

**STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION**

DE 16-576

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

**Order Accepting Settlement Provisions, Resolving Settlement Issues,
and Adopting a New Alternative Net Metering Tariff**

ORDER NO. 26,029

June 23, 2017

APPEARANCES: Matthew J. Fossum, Esq., on behalf of Public Service Company of New Hampshire, d/b/a Eversource Energy; Michael J. Sheehan, Esq., on behalf of Liberty Utilities (Granite State Electric) Corp., d/b/a Liberty Utilities; Gary Epler, Esq., on behalf of Unifil Energy Systems, Inc.; Keyes, Fox & Wiedman LLP, by Thadeus B. Culley, Esq., on behalf of The Alliance for Solar Choice; Preti, Flaherty, Beliveau & Pachios, LLP, by Anthony W. Buxton, Esq., on behalf of Energy Freedom Coalition of America; Primmer Piper Eggleston & Cramer PC, by Elijah D. Emerson, Esq., on behalf of New Hampshire Sustainable Energy Association; James T. Rodier, Esq., on behalf of Freedom Logistics, LLC d/b/a Freedom Energy Logistics; Melissa E. Birchard, Esq., on behalf of Conservation Law Foundation; Stephen Hinchman, Esq., on behalf of Revision Energy; Henry Herndon, on behalf of Revolution Energy; Clifton Below, on behalf of the City of Lebanon; Chris Anderson, on behalf of Borrego Solar Systems, Inc.; Assistant Attorney General Christopher G. Aslin, Esq., on behalf of the Office of Energy Planning; Amy Boyd, Esq., on behalf of Acadia Center; Robert Hayden, on behalf of Standard Power of America, Inc.; Michael Sununu, on behalf of New England Ratepayers Association; James R. Voyles, Esq., on behalf of Consumer Energy Alliance; Lee W. Oxenham, *pro se*; Pentti J. Aalto, *pro se*; the Office of the Consumer Advocate by D. Maurice Kreis, Esq., on behalf of residential ratepayers; and David K. Wiesner, Esq., on behalf of Commission Staff.

In this Order, the Commission accepts the common elements in two settlement proposals filed in this proceeding and resolves the differences between those two settlements, providing for the adoption of an alternative net metering tariff to be in effect for a period of years while further data is collected and analyzed, pilot programs are implemented, and a distributed energy resource (DER) valuation study is conducted. During the next several years, small customer-generators (those with renewable energy systems of 100 kW or less) will net meter their distributed generation resources with monthly netting. Those customer-generators will

receive monthly excess export credits equal to the value of kWh charges for energy service and transmission service at 100 percent and distribution service at 25 percent, while paying non-bypassable charges, such as the system benefits charge, stranded cost recovery charge, other similar surcharges, and the state electricity consumption tax, on the full amount of their electricity imports from the electric grid. Systems that are installed or queued during that period of years will have their net metering rate structure “grandfathered” until December 31, 2040. Following completion of the DER valuation study, and with the availability of additional customer load and system data, the Commission will open a new proceeding to determine whether and when further changes should be made to the net metering tariff structure we approve today.

I. PROCEDURAL HISTORY

In House Bill 1116, 2016 N.H. Laws Chapter 31 (HB 1116), the legislature directed the Commission to develop a new alternative net metering tariff or tariffs, specified factors that the Commission must consider in developing those tariffs, and required the Commission to initially approve or adopt a tariff within a ten-month period. *See* RSA 362-A:9, XVI-XVII. Pursuant to that delegation, the Commission issued an Order of Notice on May 19, 2016, opening this proceeding. The Order of Notice directed that the electric distribution utilities regulated by the Commission would be mandatory parties.¹ The next day, the Office of the Consumer Advocate (OCA) filed a notice of its intent to participate in the docket pursuant to RSA 363:28. Numerous persons stated their varied interests in participating in the proceeding and were granted intervention. Following a prehearing conference and technical sessions, the Commission adopted an expedited procedural schedule designed to ensure that the Commission would meet

¹ The three regulated electric distribution utilities are Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource), Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (Liberty), and Unitil Energy Systems, Inc. (Unitil).

the legislature's ten-month timeline. That schedule was amended several times to allow the participants adequate time to prepare their testimony and to conduct necessary discovery. Many parties filed direct and/or rebuttal testimony.

On December 21, 2016, the Commission issued Order No. 25,972 adopting a net metering tariff on an interim basis to comply with the legislature's timetable. That tariff was intended to maintain the status quo until this proceeding could be completed. The Commission subsequently extended the dates set for hearing to allow the participants adequate time to prepare a more robust record for the development of a longer-term tariff. On March 2, 2017, the Commission cancelled the first week of scheduled hearings and directed parties to file settlement agreement(s) and supporting statements and/or testimony by March 10, 2017.

A settlement agreement and related technical statement was filed on that date by a coalition of utility and consumer parties (UCC), including Eversource, Liberty, Unitil, OCA, the New England Ratepayers Association (NERA), Consumer Energy Alliance (CEA), and Standard Power of America, Inc. (Standard Power) (the UCC Settlement). A Joint Settlement Proposal, with supporting supplemental testimony, was filed on the same day by a coalition of distributed generation industry advocates and environmental organizations known as the "Energy Future Coalition (EFC)," including Acadia Center, The Alliance for Solar Choice (TASC), Borrego Solar Systems, Inc., Conservation Law Foundation (CLF), Energy Freedom Coalition of America, LLC (EFCA), New Hampshire Sustainable Energy Association (NHSEA), ReVision Energy, Granite State Hydropower Association, Sunraise Investments LLC, Solar Endeavors LLC, and Revolution Energy, LLC (the EFC Settlement).² On March 22, 2017, the Office of

² The UCC Settlement and the EFC Settlement are referred to collectively as the Settlements.

Energy and Planning (OEP) filed a statement of support for the UCC Settlement and indicated it joined the UCC Settlement.

On March 24, 2017, the Commission granted a Motion in Limine to Focus the Issues at Hearing filed by CLF and other supporters of the EFC Settlement. Based on the terms of the two Settlements, the issues deemed relevant for the hearing were as follows:

- (a) New alternative tariff commencement date;
- (b) Non-bypassable charges excluded from the credit for exported electricity;
- (c) Commodity credit value and purchases from competitive suppliers;
- (d) Distribution credit value, whether no credit or a percentage of retail kWh charge;
- (e) Transmission credit value and potential avoided cost determination for large customer-generators;
- (f) Instantaneous netting or monthly netting of kWh for monetary bill credit calculation;
- (g) Renewable energy certificate (REC) purchase, aggregation, and monitoring options;
- (h) Grandfathering of queued and/or interconnected customer-generator systems in Phases 1 and 2;
- (i) Bi-directional and production meter installation, ownership, and cost provisions;
- (j) Data collection requirements and timing as described in the Settlements;
- (k) Pilot programs number, type, design, and timing as described in the Settlements;
- (l) Value of Distributed Energy Resource study design and timing;
- (m) Transition to Phase 2 net metering tariffs process and timing and design elements;
- (n) Lost revenue recovery by utilities through automatic rate adjustment mechanism;³
- (o) Community net metering for low and moderate income consumers; and
- (p) Consistency of the Settlements with applicable statutory criteria and legislative purposes.

³ Such a mechanism is often referred to as a “lost recovery adjustment mechanism” or “LRAM.”

Three full days of hearing were held on March 27, 28, and 29, and a final session for public comments and oral closing statements was conducted on March 30, 2017. A number of parties, including supporters of each of the two Settlements, filed written closing statements on April 10, 2017.

The settlement agreement filings, and other filings and documents related to this matter, can be found at <http://puc.nh.gov/Regulatory/Docketbk/2016/16-576.html>.

II. POSITIONS OF THE PARTIES AND STAFF

A. Original Positions of Parties

In order to provide background and context for the two Settlements, we will summarize the original positions of the parties and Commission Staff (Staff) before describing the Settlements.

1. Electric Distribution Utilities

Unitil, Eversource, and Liberty asserted that the current statutory net metering tariff results in unjust and unreasonable cost-shifting from customers with distributed generation (DG) to customers without DG, because net-metered customers with systems of 100 kW or less are credited at the full retail rate for exported generation and therefore do not pay an appropriate share of the embedded costs of utility transmission and distribution systems which they continue to use for both electricity imports and exports. Hearing Exhibit (Exh.) 9 at 10; Exh. 14 at 8-21; and Exh. 16 at 8-12. The utilities maintained there are no demonstrated avoided costs or other benefits of DG beyond the market value of the electricity provided through DG system exports to the grid. Exh. 9 at 17, 26-27; Exh. 14 at 23-27. Unitil claimed that DG system exports could have an adverse effect on the utility distribution system, referencing substantial distribution system upgrades required to be made by its Massachusetts affiliate to address reverse power flow

conditions resulting from high DG system penetration on certain circuits in its service territory. Exh. 8 at 10.

To address their concerns, the utilities proposed substantial changes to the current net metering tariff provisions. Unitil proposed a new tariff based on a separate DG rate class and a three-part rate structure for that DG rate class, including (1) a kW demand charge (the rate would be based on a 15-minute maximum integrated demand reading as captured by the Company's Advanced Metering Infrastructure (AMI) system each billing cycle), (2) a customer charge and (3) the energy charge billed per kWh (including time-of-use (TOU) based energy charges in the future. Exh. 9 at 21-22. The proposed demand charge would be \$5.32 per kW per month. Exh. 12 at 3; Exh. 13 at 1. According to Unitil, the proposed three-part rate structure for the new DG customer rate class would enable it to properly charge DG customers for their use of the distribution system and would provide it with the revenue needed to invest in modernization of the grid. Exh. 8 at 48-49. To further mitigate cost-shifting to other non-DG customers, Unitil proposed that "banking" of cumulative net-metered energy (kWh) credits by DG customers be eliminated. Exh. 9 at 38.

