THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 16-576

ELECTRIC DISTRIBUTION UTILITIES

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

EXHIBIT
#46

PREFILED REBUTTAL TESTIMONY OF PATRICK BEAN

ON BEHALF OF THE ENERGY FREEDOM COALITION OF AMERICA

Q. 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. My business address is 601 13th Street NW, Suite 900, Washington, DC 20005. I am filing testimony on behalf of the Energy Freedom Coalition of America (EFCA).

Q. Have you previously submitted testimony in this docket?

A. Yes, I filed testimony on behalf of EFCA on October 24, 2016.

Q. What is the purpose of your rebuttal testimony?

A. I address the alternative tariff proposals from Eversource, Unitil, and the Office of Consumer Advocate (OCA). I also respond to the unique circumstances of this proceeding, in which utilities and others have proposed drastic and abrupt changes to the net metering program but lack the advanced metering technology and data to enable customers and distributed energy resource (DER) providers to maximize the value of DERs. I therefore offer additional recommendations for developing and monitoring non-wires alternatives and time-of-use pilots programs.

Q. Please summarize Eversource's alternative tariff proposal.

A. Eversource proposes a tariff with two-channel billing (i.e., separate billing for all electricity delivered to the customer, and all electricity provided from the customer to the utility) that includes non-coincident demand charges and compensation for a customer's monthly excess generation at the Company's avoided cost rate. The demand charges would be based on a customer's maximum 30-minute demand in the billing month, and be assessed at a rate of $5.82/kW for distribution charges and $3.31/kW for transmission charges.[1] The company proposes that customers who receive a net metering capacity allocation for a qualified distributed generation (DG) facility on and after the implementation date of the new tariff would be subject to the tariff. The company also proposes that customers that have capacity allocations above the current net metering cap and were allowed to take service under the current net metering provisions will transition to the new tariff upon its implementation.[2]

[1] Direct Testimony of Edward A. Davis, Attachment 2.
[2] Direct Testimony of Edward A. Davis, pg. 2-3.

Q. Does transitioning customers that are allowed to take service under the current net metering tariff to a new tariff upon its implementation create investment uncertainty for possible distributed generation customers?

A. Yes. Under this type of scenario, New Hampshire would likely see a freeze in customers adopting DG because it would be impossible for a potential customer to estimate their savings since the details and timing of the new tariff would be uncertain at the time of investment. It would also send the wrong signal to customers and businesses that New Hampshire may not have a stable business environment. To provide customers with greater investment certainty for distributed generation, new net metering customers should be allowed to take service under the current net metering tariff for twenty years if new alternative tariffs have yet to be developed by the time New Hampshire utilities hit their net metering capacity allocations.

Q. Please summarize Unitil's alternative tariff proposal.

A. Similar to Eversource's alternative tariff proposal, Unitil is proposing a tariff with two-channel billing (i.e., separate billing for all electricity delivered to the customer, and all electricity provided from the customer to the utility) that includes a non-coincident demand charge and compensation for a customer's monthly excess generation at the average locational marginal price for the New Hampshire load zone for the calendar month prior to the current billing month.[3] The demand charge would be based on a customer's maximum 15-minute demand, and be assessed at a rate of $5.32/kW for distribution charges.[4] The monthly fixed charge is $15, which is an increase from the current $10.29 monthly fixed charge.

Q. Did Unitil evaluate how its alternative tariff proposal would impact the development of net metering projects in New Hampshire?

A. No. In response to Staff's inquiry about the impact of Unitil's proposed alternative tariff on the development of net metering projects in New Hampshire, Unitil stated that "The Company has not developed any specific studies or evaluations."[5]

Q. Does Unitil's proposal credit DG customers for electricity sent to the grid?

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[3] Supplemental Testimony of H. Edwin Overcast, Supplemental-1 (Schedule DDER).
[4] Ibid.
[5] Unitil response to Staff-UES 3-08.

A. Only when the monthly generation flowing to the grid is greater than the energy delivered to the customer. Otherwise the customer does not get credit for any generation flowing to the grid. According to the proposed rate schedule,[6] net KWh for crediting purposes is calculated as kWh of "usage" from the production channel (i.e., generation flowing to the grid) less the kWh from the usage channel (i.e., generation flowing from the grid to customer) over the billing month, if it is greater than zero. For example, if a customer sends 25 kWh to the grid and gets 15 kWh delivered from the utility, the customer would have a net 10 kWh for crediting purposes that month. Further, the customer is credited only at "avoided costs". However, if the customer sends 20 kWh to the grid and receives 50 kWh from the utility, the customer would not be credited for the 20 kWh he or she sends to the grid. Moreover, the customer does not get any credit applied to the 50 kWh as the proposed rate schedule states that *all energy delivered*, rather than net energy delivered, is subject to external delivery, stranded cost, storm recovery, system benefits and default service charges.

