smaller customer-generators have a simple rate structure. This is partly why traditional net metering was created: to provide a simple compensation mechanism for these small distributed generators that was easy for the utilities to implement and easy for customers to understand. In transitioning to any new rates or rate structures, it is essential to continue to prioritize simplicity, ease of understanding, and predictability for smaller customers.

**Q: How does the Joint Settlement satisfy HB 1116 and the Commission's May 19, 2016 Order?**

A: In spring 2016, the New Hampshire legislature passed HB 1116, which increased the state-wide cap on total net metered projects from 50 megawatts to 100 megawatts and required the PUC to initiate a proceeding to develop alternative net metering tariffs. Specifically, HB 1116 directed that the Commission:[2]

> *shall initiate* a proceeding to develop net alternative net metering tariffs, which *may include* other regulatory mechanisms and tariffs for customer-generators, and

[2] Emphasis added.

> *determine* whether and to what extent such tariffs should be limited in their availability within each electric distribution utility's service territory. In developing such alternative tariffs and any limitations in their availability, the commission *shall consider*: the costs and benefits of customer-generator facilities; an avoidance of unjust and unreasonable cost shifting; rate effects on all customers; alternative rate structures, including time based tariffs pursuant to paragraph VIII; whether there should be a limitation on the amount of generating capacity eligible for such tariffs; the size of facilities eligible to receive net metering tariffs; timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; and electric distribution utility's administrative processes required to implement such tariffs and related regulatory mechanisms. The 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 that it finds to be just and reasonable in the adoption of alternative tariffs for customer-generators. The commission *may approve* time and/or size limited pilots of alternative tariffs.

Regarding its purpose, HB 1116 explained that:

> to promote energy independence, and local renewable energy resources, the general court finds that it is in the public interest to continue to provide reasonable opportunities for electric customers to invest in and interconnect customer-generators facilities and receive fair compensation for such locally produced power while ensuring costs and benefits are fairly and transparently allocated among all customers. The general court continues to promote a balanced energy policy that supports economic growth and promotes energy diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits, a fair allocation of cost and benefits, and a modern and flexible electric grid that provides benefits for all ratepayers.

Consistent with HB 1116, on May 19, 2016, the Commission issued an Order initiating a proceeding to address the issues enumerated in HB 1116 in light of the purpose statement of HB 1116, and also to address, *inter alia*:

1. The performance of marginal cost of service studies by the three regulated electric distribution utilities and the anticipated completion of filing dates for such studies.
2. The timing and sequence of filing by the three regulated electric distribution utilities and other parties of proposed alternative net metering tariffs, which may include other regulatory mechanisms and tariffs for customer-generators.

3. The extent to which any such tariff or alternative filing must be supported by pre-filed written testimony and related studies and documentation.

This settlement is consistent with the purposes and directives of HB 1116, as well as the Commission's Order. It furthers each of the purposes of HB 1116, including but not limited to the development of competitive markets and customer choice, and, to the extent possible given the limits of currently available data, weighs factors such as the costs and benefits provided by distributed resources, potential cost-shifting, and prompt utility cost recovery. Through value-based tariffs, it advances the objective of lowering rates and improving price signals. The pilots, VDER study, and other information-gathering detailed in the Joint Settlement each address elements of the statute and the Commission's Order, and further policy objectives of the state that include reducing electric rates and enhancing competitive energy options.

**Q: Please summarize your recommendations.**

A: CLF and Acadia Center both support the transition to a clean, smart energy future that empowers customers and enables the integration of distributed energy resources in a manner that protects both utility and consumer interests. We believe this settlement agreement will benefit New Hampshire ratepayers by facilitating the transition to value-based tariffs for distributed energy resources, while avoiding excessive, arbitrary, abrupt and confusing jumps in compensation rates. While the Joint Settlement reflects many areas of compromise, we believe that it is a reasonable overall approach to satisfy HB 1116 and the Commission's May 19, 2016 Order, while advancing multiple important state policy interests, including reducing ratepayer bills, enhancing consumer protections, ensuring accurate and complete cost recovery, and promoting sound infrastructure investments on both sides of the meter. We further believe that the multi-step nature of this settlement will provide a gradual transition that aligns with pending efforts to modernize New Hampshire's electric grid and rate offerings, including the opportunity to provide time-variant price signals, while providing a pathway to long-term solutions that can support cost-reducing competition and innovation, including technologies not yet developed.

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

A: Yes.

**PretiFlaherty**

Portland, ME
Augusta, ME
Concord, NH
Boston, MA
Washington, DC

Todd J. Griset
tgriset@preti.com

March 10, 2017

Debra Howland, Executive Director
New Hampshire Public Utilities Commission
21 South Street, Suite 10
Concord, NH 03301

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

Dear Ms. Howland:

On behalf of the Energy Future Coalition ("Coalition"), a coalition of parties in the above referenced matter which is comprised of Acadia Center, The Alliance for Solar Choice, Borrego Solar, Conservation Law Foundation, Energy Freedom Coalition of America, LLC, New Hampshire Sustainable Energy Association, ReVision Energy, Granite State Hydropower Association, Sunraise Investments LLC, Solar Endeavors LLC, and Revolution Energy, LLC, I enclose for filing the original and six copies of documents presenting the Coalition's Joint Settlement Proposal, including the Supplemental Settlement Testimony of R. Thomas Beach, Patrick Bean, Kate Basford Epsen, Fortunat Mueller, Nathan Phelps, and Karl R. Rábago; and the Joint Supplemental Testimony of Paul Chernick and Ellen Hawes.

Thank you for your attention and assistance in this matter.

Sincerely,

Todd J. Griset

Enclosures

cc: Docket Service List (via email)

TJG:mkm