Eversource proposed a similar new rate design for net-metered DG customers that would require the installation of bi-directional meters to measure both grid power imports and exports, as well as customer peak demand. Exh. 15 at 3. According to Eversource, the proposal would address cost-shifting in two ways. The first would be to assess all distribution and transmission service charges for residential DG customers based on demand charges of \$5.82 per kW (distribution) and \$3.31 per kW (transmission) and for small commercial DG customers based on demand charges of \$10.53 per kW (distribution) and \$6.05 per kW (transmission), thus creating a class average or revenue neutral rate design. *Id.* at 4-5 and Att. 1 at 1. The second would be to

require DG customers to pay for delivery services for all purchases from the grid, which would prevent those customers from avoiding their share of certain non-bypassable charges that currently are included in volumetric kWh charges. *Id.* at 5. Those charges would be assessed on the quantities purchased by DG customers with no crediting back based on the quantities of grid exports from their DG systems. *Id.* In effect, within each monthly billing cycle, DG customers would be credited for electricity exports only at the Eversource energy service rate rather than at the full retail rate. *Id.* at 5-6. Under the Eversource proposal, any excess electricity credits unused at the end of the monthly billing cycle would be compensated at Eversource's avoided cost rate, which is based primarily on real-time locational marginal prices (LMPs) in the ISO New England (ISO-NE) regional wholesale electric market. Exh. 14 at 16; Exh. 15 at 5-6. The avoided cost rate is determined under the Public Utility Regulatory Policies Act of 1978, as amended (PURPA), on an annual basis as set forth in N.H. Code Admin. Rules Puc 903.02. Exh. 15 at 6.

Liberty proposed to reduce cost-shifting by ending the banking of energy (kWh) credits and by lowering the net metering export credit to its energy service rate rather than the full retail rate. Exh. 16 at 18-19. Liberty also proposed to install bi-directional meters to record both the kWh imported and exported over each monthly period,⁴ so all imported energy could be charged the full retail rate components regardless of grid exports during the month. *Id.* at 12, 21-22. According to Liberty, its proposal would cause all new net metering customers to be treated like those with installations of 100 kW or greater. *Id.* at 4. Liberty also proposed to install production meters for all DG customers to accurately measure utility lost revenues resulting from DG customer consumption of electricity produced behind the utility revenue meter. *Id.* at 21-22.

⁴ The word "monthly" or "month" when used in this Order refers to a customer's applicable monthly billing cycle, except where the context requires otherwise.

In their rebuttal testimony, Unitil and Eversource witnesses criticized both the scope and methodology of the TASC benefit-cost model, and maintained that only avoided energy costs should be taken into account in determining DG export compensation. Exh. 40 at 3-7; Exh. 41 at 31-32; Exh. 43 at 5-6. The two utilities reiterated their view that significant cost-shifting is occurring and must be addressed through alternative net metering rate designs. Exh. 39 at 8; Exh. 41 at 55; Exh. 43 at 27.

2. New England Ratepayer's Association

NERA argued that the current net metering system is flawed in its approach to deploying DG because of cost-shifting to other non-DG customers. Exh. 27 at 2-3. NERA claimed that solar DG does not provide any capacity benefits like traditional generation due to its intermittency, and likely imposes additional costs for ISO-NE grid management and stabilization due to potential bi-directional power flows. *Id.* at 3-7. According to NERA, the externalities claimed to represent DG benefits by solar advocates, such as carbon dioxide reduction and positive economic impacts, are already compensated to DG owners through federal income tax credits and local property tax exemptions, and through sales of RECs as required by the renewable portfolio standard (RPS). *Id.* at 14-16. NERA maintained that net metering tends to undermine energy efficiency initiatives due to full retail rate energy (kWh) credit banking that dampens the financial incentives to implement energy efficiency measures. *Id.* at 8. NERA also argued that net metering tends to distort energy market prices with potentially adverse effects on conventional generation. *Id.* at 8, 12. NERA claimed that, in order to avoid unreasonable cost-shifting, net-metered DG customers should have generation and demand measured as close to real time as possible, with recognition of associated costs and other limitations. *Id.* at 17-18, 24.

In rebuttal testimony, NERA witness Harrington maintained that DG should be treated like any other generation and compensated for energy exports at wholesale market prices. Exh. 62 at 4-5.

3. The Alliance for Solar Choice and Energy Freedom Coalition of America

TASC and EFCA are both national advocates for the solar DG industry. TASC maintained that customers who install DG should be fairly compensated for any excess power produced, while the benefits and costs from DG facilities should be allocated among all ratepayers in a fair and transparent way. Exh. 19 at i. TASC witness Beach described a benefit-cost study he performed employing methodology that considers the costs and benefits from the perspectives of various stakeholders and the general public interest. *Id.* The key attributes of the methodology he described include the consideration of a comprehensive list of benefits and costs, use of a long-term life-cycle analysis based on a 25-year study period, and a focus on net metering energy exports rather than total DG customer consumption. *Id.* at 8-10.

TASC advocated for a wider consideration of net metering benefits than purely a distribution-level cost-of-service (COS) model approach, including avoided energy, avoided generation capacity, avoided line losses, avoided ancillary services, avoided transmission and distribution (T&D) capacity, avoided environmental costs, avoided carbon emissions, avoided fuel hedging/fuel price uncertainty, market price mitigation, avoided renewables, and societal benefits. *Id.* at 21-23. TASC acknowledged that the utility distribution system incurs capital and operating and maintenance (O&M) costs from DG, and costs to integrate DG in the form of system regulation and operating reserves, program administrative costs, interconnection costs, and lost revenues due to DG customers receiving bill credits. *Id.* at 23. TASC asserted that the Commission should not assign a zero value to any cost or benefit where it is uncertain about the

magnitude of its effects, but instead should consider a range of reasonable values. *Id.* at 24-25. TASC used the rate impact measure (RIM) and total resource cost (TRC) tests to determine that there is currently no significant cost-shift occurring to non-DG customers, and TASC maintained that, in the long-run, non-DG customers would realize net benefits from DG investment and deployment. *Id.* at iii, 44.

TASC suggested that the Commission seek to align rates with costs incurred by the utilities through TOU rates or through a minimum bill provision, as long as the rates allow customers to have a choice to adopt DG. *Id.* at iv, 35-36. In addition, TASC invited the Commission to consider removing non-bypassable charges such as the system benefits charge and electricity consumption tax from the credit rate applicable to net metering exports. *Id.* at iv, 36. TASC argued that the Commission should not implement fixed charges, demand charges, DG-specific rate designs, or a separate rate class for DG customers. *Id.* at iv.

EFCA relied on and supported the DG benefit-cost study performed by TASC witness Beach. Exh. 21 at 2-3. EFCA claimed that the current net metering tariff does not cause unjust or unreasonable cost-shifting, and argued that the utilities “have not provided sufficient evidence that a cost-shift exists, or if one does, that it is unjust and unreasonable.” *Id.* at 3. EFCA emphasized the need for further data collection, information sharing, and transparency to enable evaluation of new DG benefit-cost study methodologies, the respective benefits and costs of potential new net metering programs, non-wires alternatives to be considered through utility distribution system planning processes, and alternative or pilot rate designs and billing mechanisms. *Id.* at 5-11. EFCA supported pilot programs to determine the potential benefits of DG installations in specific locations, as a non-wires alternative, and the use of TOU rates with shorter peak periods for residential customers. *Id.* at 16.

4. New Hampshire Sustainable Energy Association

NHSEA is a statewide advocate for renewable energy development and sustainable energy initiatives. NHSEA claimed that “the net benefits [of DG] to all ratepayers are significant and that there is no demonstrable [or] unreasonable cost-shifting presently attributable to net metering.” Exh. 28 at 12. NHSEA proposed a net metering tariff that would be implemented once the levels of DG penetration reach the current 100 MW cap; at that point, the current tariff as applied to residential systems under 100 kW should only be changed so that the credit provided for exported energy no longer includes the system benefits charge, stranded cost recovery charge, and electricity consumption tax. *Id.* NHSEA recommended that the Commission consider re-evaluating the appropriate net metering reimbursement rate when aggregate DG penetration increases in increments of 5 percent. *Id.* At that point, NHSEA further recommended removal of the 100 kW limit on retail rate net metering in favor of a structure based on either, “well-defined project sizes where economies of scale shift, or on a customer-class basis,” or at least an increase in the 100 kW system size limit to 250 kW. *Id.* at 12-13. NHSEA also proposed that, for residential net-metered customers, the Commission consider an optional adder that would include a REC value through an aggregator purchase program offered by the utilities. *Id.* at 13.

For commercial customers with systems larger than 100 kW, NHSEA proposed net metering compensation beyond the default energy supply charge, including several potential adders such as a locational benefits adder for helping to relieve congestion, a directional benefits adder based on system directional orientation (e.g., west-facing solar arrays), an environmental benefits adder, a municipal or other public benefits adder, a peak demand TOU adder, an adder for encouraging development of otherwise unusable or already developed land for DG, and an

adder for storage or other ancillary services such as voltage regulation. *Id.* at 13-14. NHSEA also recommended that the maximum project size of 1 MW be increased. *Id.* at 11.

According to NHSEA, any net metering tariff applicable to an interconnected customer-generator should be set for 25 years, with a step-down mechanism in place so that, as DG penetration levels increase, the compensation rates decline only for new customer-generators. *Id.* at 15. NHSEA opposed any cap or other statewide limitation on DG capacity, but if a cap were determined to be appropriate, it should be set based on robust technical data and be similar to policy practices in other states in the region. *Id.* at 11.

In rebuttal testimony, NHSEA witnesses criticized Unitil and Eversource for the lack of supporting data and the unwarranted assumptions underlying their proposals, as well as their failure to analyze the potential effects of their proposals on DG customers. Exhs. 48, 52, and 53. NHSEA also criticized the utility proposals for the inefficient price signals they would provide to DG customers. Exh. 48 at 29-30; Exh. 53 at 17-19. NHSEA witnesses Phelps and Bride asserted that the utilities had not demonstrated that unreasonable cost-shifting is occurring. Exh. 48 at 38; Exh. 52 at 11; Exh. 53 at 8.