Q. Will customers receive adequate and timely information about their demand from Unitil and Eversource?

A. No. Unitil stated that it is has no intent to provide customers with the timing of its fifteen minute demand, nor does it believe it is a reasonable requirement to do so.[7] Customers would learn the kW quantity of their maximum 15-minute demand only when they receive their bill. Likewise, Eversource stated that customers would learn of their maximum 30-minute demand when they receive their monthly bill, and the company will not provide the exact time when the maximum demand occurred.[8]

Q. Would customers have the ability to respond and reduce their demand given the lack of information provided by the utilities?

A. No. A customer obviously cannot reduce its maximum demand if they receive a signal (in this case their monthly bill) after their maximum demand has occurred. Nor is it evident whether the timing of the customer's demand was actually preferable, such as an off-peak period when excess capacity is available. Additionally, the lack of information about the timing of their maximum demand denies the ability for customers to change their behavior to reduce maximum demand in the future. For example, a customer that learns their peak demand in the previous month was 5 kW will be left guessing as to when the demand occurred and what caused it. Was it the 15 minutes that the air conditioner, dryer

[6] Unitil Schedule HEO Supplemental-1 submitted with Supplemental Testimony of Edwin Overcast.
[7] Unitil response to TASC-UES 3-07.
[8] Eversource response to TASC 3-11.

and iron were running at the same time? Or maybe it was when the hot water heater, coffee maker and toaster were running in unison? Even if a customer had a reasonable grasp on the wattage of all the items in their home, the non-coincident nature and short measurement intervals (15-minute for Unitil and 30-minute for Eversource) makes it difficult for customers to reduce demand since they must constantly monitor usage over short-intervals. Customers would need to monitor nearly 3,000 measurement intervals in a typical month under Unitil's proposal. For these reasons and others, non-coincident demand charges effectively act as a fixed charge.[9] The proposed design makes it difficult for customers to confidently and accurately reduce demand or invest in distributed generation. Eversource recommended that customers install equipment costing several hundred dollars in order to monitor and learn more about their demand.[10] This would simply depict the 3,000 measurement intervals, not reduce or simplify them. Unitil says customers can rely on information provided by DG suppliers to make estimates about potential bill savings.[11]

Q. Would Unitil and Eversource be able to provide customers with sufficient billing and demand data to make informed choices in the market? A. No. There is little utility experience and empirical data about residential demand charges. [12] That, coupled with a lack of data from utilities and the inherent uncertainty about billed demand from month to month, makes it nearly impossible for customers to confidently estimate potential bill savings.

Q. Please provide a summary of OCA's alternative tariff proposals.

A. The OCA provided two alternative tariff proposals. The first is a "DG TOU Rate" which includes two-channel billing, time-of-use delivery charges with a 2pm-8pm peak period, charges for exports, and non-bypassable charges. The second is a "Fixed Solar Credit Rate" which is a buy-all/credit-all approach that provides DG customers with a fixed 20-year delivery credit for all energy produced. The fixed credits are set in advanced in a series of tranches, with each tranche representing incremental capacity with successively lower credit rates.

Q. Is OCA's DG TOU Rate proposal an appropriate alternative tariff?

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[9] Chitkara, A., Cross-Call, D., Li, B., Sherwood, J. 2016. *A Review of Alternative Rate Designs*. Rocky Mountain Institute. At pg. 63.
[10] Eversource response to TASC 3-11.
[11] Unitil response to TASC-UES 3-07.
[12] Chitkara, A., Cross-Call, D., Li, B., Sherwood, J. 2016. *A Review of Alternative Rate Designs*. Rocky Mountain Institute. At pg. 76 and 79.