5. Conservation Law Foundation and Acadia Center

CLF's witness discouraged adoption of policies that would deter additional deployments, as "experience in other states suggests that there is no obvious rationale for major changes in the near term." Exh. 22 at 7. According to CLF, there is no unjust and unreasonable cost-shifting occurring and, if anything, the energy flowing back to the grid affects utility costs in a similar manner as other types of load reduction, and the DG customer therefore should be compensated for providing renewable energy to the system. *Id.* at 3-4. CLF claimed that all customers benefit from "the avoided T&D upgrades, reduced wear and tear, the reduction in percentage line losses,

reduced market prices, reduced environmental effects, and reduced cost of environmental compliance.” *Id.* at 9. According to CLF, at the current low DG penetration levels, very little cost is incurred on the utility system. *Id.* at 21. On the other hand, CLF acknowledged that the full effects of net metering are not yet clear, and it is possible that it does not reduce costs for other customers. *Id.* at 4. Instead of proposing a new tariff, CLF advised the Commission to review ratemaking options by recognizing all of the system benefits and costs, ensuring there is simplicity and consumer understanding, and making sure that any rate design is effective in encouraging efficient customer choices. *Id.* at 8. According to CLF, the Commission should focus on a simple and straightforward net metering tariff that can change as DG penetration levels increase, and it should monitor DG installed capacity as a percentage of utility peak load and set threshold triggers that would initiate further review at 5 and 10 percent thresholds of utility peak load. *Id.* at 33-34. CLF recommended pilot programs like the City of Lebanon’s proposed real-time energy pricing pilot or a locational pilot where targeted DG could be used to defer or avoid specific major system or localized distribution projects. *Id.* at 35-36. In rebuttal testimony, CLF witness Chernick emphasized the relative peak coincidence of solar DG output and its beneficial effects on T&D system cost avoidance. Exh. 59.

Acadia Center filed only rebuttal testimony, in which it recommended the adoption of monetary crediting and separate structural reforms for new projects on a gradual basis that is simple and consistent with public policy objectives, while allowing existing net-metered customers to be grandfathered. Exh. 57 at 12. According to Acadia Center, the net metering tariff should align credits with the long-run value that DG provides, which includes avoided T&D and generation costs, as well as environmental and health benefits. *Id.* at 13.

Acadia Center opposed putting net metering customers in separate rate classes; instead, any changes should be effected through riders that determine net export credit values. *Id.*

Acadia Center also opposed separate demand charges for DG customers because such charges would treat DG customers differently, would not satisfy understandability and bill management principles in the short-term, and, when based on individual customer peaks, would not satisfy cost causation principles. *Id.* at 21. According to Acadia Center, DG customer demand charges could be considered in the long-run if such charges were based on coincidence with local peaks and were designed to allow customer response in a timely way. *Id.* Acadia Center asserted that minimum bills are similar to demand charges in terms of impacts on customer response and effects on low income customers. *Id.* at 22.

Acadia Center proposed that volumetric crediting be changed to monetary crediting on a per-kWh basis, which would permit time-varying rates to be used for crediting. *Id.* at 14.

According to Acadia Center, time-varying rates would need to be aligned with the hours that cause costs, and netting of credits should be based on the applicable time period. *Id.* at 23.

Acadia Center did not propose that residential DG customers be switched to time-varying rates, except through a limited pilot program. *Id.* According to Acadia Center, time-varying rates for commercial and industrial (C&I) customers would be reasonable. *Id.* at 24.

Acadia Center proposed that small DG projects maintain the current net metering structure with the exclusion of several elements, such as the system benefits charge, stranded cost recovery charge, and electricity consumption tax, from the full retail rate, and that net metering compensation should be through monetary crediting rather than kWh banking. *Id.* at 18-19. Acadia Center proposed that projects greater than 100 kW be credited in accordance with its “Next Generation Solar Framework for New Hampshire.” *Id.* at 15. It also supported the

TASC benefit-cost study analysis as a means of determining the long-run costs and benefits of DG. *Id.* at 16.

Acadia Center argued that no caps or limitations should apply to an alternative net metering tariff. *Id.* at 14. Acadia Center supported the thresholds proposed by CLF and NHSEA for the Commission to revisit the determined net metering compensation for residential customers. *Id.* at 19-20.

6. Office of the Consumer Advocate

The OCA proposed a framework intended to lead to what the OCA argued would be a positive outcome for all parties within a five-year period. Exh. 17 at 8. The OCA's preliminary analysis of the benefits of solar DG indicated potential benefits ranging from 13-15¢ per kWh, which does not include different types of societal benefits that are hard to quantify. *Id.* The OCA's witness acknowledged that cost-shifting or cross-subsidization is likely in rate making, and should be minimized to the extent possible; he therefore proposed an optional DG TOU rate program for residential customers and a "Fixed Solar Credit Rate" program, which would be open to all customers, including non-residential and community solar subscribers. *Id.* at 16. The proposed TOU rate would be based on volumetric usage that would send more accurate price signals to DG customers and would have an on-peak period aligned with actual utility system peak load hours in order to better align solar customer's exports to the grid with real-time market pricing. *Id.* at 17.

The OCA's proposed DG TOU option would include the following rate components: a customer charge, energy supply charge, TOU delivery charge, export charge, partial non-bypassable transmission charge, and other non-bypassable charges. *Id.* at 18. According to the OCA, the "Fixed Solar Credit Rate" option is designed to compensate DG customers for excess

energy produced by their systems and allow for continued DG growth in New Hampshire, “by providing increased certainty and sufficient compensation to DG customers and installers, while also capturing value and cost savings for non-participating utility customers over time.” *Id.* at 33. To control growth of the program, the OCA proposed that this option initially be limited to 200 MW. *Id.* at 35-36. The net metering credit rate for smaller-scale DG systems would be determined through a capacity-based tranche step-down mechanism prescribed in advance, while the credit rate for larger-scale DG systems would be determined through an auction mechanism. *Id.* at 36-37. Community solar projects would be eligible for the “Fixed Solar Credit Rate” option and would have rates similar to residential and commercial customers, depending on system size, with potential credit rate adders such as an environmental benefits adder and a low and moderate income adder. *Id.* at 45; Exh. 18 at Bates 68-76.

The OCA asserted also that cost-shifting would no longer occur if DG customers were able to exchange their RECs with their interconnecting utilities. Exh. 17 at 9, 31.

7. City of Lebanon

City of Lebanon witness Below focused the majority of his testimony on a recommendation for an alternative net metering rate structure based on real-time energy pricing. Mr. Below proposed a real-time pricing (RTP) net metering tariff offered on an opt-in basis, under which, during each real-time interval, electricity exported to the grid would be credited to participating DG customers at ISO-NE’s New Hampshire load zone real-time LMPs, together with generation related ancillary services, as adjusted for avoided line losses. Exh. 25 at 7. During times when a DG customer imports power, the customer would be charged at the same real-time LMPs, as well as a billing and overhead mark-up cost. *Id.* ISO-NE Forward Capacity Market (FCM) prices would be charged or credited as avoided. *Id.* The City of Lebanon

proposed that transmission charges be charged or credited depending on a DG customer's load during the monthly coincident peak (CP). *Id.* Mr. Below also proposed that distribution rates be modified on a revenue-neutral basis, with demand charges based on the customer's share of CP; that volumetric distribution rates be modified on a revenue-neutral basis so costs would be recovered during the hours when system peaks are likely to occur; and that the distribution revenue requirement be decoupled from a net changed volumetric load compared to forecasted load. *Id.*

Because the solution proposed by the City of Lebanon cannot readily be implemented within a near-term time period, Mr. Below proposed a long-term (*i.e.*, through 2040) RTP net metering pilot program that would be a "work-around" to current utility metering and billing limitations. *Id.* at 8. The pilot program contemplated by the City would use the municipal aggregation statute, RSA 53-E, and involve the services of a competitive electric power supplier. *Id.* The City of Lebanon concluded that a volumetric credit should continue to be allowed to be carried forward for default service and transmission charges, but not for distribution services. *Id.* at 9.

8. Staff

Staff filed only rebuttal testimony, in which its witness, Stan Faryniarz of Daymark Energy Advisors, reviewed the parties' positions as stated in their direct testimony. Exh. 65 at 6. He analyzed issues regarding the respective costs and benefits of DG systems in the net metering context, and critiqued parties' positions regarding those costs and benefits, with a particular focus on the long-term benefit-cost study performed by TASC witness Beach. *Id.* at 32-38. He also concluded that, given the lack of relevant data and low DG penetration levels in New

Hampshire, it had not been demonstrated that DG electricity exports resulted in significant costs or benefits to the utility distribution system. *Id.* at 44.

Mr. Faryniarz suggested that a well-designed and properly conducted long-term avoided cost study using marginal concepts and incorporating both TRC benefit-cost test and RIM test criteria “should prove useful in informing DG net metering program designs to be considered and approved by the Commission,” and that the use of that suggested approach “should not preclude consideration of any demonstrable and quantifiable net benefits associated with relevant externalities, provided that the potential for double-counting is adequately mitigated.”

Id. at 37-38, 129.

With respect to cost-shifting, Mr. Faryniarz concluded that, in view of the current low levels of DG penetration, “an unjust and unreasonable level of cost-shifting for power supply costs and utility delivery service is not likely to occur within the near-term.” *Id.* at 78. He also asserted there is no current justification for segregating DG customers into a separate rate class. *Id.* at 83. He maintained that demand charges for residential customers with DG should not be implemented unless the charges are based on coincident peak or are time-differentiated. *Id.* at 86. According to Mr. Faryniarz, implementation of residential customer demand charges at this time is not recommended, “based on issues regarding the installation and cost of required metering capable of recording demands over all hours of the billing cycle, customer acceptance and understanding, ability to monitor and control electricity bills, and the potential for rate shock and dislocation.” *Id.*

Staff expressed the view that, in the longer term, time-differentiated rate designs for net metering tariffs applicable to DG customers, such as TOU rates or RTP models, may hold promise and should be considered by the Commission. *Id.* at 89. In the nearer term, however,

Staff recommended that, for DG systems with capacity equal to or less than 100 kW, the applicable net metering credit for exported energy continue to be the utility's full retail rate with the exception of non-bypassable charges and assessments such as the systems benefits charge, stranded cost recovery charge, storm recovery surcharges, and state electricity consumption tax. For larger size systems with capacity greater than 100 kW up to 1 MW, the applicable credit for exported energy should continue to be the utility's default service rate only. *Id.* at 94-95. Staff recommended that this near-term period alternative net metering tariff be in effect until the adoption of a new alternative tariff, which would be developed through a new Commission proceeding to be initiated following the first to occur of certain specified "trigger" events. *Id.* at 109.

Staff further recommended that DG customers not be put into a separate rate class until sufficient, actual New Hampshire DG customer data has been presented to show that these customers impose significantly different costs on the system than other customers in the same rate class. *Id.* at 131. Staff also recommended that the Commission consider demand charges for residential DG customers only if and when (a) they can be assessed on a TOU or coincident peak basis, (b) residential customers can be sufficiently educated regarding their operation and effect, and (c) metering and other technology improvements are installed to provide customers with real-time information regarding their kWh usage and kW demands and meaningful opportunities to control such usage and demand. *Id.* at 131-132.

Staff recommended that the Commission consider approving tariff provisions that would maintain a particular net metering rate structure for a defined period of time for those DG customers who secure a net metering capacity allocation within a specified time period before any future net metering tariff changes are implemented. *Id.* at 132. According to Staff, the

period for such “grandfathering” could be based on the useful life of DG system components such as 10, 15, or 25 years, or could be equivalent to a typical financing or lease period for such systems. *Id.*

Staff strongly recommended that any near-term period net metering tariff incorporate the same rate structures for all three regulated utilities to allow for common implementation processes, as well as ease of program comparison, pilot program administration, and implementation of other potentially affected rate elements. *Id.* Staff also supported approval of a uniform mechanism for the utilities to recover lost revenue resulting from net metering, such as that described in the settlement agreement with Unitil filed in Docket DE 15-147, based on reasonable estimated revenue losses unless and until the utilities are able to measure and calculate actual lost revenues through improved metering capabilities. *Id.* at 132-133.

Staff recommended that the Commission direct the regulated utilities to develop and implement two separate net metering pilot programs, each for a limited number of residential and/or small commercial customers on an opt-in basis: (1) a TOU or other time-differentiated rate pilot program, and (2) a locational DG siting pilot program targeted to segments of the utility distribution system on which DG installations would be expected to have a demonstrably positive impact. *Id.* at 133. According to Staff, each of those pilot programs would provide the opportunity for collection and publication of more comprehensive and detailed data regarding DG system costs and benefits, system planning, DG customer behavior, and the effects of alternative net metering rate structures. *Id.*

Staff further recommended that the Commission direct the regulated utilities to collect and make available specific and detailed data over the next several years, as such data would be useful in informing future rate designs for alternative net metering tariff structures. *Id.* at 134.

According to Staff, the data should include at least a representative sample of DG customer load profiles, highlighting both consumption and DG output, and increases or decreases in DG customer energy usage and demand as well as energy imports and exports from DG systems. *Id.* The data should also include more detailed and specific information regarding operation of the utility distribution circuits, substations, and other system components, and the actual and potential effects of DG installations on those circuits, substations, and other components. *Id.* Staff noted that much of the data proposed to be collected would also be relevant in the initiatives under review in connection with the Commission's investigation into grid modernization, Docket IR 15-296 (Grid Mod Docket). *Id.* Staff recommended that working groups, including the utilities, other parties, and Staff, be convened to develop detailed plans and timelines for further data collection, any required metering and equipment procurement and installation, and the production and dissemination of the additional data collected. *Id.*

B. Settlements

The two Settlements have many common elements as well as a number of important differences. We will summarize the common elements covered by the Settlements, and then describe the major points in each Settlement that represent unresolved differences.

1. Common Elements of Settlements

Both of the Settlements provide for adoption of an alternative net metering tariff to be in effect during a period of time during which data would be collected, pilot programs would be implemented, and studies would be conducted. Exh. 1 at 3-13; Exh. 5 at 3-11. The basic design and structure of net metering would be continued during the near-term period for both small customer-generators (i.e., DG systems of 100 kW or less) and for large customer-generators (i.e., DG systems greater than 100 kW but not greater than 1,000 kW), except that monetary crediting

for electricity export compensation would replace kWh banking. Exh. 1 at 4-7; Exh. 5 at 3-7. Customer-generators would have the opportunity to receive a cash payment for any accumulated excess monetary credits when they move or on an annual basis if their credit balance exceeds \$100. Exh. 1 at 7; Exh. 5 at 6-7.

Net-metered customer-generators would have bi-directional meters that record in separate channels the quantities of electric imports from the grid and electric exports to the grid on a monthly basis. Exh. 1 at 4; Exh. 5 at 10. Customer-generators would pay certain non-bypassable charges such as the system benefits charge, stranded cost recovery charge, storm recovery surcharges, and the state electricity consumption tax based on the full amount of their electricity imports without any netting of exports. Exh. 1 at 4; Exh. 5 at 4. For their exports, customer-generators would be credited at the utility's default service energy charge and for 100 percent of transmission charges assessed on a kWh basis. Exh. 1 at 4; Exh. 5 at 4-5. There would be no change in customer charges or application fees, unless a utility makes a future filing for such a change based on demonstrated incremental costs. Exh. 1 at 12; Exh. 5 at 3.

Large customer-generators would continue to receive export credits based only on the utility default service energy charge, but with monetary crediting rather than kWh banking. Exh. 1 at 4, 7; Exh. 5 at 4, 6-7. Large customer-generators would be eligible for the new alternative net metering tariff if they consume at least 20 percent of their DG system electric production on-site and behind-the-meter; if their on-site consumption is less than that threshold, then they would have to be registered as a group host under RSA 362-A:9, XIV. Exh. 2 at 2; Exh. 5 at 5. Large DG system owners that meet the on-site consumption threshold would have the opportunity to switch to the new alternative net metering tariff. *Id.*

Customer-generators that receive a net metering capacity allocation while the new alternative net metering tariff is in effect would be “grandfathered” at the applicable net metering design and structure then in effect, through December 31, 2040, consistent with the current statutory provisions. Exh. 1 at 12-13; Exh. 5 at 7-8. Changes in underlying prevailing rates and rate designs, however, would continue to apply to DG customers in the same manner as to all other customers in the same rate class. Exh. 2 at 2; Exh. 5 at 3.

The utilities would provide services intended to facilitate participation in the REC markets by small DG system owners. Exh. 1 at 13; Exh. 5 at 6. Those services would include the utilities’ agreement to work with parties on the solicitation of a third party REC administrator and/or aggregator and the utilities’ facilitation of REC program promotion and customer education. Exh. 2 at 3; Exh. 5 at 6. Customer-generators would continue to own the RECs they produce and the utilities would not be obligated to purchase those RECs. Exh. 1 at 13; Exh. 5 at 6.

The utilities would have the opportunity to recover lost revenues attributable to customer net metering pursuant to the mechanism and process approved by the Commission for Unitil by Order No. 25,991 (February 21, 2017) issued in Docket DE 15-147. Exh. 2 at 2; Exh. 5 at 4. The utilities also would be permitted to recover the prudently incurred costs of required metering upgrades, study expenses, and pilot program implementation. Exh. 1 at 18; Exh. 5 at 9-11.

With respect to data collection and studies, the Commission would perform a value of DER study, and review the level of appropriate compensation for avoided ISO-NE charges for Regional Network Service (RNS) and Local Network Service (LNS). Exh. 1 at 3; Exh. 2 at 4; Exh. 5 at 8. Each of the Settlements provides for design and implementation of two types of pilot programs: (1) a low and moderate community solar participation pilot that would use

monetary bill credits to make the benefits of solar available to customers whose financial circumstances would otherwise not allow them to participate in a net-metered project, and (2) a TOU pilot or pilots based on time-varying rates for DG customer-generators as well as other residential customers. Exh. 1 at 15-16; Exh. 5 at 9. The pilot programs would be designed through a collaborative stakeholder process involving a task force to be convened and overseen by the Commission. Exh. 1 at 13; Exh. 5 at 9.

2. Utility and Consumer Coalition Settlement

The UCC Settlement would provide no net metering credit against utility distribution charges for electricity exports from DG systems. Exh. 5 at 4; Exh. 6 at 5. The UCC Settlement also would eliminate netting of kWh produced by small customer-generators during the course of a monthly billing cycle, instead charging DG customers the full retail rate for all electricity imports and crediting DG customers at the approved credit amount for all electricity exports, both as recorded in the separate channels of the utility bi-directional meters. *Id.* at 4. This approach to metering and billing of net-metered customer-generators is referred to as “instantaneous netting” by supporters of the EFC Settlement. Transcript of Hearing (Tr.) 3/27/17 A.M. at 54, 114. Under the UCC Settlement, the new alternative net metering tariff start date would be July 1, 2017, meaning that any customers with DG projects queued after that date would be subject to the new tariff provisions once the utility is capable of implementing those provisions. Exh. 5 at 2-3.

The UCC Settlement provides that DG customers taking energy service from a third party competitive electric power supplier (CEPS) would receive credit for any exports on the energy service portion of their bills at the avoided cost rates as calculated annually by the Commission under Puc 903.02(i). *Id.* at 4-5. The total of all kWh exports that are credited at avoided cost

rates or at default service rates would be applied to reduce the utility's ISO-NE wholesale load obligation that is allocated to all suppliers, except for projects registered with ISO-NE as settlement-only generators. *Id.* at 7.