A. While EFCA supports time-of-use alternative tariffs, the OCA's proposal is problematic. The design of the program is complex and may lead to customer confusion due to the number of billing components and determinants. For example, a customer will be billed for non-bypassable transmission, stranded cost, storm recovery, system benefits and tax charges based on their gross consumption. For a customer's hourly net positive consumption, they will be billed for default energy service, and delivery charges which differ by peak and off-peak periods. Finally, for a customer's hourly net negative consumption (i.e., providing excess generation to the grid), the customer gets credit for default energy service and delivery charges differing by peak and off-peak less a 4 cent/kWh hourly export charge. This will make customer bills difficult to understand. This also leads to another potential problem in that customers could be receiving credit below avoided cost for excess generation. For example, a Unitil customer producing one kWh of excess generation off-peak would be credited about 2.8 cents[13] while the average 2015 avoided cost was about 4.7 cents.[14]

Q. Did OCA evaluate how its DG TOU Rate proposal would impact the development of net metering projects in New Hampshire?

A. It does not appear that OCA witness Huber conducted such an analysis. OCA witness Huber's "LH8 – TOU and Offset.xlsx" worksheet provided in response to TASC 1-1 calculates annual bills for non-DG customers. OCA witness Huber also provides a "Solar Offset on TOU Rate" but it is unclear how values were calculated as they do not include or show formulas.

Q. Please summarize OCA's expectations for its Fixed Solar Credit Rate.

A. OCA witness Huber estimates that the Fixed Solar Credit Rate option would lead to 200 MW of incremental DG systems at a substantially reduced cost to customers compared to full retail net metering.[15]

Q. What is the basis of OCA's 200 MW estimate?

A. OCA witness Huber utilized a modified version of the National Renewable Energy Laboratory's publically available Cost of Renewable Energy Spreadsheet Tool ("CREST") to calculate the levelized revenue requirement of five small scale PV market segments. OCA contracted with Sustainable Energy Advantage ("SEA") to conduct a market potential study based on the proposed

[13] 7.69 c/kWh energy service + 0.15 c/kWh off peak T&D – 4 c/kWh hourly export charge – 1 c/kWh non-bypassable transmission charge.
[14] Based on Unitil response to Staff-UES 3-04.
[15] Direct Testimony of Lon Huber, pg. 32-33.

tranches and levelized revenue requirements calculated by OCA witness Huber. SEA found a total economic potential of 653 MW of DG at the proposed tranche levels.

Q. Is SEA's analysis of the Fixed Solar Credit Rate's economic potential accurate?

A. It is unclear whether SEA's analysis is accurate. A proper assessment of SEA's analysis was not possible due to the OCA's objections to requests by Staff and EFCA for data, assumptions and workpapers used in SEA's analysis.[16]

Q. Please explain the modifications to CREST made by OCA witness Huber.

A. As noted above, OCA witness Huber utilized CREST to calculate the levelized revenue requirement of five small scale PV market segments. Witness Huber modified CREST to include changes to bonus depreciation and the federal investment tax credit scheduled to occur between 2017 and 2022, and solar cost reductions he assumed to occur during that time. This enabled him to calculate revenue requirements for systems in service in each year between 2017 and 2022 and for each of the five market segments. The subsequent 30 levelized revenue requirements were presented on pg. 59 of OCA witness Huber's testimony.

Q. Are there any problems with OCA's CREST analysis used to determine the economic viability of the Fixed Solar Credit Rate?

A. Yes. CREST includes two flags on the "Inputs" tab[17] and "Summary Results" tab[18] that check whether the projects achieve an annual minimum debt service coverage ratio ("DSCR") and a required average DSCR. Debt service coverage ratio measures the ratio of cash available to service debt payments and is a metric used to assess the ability of a person or organization to meet their debt obligations and is a measurement of the ability to obtain financing. OCA's analysis included a required minimum annual DSCR of 1.2 and a required average DSCR of 1.35. None of OCA's 30 calculated revenue requirements met both DSCR requirements. Therefore, the levelized revenue requirements based on the inputs and assumptions from OCA witness Huber's testimony are underestimated. This calls the economic viability of the Fixed Solar Credit Rate into question since the CREST analysis was used to inform the design of the program and SEA's assessment of its potential. To meet the DSCR requirements, CREST suggests that users should reduce debt levels or

[16] OCA response to Staff 1-1, EFCA 1-26, EFCA 1-30, EFCA 1-33, and EFCA 1-36.
[17] Cells G61 and G64.
[18] Cells D10 and D11.

increase the target after-tax equity internal rate of return. Both actions increase financing costs, and thus would lead to higher levelized revenue requirements.