The UCC Settlement provides that the default service portion of the credit for exported energy and any avoided cost credits for exported energy provided to customers on competitive supply would be recovered via reconciliation through the default service charge. *Id.* The transmission service portion of the credit provided to customers for exported energy would be recovered through the utility's annual transmission rate reconciliation proceedings. *Id.*

With respect to DG customer REC market participation, the UCC Settlement provides that the utilities would serve as independent monitors for customer-generators who want the utilities to monitor their electricity output and report the output to the New England Power Pool Generation Information System (NEPOOL-GIS). *Id.* at 6. The UCC Settlement would provide customer-generators the option to request installation of a revenue grade production meter, to be owned by the utility and at no cost to the customer, which would provide customers with the data necessary to participate in the REC market. *Id.* at 6, 10. If a DG customer installs its own production meter, then the customer would be responsible for its own RECs and the utility would estimate production from the system for lost revenue purposes. *Id.* at 11. The utilities would have the opportunity to file on an annual basis for recovery of costs associated with meters installed and related data management. *Id.* at 11.

The UCC Settlement would require the utilities to provide data, where available, on annual loads for net-metered accounts for one or more years before the customers interconnect their net metered systems along with annual average loads for comparable time periods, before and after implementation of net metering, for customers who did not adopt net metering. This

would be “so that the percent change in annual load for customers, by rate class, who did and did not adopt net metering, can be compared for comparable time periods.” *Id.* at 9.

Under the UCC Settlement, a locational value study similar to the “*Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods*” performed in 2016 by Nexant, Inc. for Central Hudson Gas & Electric (the Nexant Study), would be performed under supervision of the Commission. *Id.* at 8; Exh. 43 at 19-20. The UCC Settlement would require the Commission to conduct a value of DER study, based on real-time market prices and distribution system needs, in which:

- (1) different DER resources (or combinations thereof) at various levels of capacity value are considered;
- (2) valuation is based as closely as possible on real-time prices and near term marginal costs, with no long-term projections or forecasts to be considered in the study;
- (3) actual costs to installers and customers for implementing DER resources in New Hampshire are considered; and
- (4) there are opportunities for public comment prior to the study being conducted.

Exh. 5 at 8. The UCC Settlement proposes that large DG projects would have the opportunity to participate in “an opt-in pilot program ... run to review the feasibility of providing transmission credits based on actual avoided marginal costs following completion of a study relating to RNS and LNS costs.” *Id.* at 10.

Unlike the EFC Settlement described below, the UCC Settlement does not provide for a “Phase 2” alternative net metering tariff to be adopted and implemented at the end of the near-term tariff period. Instead, the UCC Settlement provides that, following the pilot programs and data collection provided for, the UCC Settlement parties “agree to petition the Commission to

open a proceeding to review results and information generated by those efforts so that they can inform future distributed energy resource tariffs and rate design.” *Id.*

3. Energy Future Coalition Settlement

The EFC Settlement would provide for a DG system electricity export net metering credit against utility kWh distribution charges equal to 75 percent of those charges from the start date through December 31, 2018, and then reducing to 50 percent of those charges from January 1, 2019, until January 1, 2021. Exh. 1 at 4. The EFC Settlement would continue monthly netting of small customer-generator DG system kWh imports and exports, rather than changing to “instantaneous netting” during the “Phase 1” tariff period. *Id.* at 4-7. Under the EFC Settlement, the new alternative net metering tariff start date would be September 1, 2017, meaning that any customers with DG projects queued after that date would be subject to the new tariff provisions once the utility is capable of implementing those provisions. *Id.* at 4, 9-10.

The EFC proposed that large customer-generators have the option to receive a transmission rate credit based on their actual avoidance through load reduction of marginal RNS and LNS transmission charges assessed by ISO-NE. Exh. 2 at 3.

Under the EFC Settlement, the utilities would work with customers, aggregators, and other relevant third parties to better facilitate the creation of RECs by customer-generators, and the “utilities may choose to purchase RECs directly from a customer for a fixed fee.” Exh. 1 at 13. The EFC Settlement would not require DG system customer-generators to have revenue-grade production meters, whether owned by the utility or otherwise. Exh. 2 at 5.

With respect to studies to be performed, the EFC Settlement would require Eversource to conduct a marginal cost-of-service study prior to performance of the value of DER study. *Id.* at 4. The independent value of DER study would be sponsored by the Commission and

completed during 2020; it would serve as the basis for valuing and crediting exports from DER in the future. Exh. 1 at 3. In particular, the value of DER study would determine the distribution charge export credit value for Phase 2 beginning on January 1, 2021. Exh. 2 at 3. Under the EFC Settlement, the value of DER study would be updated every three years and would 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, according to the EFC Settlement. Exh. 1 at 15.

In addition to the proposed low and moderate income and TOU pilot programs, the EFC Settlement proposes two other pilot programs: (1) an optional “Smart Energy Home Rate” pilot intended to test rate designs such as RTP, critical peak pricing, demand charges, or other structures that enable customers to adopt a variety of technologies and behaviors to manage their electricity consumption, and (2) a “non-wire alternative” pilot intended to test the concept of deploying DER to identified locations where they may replace or defer traditional utility T&D investments, such as new lines and substations, on a cost-effective basis, using incentive mechanisms that “drive investments to specific areas on the grid.” *Id.* at 16-17.

The EFC Settlement proposes that the “Phase 1” tariff design be in effect for a defined period of time, to be followed by development and implementation of a “Phase 2” alternative net metering tariff by January 1, 2021. *Id.* at 4-5; Exh. 2 at 3, 5. The Phase 2 net metering tariff design would be similar to the Phase 1 design, except that the amount of the distribution charge credit for net exported electricity would be based on the results of the value of DER study. Exh. 1 at 10, 17-18; Exh. 2 at 3, 5. The EFC Settlement also would require the utilities to develop optional TOU and “Smart Energy Home” rates that DER customers could sign up for

beginning on January 1, 2021. Exh. 2 at 5. The EFC Settlement provides that Phase 2 customers would be “grandfathered” for a period of 20 years. Exh. 1 at 12; Exh. 2 at 4.

C. Parties’ Hearing Positions

We will briefly summarize the key positions of the parties expressed during the hearings and through their post-hearing written statements and briefs.

1. EFC Settlement Parties

Much of the testimony at hearing of witnesses supporting the EFC Settlement focused on the difference between instantaneous netting and monthly netting, the amount of the distribution charge credit for electricity exports, and the process and timeline for transitioning from Phase 1 to Phase 2.

Instantaneous netting was criticized because it “eliminates the very concept of net metering as it was created – that was created to encourage and enable customers who installed generation primarily to offset their use with distributed generation.” Tr. 3/27/17 A.M. at 54. The elimination of monthly netting in combination with substantial reductions in compensation for DG system energy exports would represent “a huge step backwards for New Hampshire.” *Id.* at 55. Current and prospective DG customers understand monthly netting, and the value of net metering can be easily modeled and explained to them under this approach; by contrast, the potential effects of instantaneous netting are difficult to understand and virtually impossible to model due to the unavailability of time-differentiated customer load data. *Id.* at 56-57. According to EFC witness Mueller, instantaneous netting would send the wrong signal to DG customers because it would create an incentive for those customers to self-consume as much electricity as possible at the time of day when their production is the highest, which is also likely to be a time when the grid is most in need of excess power from DG systems. *Id.* at 57.

With respect to the distribution component of the net metering export credit, EFC witness Rabago testified that the UCC proposal to value that credit component at zero was undercut by the lack of credible evidence of cost-shifting resulting from net metering and improper failure to recognize the benefits provided by DG in avoiding utility system distribution costs over the 25 or more years that a DG system will likely operate. *Id.* at 52. According to Mr. Rabago, because DG systems “operate in a mode of interconnection to the distribution grid, zero is the only value of distribution costs or benefits that we know is absolutely wrong.” *Id.* He cited Mr. Beach’s testimony as showing a value at least equal to 50 percent of distribution charges. *Id.* He further asserted that assigning a zero value for the distribution credit effectively implies there is no utility distribution expansion that could be delayed or avoided by strategically deployed DER, a position that is “not only highly improbable, but out of synch with work that is going on around the nation, and with the kind of analysis of costs and benefits envisioned in HB 1116.” *Id.* at 52-53. According to Mr. Rabago, it is not credible to propose a rate for net metering with no credit for avoided distribution system costs. *Id.* at 53.

EFC witness Hawes of Acadia Center confirmed that, with reference to the proposed distribution credit reduction and the use of instantaneous netting, “a 50 percent cut in distribution applied with monthly netting is a small amount whereas a 50 percent cut in the distribution part of the export credit applied instantaneously is a much larger amount.” Tr. 3/29/17 A.M. at 95.

EFC witness Epsen described the transitional approach represented by the two distinct phases provided for in the EFC Settlement: Phase 1 would consist of near-term changes to lower costs and immediate studies managed by the Commission to gather essential data with all deliberate speed, and then Phase 2 would require the Commission to use that data to create better price signals to inform consumption decisions and maximize the value of DER investments to

the grid. Tr. 3/27/17 A.M. at 36. EFC witness Bean emphasized the importance of the phased transition to a Phase 2 alternative net metering tariff based on an independent Value of DER study, stating these are “critical parts of [the EFC] plan and the reason [EFC has] proposed reducing the distribution component in the near-term in exchange for more long-term certainty and predictability.” *Id.* at 44. According to Mr. Bean, the EFC Settlement would reduce the value of DG system exports materially in return for a transition to Phase 2 based on the completion of studies and “the collection of data we wish we would have had in this proceeding.” *Id.* at 48. He also confirmed the EFC’s position that the primary or perhaps sole purpose of the value of DER study would be to determine the updated distribution credit to be applied in Phase 2, and that the study scope would be necessarily bounded by that limited purpose. Tr. 3/27/17 P.M. at 115. Mr. Beach further clarified that the value of DER study “would definitely be more constrained in its focus just on distribution,” although “in looking at distribution, it would be much more detailed.” *Id.* at 116.

According to EFC witness Mueller, the EFC Settlement emphasizes the critical importance of certainty, understandability for the customer, and gradualism in order to avoid a rate shock. Tr. 3/27/17 A.M. at 98. EFC witness Phelps expressed the view that the drastic reductions in the UCC Settlement “will be seen nationally as extreme and will discourage the competitive market of DER in New Hampshire, contrary to the purpose statement of [HB 1116] and what is in the best interest of New Hampshire consumers and its economy.” *Id.* at 59-60.

In their post-hearing brief (EFC Brief), the EFC settling parties stated a number of reasons in favor of continued monthly netting instead of instantaneous netting, including the price signal effect, the lack of relevant customer-specific load data from the utilities, the adverse financial impact of instantaneous netting, the fact that Eversource and Unitil affiliates in other

New England states use monthly netting, the claimed illegality of the change for customers taking competitive electric supply, and potential adverse consequences under PURPA and federal income tax law. EFC Brief at 7-14. With respect to the value of the distribution charge credit, the EFC settling parties argued that the UCC Settlement proposal for zero valuation is unsupported in the factual record and, in the absence of data to provide an accurate representation of current and anticipated distribution benefits of DER systems, only the EFC Settlement provides a moderate, incremental shift toward a future state in which distribution values are more readily quantifiable and realizable. *Id.* at 14-17.

The EFC settling parties further asserted that the start date for the new alternative net metering tariff should be no sooner than September 1, 2017. Ideally the new tariff would become effective six months after the Order is issued, “so as to provide the lead-time necessary for DER providers, customers, and utilities to adapt to the new rules.” *Id.* at 17-18. They also urged the Commission to adopt their proposed data collection and study scope and timing recommendations, as well as the four specific pilot programs they proposed, and to reject the pilot programs and data collection and study proposals contained in the UCC Settlement. *Id.* at 18-24. The EFC settling parties also requested that the Commission “define a clear trajectory to the future” by approving their two-phase transition proposal, citing as an example a recent order issued by the New York Public Service Commission with respect to the transition of net metering to a value of DER model. *Id.* at 24-29. They further urged the Commission to specifically define and limit the excluded non-bypassable charges to which net-metered customers would be subject under the new alternative tariff, rather than leaving those charges open to future and unknown adjustments as provided in the UCC Settlement, so as to provide greater uncertainty to future DG system owners. *Id.* at 29-30.

In conclusion, the EFC settling parties asked the Commission to approve their settlement proposal after finding that the EFC Settlement would “reduce financial compensation to customer-generators for their locally produced renewable power materially while minimizing unnecessary and unjustified disruptions to the still-nascent New Hampshire DER market and [also provide] a specific, well-designed path to availability of the data necessary for and creation of accurate net metering rates.” *Id.* at 30.

2. UCC Settlement Parties

Witnesses supporting the UCC Settlement emphasized that theirs is a compromise agreement to be implemented in the near term and for a limited period of time. Tr. 3/28/17 A.M. at 35. Much of the testimony at hearing of witnesses supporting the UCC Settlement focused on the difference between instantaneous netting and monthly netting and the amount of the distribution charge credit for electricity exports.

UCC witness Labrecque questioned the EFC’s argument that prospective DG customers would have difficulty understanding, and solar installers and developers would find it challenging to explain, how instantaneous netting works and the potential impacts of that metering and billing model. *Id.* at 46-47. He asserted that these are “highly sophisticated technology companies that are fully capable of modeling,” and should welcome the opportunity to build stronger relationships with and deeper understandings of their customers. *Id.* UCC witness Davis maintained that the UCC Settlement provides “a simple, transparent and easy-to-understand alternative to net metering,” that would “move toward equitable cost recovery and rate structures.” *Id.* at 48. He emphasized the “transparency particularly afforded by separately measuring [electricity] imports and exports.” *Id.* at 49.

UCC witness Meissner stated that instantaneous netting “is far preferable, from the standpoint of distribution planning,” because the utilities “would prefer the customers right-size their generation equipment and then use as much of their own production as possible on site rather than exporting uncontrolled, intermittent and non-dispatchable generation onto the distribution system.” *Id.* at 52-53. According to Mr. Meissner, monthly netting sends no price signals, provides no incentive for changes in customer behavior, and may even serve as a disincentive for implementation of on-site energy storage. *Id.* at 53. With respect to the distribution charge credit amount, Mr. Meissner stated extensive data exists in the record indicating there is “little or no short-term benefit to the distribution system” from DG resources, and, even over the longer term, there is “very minimal opportunity for solar DER to offset future investments by the electric utilities.” *Id.* at 54.

UCC witness Brown asserted that the UCC Settlement changes are “highly incremental” and “very modest,” in contrast to “many other states where the changes are far more significant than they are here.” *Id.* at 57. According to Mr. Brown, these positive changes include the adoption of “instantaneous netting,” which represents “a modest but incremental movement towards the kind of time-sensitive pricing that the solar people claim they support,” and provides more meaningful and transparent price signals. *Id.* at 59. He also cited the UCC Settlement changes as a positive “step in the direction of allowing ... a greater share of the declining costs of solar panels to be passed on to customers.” *Id.* at 60. Mr. Brown further maintained that the changes would “encourage more customers to be self-sufficient and effectively help to shift load off peak,” as well as representing a “modest step ... towards market pricing” with the goal of “trying to get the prices right and send customers the right price signals.” *Id.* at 60-61.

In their Joint Closing Statement (Utilities' Closing Statement), Eversource, Liberty, and Unitil (Utilities) argued that the distribution credit to customer-generators should be set at zero based on the lack of credible evidence in the record that DG actually avoids distribution system expenses, and included a detailed critique of the studies and analyses relied on by EFC witnesses, including TASC witness Beach and CLF witness Chernick. Utilities' Closing Statement at 2-8. The Utilities acknowledged that "some aggregation of DG resources" potentially could eliminate or delay the need for circuit upgrades to accommodate growth in customer peak demand, provided that there were both a need to address demand growth and DG resources that could meet the necessary criteria to address that demand, "including that they provide the level of reliability and predictability required to ensure continued safe and adequate operation of the electric distribution system for all customers at all times." *Id.* at 4. According to the Utilities, there is no evidence in the record that such criteria have been met, and therefore there is no basis to compensate DG resources for any distribution-related costs. *Id.*

With respect to "instantaneous netting" as opposed to "monthly netting," the Utilities asserted that there is no "functional difference" between the two settlement proposals regarding netting of the commodity, transmission, and non-bypassable charge components of the rate, but only regarding the distribution credit and only if that credit is greater than zero and less than 100 percent. *Id.* at 8. The Utilities further argued that monthly netting "would be out of step with New Hampshire law," citing RSA 362-A:9, IV, and also "would result in a reduction that is so small it may hardly be called a change at all." *Id.* at 8-9. According to the Utilities, the changes proposed by the EFC would result in a difference in compensation levels from the current full retail rate net metering of "at most, about four dollars per month." *Id.* at 10. The Utilities claim that change is "so slight that it would be more than offset by nearly any other

factor affecting the customer's home or generation system,” contrasting that slight change with the UCC Settlement that “would result in a change of approximately 14 percent as shown in Exhibit 6, the UCC technical statement.” *Id.*

The Utilities also challenged the EFC witnesses’ contention that it would be impossible to either understand or respond to the price signals sent by instantaneous netting, or to explain to customers how that netting approach would affect the economics of their prospective DG investment. *Id.* at 11-12. According to the Utilities, a number of the EFC parties are “large and sophisticated entities with national reach” that have adapted or will have to adapt to similar netting proposals where they have been implemented elsewhere, but have neither obtained the customer data available or performed the analyses necessary to properly educate their customers about the alternative netting approach. *Id.*

With respect to data collection, studies, and pilot programs, the Utilities maintained that the “broad parameters set out in the UCC [Settlement] provide an appropriate framework around which to build an order relating to those programs.” *Id.* at 13. They claimed that the UCC Settlement identifies an appropriate model for a locational value study that would form the basis for any new study in New Hampshire, and sets out a series of times to be included in an appropriate value of DER study although further adjustments would be needed to that basic framework. *Id.*

NERA filed a closing statement emphasizing the need to avoid unjust and unreasonable cost-shifting under any “well-structured net metering tariff.” NERA Closing Statement at 2. NERA reiterated its position that hourly LMPs would represent the appropriate basis for compensation of DG customer energy exports, while it “recogniz[ed] that balancing the timely implementation of the necessary metering and billing practices requires a transition period to

achieve.” *Id.* at 3-4. According to NERA, it made a significant compromise in joining the UCC Settlement which allows for a tariff that compensates DG customer exports at the default service energy rate. *Id.* at 4. With respect to the distribution charge credit amount, NERA asserted that the EFC witnesses had not quantified any benefit or justified their proposal to set the distribution credit at 75 percent of distribution costs. *Id.* at 5. NERA indicated its belief that the value provided by DG systems to the utility distribution system is “de minimis and is possibly negative,” and therefore the UCC Settlement “best reflects the best assessment of that value considering the lack of quantifiable evidence to the contrary.” *Id.* NERA observed that, under the UCC Settlement, the Commission and the utilities “would expeditiously move to collect the necessary data to better quantify and implement a robust compensation value for the distribution component of the net metering tariff, recognizing that the value may, in fact, be negative.” *Id.* at 6. NERA further argued there was no quantifiable evidence that small DG systems have any material effect, positive or negative, on the electric transmission system, and therefore it had made a significant compromise in joining a settlement that compensates DG for transmission in the near term before more definitive study can be completed. *Id.* at 7. NERA concluded that the UCC Settlement “is the most fair and justifiable solution that minimizes the near term and long term impacts of a new net metering tariff.” *Id.*