Q. Do you have any recommendations for the Commission based on the development of this case thus far?

A. This case so far is notable for the breadth of topics being analyzed and considered due in part to the legislative requirements of HB 1116. Despite the extensive opportunity for discovery, it is clear that data and processes critical to evaluating and developing opportunities for DER that maximize grid value are not readily available due to a lack of advanced metering infrastructure and collaborative opportunities. Moreover, the alternative tariff proposals set forth from the utilities and several other intervenors are dramatic departures from the current net metering program and have yet to be adopted or readily tested in other jurisdictions. Some intervenors have recommended these proposals go into effect at the conclusion of this docket despite Eversource, Liberty Utilities, and Unitil having 44.7 MW,[19] 4.9 MW,[20] and 5.77 MW,[21] of available capacity within the current net metering cap, respectively. Therefore, I recommend the Commission develop pilot programs that test potential alternatives and collect data over the next two years to provide greater advanced notice and visibility about future alternative tariffs while the current net metering programs are subscribed. Doing so will provide utilities, customers and DER providers with adequate time to plan and be prepared for changes in the net metering program.

Q. Do you have any recommendations for developing a time-of-use pilot that you proposed in your initial testimony?

A. Yes, I suggest the Commission and stakeholders collaboratively develop a "Study and Evaluation Plan" for all alternative net metering pilot programs created as a result of this docket. Doing so can help aid in the collection of appropriate data, the selection (and standardization) of methodologies and monitoring of customer satisfaction and impacts on utility revenue recovery.

Q. Is there a recent example of a "Study and Evaluation Plan" for a TOU pilot that serves as a guide for New Hampshire?

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[19] Eversource Net Metering Program Capacity as of 12/9/2016 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

[20] Liberty Utilities Net Metering Program Capacity as of 12/16/2016 https://new-hampshire.libertyutilities.com/uploads/NetMeteringWeeklyStatusReportv%20dec16.pdf

[21] Unitil Net Metering Program Capacity as of 10/21/2016. http://unitil.com/energy-for-residents/electric-information/distributed-energy-resources/net-metering

A. Yes, in November 2016, the Public Service Commission of Colorado approved a settlement agreement for Xcel Energy that included the development of a trial TOU program to precede the potential full-scale rollout of residential TOU rates.[22] On November 15, 2016, Xcel Energy filed a "Study and Evaluation Plan" that outlined details of the TOU trial that will begin enrolling customers on April 1, 2017.[23] A copy of Xcel's "Study and Evaluation Plan" is attached as Exhibit 1. The plan includes a variety of useful information that can help guide the development of a TOU pilot in New Hampshire, particularly an outline of study objectives.

Q. Do you have any additional recommendations for developing a non-wires alternative (NWA) pilot that you proposed in your initial testimony?

A. Yes, I suggest the Commission develop guiding principles for a NWA pilot program and competitive solicitations.

Q. Are there any recent examples of guiding principles for NWA programs and NWA competitive solicitations?

A. Yes. On December 15, 2016 the California Public Utilities Commission issued a proposed decision to create a consistent regulatory framework for the guidance, planning and evaluation of integrated distributed energy resources.[24] The proposed decision includes seven guiding principles, including ensuring that ratepayers are not paying twice for the same service, and recognizing that distributed energy resources are eligible to provide multiple incremental services and be compensated for each service.[25] The proposal also includes a framework for competitive solicitations and evaluations of resources, and proposes 12 principles for the competitive solicitation framework. Some of the principles include the framework meets the identified need on a least-cost, best-fit basis, the framework is technology-neutral, and the framework is transparent as allowed within confidentiality boundaries.[26]

Q. Are there any additional features of the proposed California decision worth considering in New Hampshire?

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[22] Colorado Public Utilities Commission News Release. November 9, 2016. Available from: https://drive.google.com/file/d/0B_jCd57KPowidzEtSmJWYzdLNWc/view
[23] Colorado PUC, Proceeding No. 16AL-0048E. *2017-2019 RE-TOU & RD-TDR Study and Evaluation Study*. Filed November 15, 2016.
[24] Proposed Decision before the California Public Utilities Commission. 12/15/16. Agenda ID# 15332, Rulemaking 14-10-003. Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot.
[25] Ibid at pg. 78.
[26] Ibid at pg. 78-79.

A. Yes, the proposed decision includes a utility regulatory incentive pilot which provides the utility with a 4 percent pre-tax incentive applied to the annual payment for distributed energy resources that successfully avoid or defer an otherwise planned utility expenditure.[27] Such a mechanism may incentivize utilities to more actively consider distributed energy resources in their distribution planning and procurement processes, as well as operations, in order to maximize the value of such resources.

Q. **Does this conclude your testimony?**

A. Yes it does.

[27] Ibid at pg. 86.