CEA filed a closing statement and summation confirming that it had joined the UCC Settlement because “it best achieves the legislative intent codified in HB 1116 by providing *all consumers* with the best opportunities to invest in DG, to achieve affordable rates, to receive fair compensation for investments in DG, and to ensure that all *consumers* are treated equally.” CEA Closing Statement at 2 (emphasis in original). CEA asserted that all consumer representatives, including NERA, OCA, OEP, and CEA, were in support of the UCC Settlement. *Id.* According

to CEA, the UCC Settlement would “ensure the continued deployment of DG” because small DG customers would receive bill credits for energy and transmission that are greater than the price at which utilities typically acquire electricity on the wholesale market. *Id.* at 3. CEA maintained that the proposed zero distribution credit would allow the electric distribution companies to recover more of the cost of serving DG customers, “which prevents cost-shifting and socially regressive incentives – and allows for more re-investment in grid services that nearly every state *consumer* utilizes.” *Id.* at 4 (emphasis in original). CEA further claimed that the UCC Settlement “recognizes the declining costs of solar and mov[es] towards a market sensitive pricing regime.” *Id.* CEA argued that the UCC Settlement is superior to the EFC Settlement because the former “dictates a start date based on a specific day, not based upon phases and milestones that may not be reached or that may become irrelevant based upon time and technological development.” *Id.* CEA maintained that the UCC Settlement proposal for pilots and data collection programs, including low income community solar, TOU, locational value, review of RNS/LNS, and the commencement of a value of DER, provide “the real value of ensuring that New Hampshire's energy market is properly priced moving forward by ensuring solar penetration, a robust electric grid, and fair pricing for all *consumers*.” *Id.* at 6 (emphasis in original). CEA concluded that the UCC Settlement meets the legislative intent of HB 1116 because it “acknowledges the value of DG and allows it to grow while ensuring that utilities are able to recover their costs of service and that no unjust or unreasonable cost-shift is occurring.” *Id.*

The OCA filed a post-hearing brief noting the movement by both settling groups from their original positions and characterizing the “two rival proposals [as] more alike than they are different.” OCA Post-Hearing Brief at 3-7. With respect to the significant differences between

the two settlement filings, the OCA asserted that the UCC's proposal to discontinue the distribution credit for exported energy would represent only a 14 percent decrease in the net revenue produced by a DG solar system and that is the type of modest "haircut" the Legislature is expecting to see." *Id.* at 9. The OCA also emphasized that elimination of the distribution credit "is in the nature of a compromise, to be considered alongside the retention of full credit for energy service and transmission service." *Id.* at 10. According to the OCA, both settling coalitions essentially base their distribution credit positions on the results of a negotiating process "rather than through an empirical exercise" evaluating record evidence. *Id.* at 10-11.

The OCA further argued there is evidence in the record that cost-shifting from DG customers to non-DG customers is a legitimate concern that should be addressed. *Id.* at 11-14. According to the OCA, the Commission "should not wait for the widespread deployment of [DERs] and advanced metering to confront the question of cost shifting, at which point there would be ample data to support the proposition that customer-generators are being overcompensated at the expense of their neighbors." *Id.* at 13. The OCA maintained that the legislative intent behind HB 1116 required such proactive mitigation, asserting that "the Legislature told the Commission to take steps *now* to avoid such a problem *in the future*." *Id.* at 13 (emphasis in original).

With respect to the differences between "instantaneous netting" and "monthly netting," the OCA challenged a number of the objections raised by EFC witnesses. *Id.* at 14-21. According to the OCA, sophisticated solar installers and developers should be able to provide their prospective customers with projections of at least the "best-case and worst-case scenarios based on their historical monthly usage data and/or data from typical residential customers." *Id.* at 15. The OCA further maintained that reliable predictions of future supply rates and

customer usage are limited regardless of the netting approach employed, and customers will have the ability to control their loads to respond to electricity market conditions. *Id.* The OCA also suggested that the potential financial impacts of the netting method change would be minimal, in particular in view of the recent significant decreases in solar installation costs. *Id.* at 17-19. The OCA criticized the EFC witnesses' arguments regarding inappropriate price signals, and asserted there was no record evidence that instantaneous netting would expose customer-generators to potential adverse federal income tax consequences. *Id.* at 19-21. The OCA characterized the EFC concerns regarding instantaneous netting as "nothing more than solar industry discomfort with the potential demise of a metering paradigm it found advantageous - but one that was developed by accident rather than via thoughtful policy deliberation." *Id.* at 21.

With respect to studies, data collection, and pilot programs, the OCA noted the substantial commonality between the two settlement proposals. *Id.* at 21-22. The OCA suggested that any disagreements between the settlement proposals be resolved "by adopting 'both/and' approach," that working groups be created to "fashion guidelines" for both studies and pilot programs, and that the Commission should "take care to assure that the research and insight sought by both coalitions is fully developed." *Id.* at 23. According to the OCA, the Commission "can and should conclude that a well-facilitated task force process will yield the requisite degree of cooperation and collaboration." *Id.* at 25.

The OCA concluded that, unlike the EFC Settlement, the UCC Settlement represents a "true settlement" that is a genuine compromise among parties "that are often not like-minded, began the case with conflicting approaches to the issues, and abandoned some fervently held views based on an assessment of litigation risk and a desire to find common ground in service of the greater good." *Id.* at 26. According to the OCA, the UCC Settlement is just and reasonable

and its approval would serve the public interest and comport with the intent of the Legislature in HB 1116 “to move New Hampshire out of the jury-rigged public policy that old-fashioned net metering [represents] in favor of a new approach that promotes distributed generation and prevents unfairness.” *Id.* at 27.

3. City of Lebanon

At hearing, City of Lebanon witness Below advocated that the Commission “strike a new balance somewhere between the two [settlement] proposals to best achieve the legislative purposes stated in HB 1116 ..., and support the just and reasonable findings that need to be made.” Tr. 3/29/17 A.M. at 104. He criticized the UCC Settlement in particular based on its implications for the “complicated process” of “truing up retail loads to wholesale,” with respect to customer-generators obtaining electric supply from a competitive electric power supplier. *Id.* at 110-114. Mr. Below recommended that monthly netting be continued “for at least a year, probably more like two years, and make a commitment to collect the data so we can compare instantaneous, preferably also hourly, to monthly netting, and everybody can know the ramifications of that before we sort of take the leap.” *Id.* at 117-118. He also expressed two separate concerns regarding the proposed change from monthly netting to instantaneous netting, which more closely resembles a “buy/sell” transaction with the interconnected utility. *Id.* at 122. First, if instantaneous netting effectively represents a sale for resale to the utility, then it might be deemed to fall outside of the PURPA definition of net metering, which refers to offsetting of energy over the applicable billing period. *Id.* at 122-123. Second, instantaneous netting may result in unintended adverse tax consequences, in terms of both the taxability of energy export credits and the availability of the investment tax credit. *Id.* at 123-131. With respect to the distribution credit amount for exported energy, Mr. Below maintained that many DG systems

consume on-site most of their output over the course of a month, and he recommended that, with monthly netting continued, the new net metering tariff could reduce to zero the distribution credit for net energy exports. *Id.* at 136-137.

The City of Lebanon filed a post-hearing closing statement, in which Mr. Below restated his view that this proceeding represents “an effort to move net metering policy from a rough justice to a more granular and refined justice.” City of Lebanon Closing Statement at 1. Given the current lack of data and analysis, Mr. Below asserted it is necessary “to take intermediate steps coming out of this proceeding to move in the right direction.” *Id.* He further requested that the Commission support and approve in concept the proposed City of Lebanon RTP pilot program, “understanding that implementation details, particularly as to metering and a transmission credit pilot tariff for large [net-metered] projects, will need subsequent Commission review and approval.” *Id.* at 1-2. Mr. Below also maintained that the Grid Mod Docket is relevant “in how this case is decided and the next steps toward ... further refinement of net metering terms and rates,” citing the “metering challenges and possible options to enable interval data and opt-in real time pricing.” *Id.* at 2-3.

With respect to netting methodology, Mr. Below stated the City’s belief that the record in this proceeding does not support a change from monthly netting, for other than non by-passable charges and other specific time-based rates “such as the hourly RTP pilot that the City is proposing.” *Id.* at 4. According to Mr. Below, instantaneous netting “creates a number of unreasonable problems that can be avoided by maintaining billing period netting for most purposes,” including inappropriate price signals for residential customers, lack of customer understanding of potential effects, potential federal regulation under PURPA if export credits are

considered energy sales rather than offsets, and potential adverse federal income tax consequences for residential customer-generators. *Id.* at 4-6.

Mr. Below also criticized the UCC Settlement provisions for energy export credits for customer-generators taking competitive supply service, based on the crediting of respective suppliers with sales revenues for all instantaneous imports while benefitting all suppliers through the process of adjusting retail load obligations to wholesale obligations. *Id.* at 6-7. He argued that “this structure creates a non-transparent and unreasonable and unjustified shifting of costs and benefits between various suppliers and their customers.” *Id.* at 7. According to Mr. Below, the EFC proposal to continue monthly netting avoids that problem and is also more consistent with ISO-NE’s “approach to only account for net hourly loads at wholesale meter points and the load estimation and reporting process used by Liberty.” *Id.* at 7-8 (citing Exh. 82 at 2).

With respect to the value of the distribution credit for customer-generator energy exports, Mr. Below concurred with the argument that “the value of net metered exports to the distribution grid (in isolation) are probably less than 100 percent, but more than 0 percent of the retail rate.” *Id.* at 8. He maintained it is likely that most small customer-generators’ annual generation “will be offset by consumption within the month of generation, leaving only some minority portion of their annual production as net monthly exports,” meaning that, with monthly netting, “most of the annual [net-metered] production would get full distribution rate credit.” *Id.* According to Mr. Below, the City of Lebanon, after hearing all of the evidence and testimony, “does not disagree with Staff witness Faryniarz’s testimony that ‘something in the range of 50 percent might minimize the error or the regrets going forward’ in the next immediate phase of net metering.” *Id.*

4. Freedom Energy Logistics

Freedom Energy Logistics (FEL) filed a post-hearing closing statement, in which it noted that Eversource's affiliated distribution companies in Massachusetts and Connecticut utilize monthly netting and have not proposed that instantaneous netting be adopted in those states, and asserted there is no basis for New Hampshire to "get out in front" of those states prior to Phase 2, because such a change "could well create end-user confusion and complicate marketing efforts by the DER providers and marketers." FEL Closing Statement at 1-2. FEL argued there is no basis for the Commission to exclude all distribution costs from the energy export credit rate prior to completion of the value of DER study and Phase 2 implementation, as such an exclusion would be "tantamount to saying that no distribution investment can ever be avoided by the implementation of DER." *Id.* at 2. FEL affirmed the conclusion of Staff's witness that "there is currently a relatively low penetration of DG in New Hampshire, and consequently there is not yet an unreasonable cost shift or lost revenue problem," and suggested that the amount of any cost-shifting for Eversource customers was likely to "decline substantially" as a result of the auction of the its generation assets, following which the amount of the Eversource "default service rate contained in the export rate will [go] down while the non-bypassable stranded costs included in the import charge will increase." *Id.* at 2, 5. FEL also suggested that the Commission would have greater latitude to consider and resolve issues raised by the two different settlement proposals because it had previously found that this proceeding is a "legislative docket and not an adjudicative proceeding." *Id.* at 5 (citing Order No. 25,980 at 8 (January 24, 2017)).

5. Staff

At hearing, Staff witness Faryniarz emphasized the current low level of DG penetration in New Hampshire and the “ratemaking principle of gradualism, suggest[ing] incremental reforms.” Tr. 3/29/17 P.M. at 88. He noted that the two settlement proposals “overlap in more areas than not, and both are consistent on many points with Staff’s rebuttal [testimony] recommendations.” *Id.* at 89. In response to a question from the bench, Mr. Faryniarz opined that the EFC Settlement “has more in the way of merit” in terms of its gradualism. *Id.* at 107. He also maintained that the EFC Settlement would send clearer and more efficient price signals, because monthly netting is more consistent with the current flat rate and monthly billing structure. *Id.* at 108.

Based on the gradualism principle, Mr. Faryniarz testified that a reduction from 100 percent distribution credit to a zero distribution credit would not make as much sense as “a movement, say to 50 percent of the distribution credit.” *Id.* at 109. He also asserted that a distribution credit amount “in the range of 50 percent might minimize the error or the regrets going forward into ... Phase 1, and then let’s get it right in Phase 2.” *Id.* at 114. He maintained that the record in this proceeding is insufficient to determine whether the “proper distribution credit is zero percent or 100 percent,” but expressed the view that over a longer time horizon the potential benefits of DG to the utility distribution system are likely to increase. *Id.* at 114-115.

With respect to the value of DER study period, Mr. Faryniarz testified that the period should focus on “system planning as opposed to the needs of either customer-generators or solar developers” and he referenced a ten-year period for utility least-cost planning. *Id.* at 110. According to Mr. Faryniarz, a study period in that range would allow for “the potential to recognize or view avoided distribution or transmission investments beyond a shorter-term

horizon,” but would not be so long that other significant influences such as technological or market changes might render the study conclusions unreliable or overly speculative.

Id. at 110-111. He further supported the view that the study should be updated periodically.

Id. at 112.

Mr. Faryniarz also addressed the level of detail and specificity regarding study design and parameters that should be prescribed, suggesting that the Commission might consider including “rails or guideposts” and specific deadlines in its order regarding studies, as well as reserving the right to direct the studies to be performed. *Id.* at 117.

6. Other Parties

Several parties offered oral closing statements on the final day of hearing. Kimberly Quirk spoke on behalf of Energy Emporium, citing the opportunity in this proceeding to support and encourage the clean energy industry in New Hampshire and realize the employment and economic benefits associated with its continued success. Tr. 3/30/17 at 33-38. According to Ms. Quirk, if a change from monthly netting were implemented, a DG customer’s economic payback would “go out by years, but it also becomes really difficult, nearly impossible, to forecast the savings for any homeowner.” *Id.* at 35. She asserted that such changes might make more sense once batteries or other energy storage technology are more generally available and affordable. *Id.* at 36-37.

On behalf of Norwich Technologies, Terry Donoghue expressed support for the EFC Settlement because it offers “a thoughtful, current compromise and pathway forward in determining future net metering rates in New Hampshire” and it “represents an incremental adjustment or that stability to those policies while a prescribed and objective valuation study can be performed.” *Id.* at 40-41. According to Mr. Donoghue, the current net metering policy

“results in both fairness to all parties and enables ... the deployment of local New Hampshire renewable energy generation facilities, with all their attendant economic, consumer, and environmental benefits.” *Id.* at 41.

Pentti Aalto described the benefits of market-based approaches and time-varying prices, but acknowledged that these may be future alternatives rather than current options. *Id.* at 42-55. In the nearer term, he asserted that, for smaller customers, “something like the full avoided cost that we’ve had in the past” could be maintained and this approach could be implemented with traditional analog metering. *Id.* at 51. According to Mr. Aalto, different structures should be explored for the larger customer-generators. *Id.* at 54-55.

Lee Oxenham noted the lack of data and studies available to support changes in the net metering program, and proposed that no changes be made to the current program for DG systems under 100 kilowatts during Phase 1, except for elimination of “the arbitrarily imposed cap on the total number of those systems.” *Id.* at 58-59. She suggested that, during Phase 1, efforts should be focused on the pilots and the value of DER study, perhaps by “leverag[ing] the millions of dollars already spent and being spent on related DER studies that are going on in adjacent jurisdictions.” *Id.* at 59. Ms. Oxenham also proposed that energy storage technologies be included in “the parameters of at least one of the pilots, and within the purview of the Value of DER study.” *Id.* at 61.

III. COMMISSION ANALYSIS

Pursuant to RSA 541-A:31, V(a), informal disposition may be made of any contested case at any time prior to the entry of a final decision or order, by stipulation, agreed settlement, consent order, or default. N.H. Code Admin. Rules Puc 203.20(b) requires the Commission to approve the disposition of a “contested case” by settlement if it determines that the settlement

results are just and reasonable and serve the public interest. We have previously determined that this proceeding is not a “contested case” subject to an “adjudicative proceeding,” but instead is “a legislative function [to be completed] at the direction of, and with guidance from, the legislature.” *See* Order No. 25,980 (January 24, 2017) at 8-11. In this proceeding, however, we have effectively elected to conduct a legislative rate-setting function through an adversary process using the Commission’s adjudicative procedures, including notice, hearing, and witness testimony under oath and subject to cross examination. *Id.* at 10-11. We therefore will apply Puc 203.20(b) in our consideration of the two settlements.

In general, the Commission encourages parties to attempt to reach a settlement of issues through negotiation and compromise, as it is an opportunity for creative problem solving, allows the parties to reach a result more in line with their expectations, and is often a more expedient alternative to litigation. *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH*, Order No. 25,202 at 17 (March 10, 2011). Even where all parties join a settlement agreement, however, the Commission cannot approve it without independently determining that the result comports with applicable standards. *Id.* at 18.

As stated above, the underlying standards to be applied in this proceeding are those specified in HB 1116. Under HB 1116, in developing new alternative net metering tariffs, we are required to consider the following factors:

- (1) the costs and benefits of customer-generator facilities;
- (2) an avoidance of unjust and unreasonable cost shifting;
- (3) rate effects on all customers;
- (4) alternative rate structures, including time based tariffs;
- (5) whether there should be a limitation on the amount of generating capacity eligible for such alternative net metering tariffs;

- (6) the size of facilities eligible to receive net metering tariffs;
- (7) timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; and
- (8) the electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms.

See RSA 362-A:9, XVI. As stated in the Order of Notice that initiated this proceeding, we will also be guided by the legislative purposes stated in HB 1116, including, among other things,

the continuance of reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair compensation for such locally produced power while ensuring costs and benefits are fairly and transparently allocated among all customers, and the promotion of a balanced energy policy that supports economic growth and energy diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits, a fair allocation of costs and benefits, and a modern and flexible electric grid that provides benefits for all ratepayers.

See Order of Notice at 2 (May 19, 2016).

We have considered the factors and purposes described above in reviewing and evaluating the two settlements. We note that, although the two settlements have some material differences, they are based on a set of shared premises and have many common elements. First, both settling coalitions agree that there is currently insufficient data to support final and definitive conclusions regarding the relative costs and benefits of DG and how those costs and benefits should inform the development of a new net metering tariff. Second, both settling coalitions agree that more data and other relevant information should be collected and disseminated, through pilot programs and utility processes, to inform a comprehensive value of DER study that will evaluate DG costs and benefits. Third, both settling coalitions agree that a new net metering tariff should be adopted and implemented during an interim period of several years while data is collected, pilot programs are conducted, and the value of DER study is

performed. Fourth, both settling coalitions agree that the new tariff should largely preserve the existing net metering structure, to permit a gradual and incremental transition, with certain significant modifications intended to mitigate potential adverse impacts on other electric distribution utility ratepayers.

We find that the record supports those shared premises and the common elements of the two settlements that are based thereon. Based on that finding, and the more specific findings regarding the relevant statutory factors described below, we approve the common elements of the two settlements, including the following specific provisions:

- (a) Installation of bi-directional meters to record in separate channels the quantities of electric imports from the grid and electric exports to the grid on a monthly basis;
- (b) Monetary crediting for electricity export compensation to replace kWh banking, with the opportunity to receive a cash payment for any accumulated excess monetary credits when customers move or discontinue service or on an annual basis if their credit balance exceeds \$100;
- (c) Net-metered customer-generators to pay certain non-bypassable charges, such as the system benefits charge, stranded cost recovery charge, storm recovery surcharges, and the state electricity consumption tax based on the full amount of their electricity imports without any netting of exports;⁵
- (d) Net-metered small customer-generators to be credited for their electricity exports at the utility's default service energy charge and for 100 percent of transmission charges assessed on a kWh basis, but with monetary crediting rather than kWh banking;
- (e) No current change in customer charges or application fees to apply, unless and until a utility makes a future filing for such a change based on demonstrated incremental costs;
- (f) Large customer-generators to receive export credits based only on the utility default service energy charge, but with monetary crediting rather than kWh banking;
- (g) Large customer-generators eligible for the new alternative net metering tariff only if they consume at least 20 percent of their actual or estimated annual DG system electric production behind-the-meter; otherwise, they must be registered as a group host under

⁵ We clarify that these charges will be the same as are assessed to all other customers, and as the charges may be increased or otherwise adjusted from time-to-time.

RSA 362-A:9, XIV; large DG system owners that meet the on-site consumption threshold would have the opportunity to switch to the new alternative net metering tariff;

- (h) Customer-generators that receive a net metering capacity allocation while the new alternative net metering tariff is in effect to be “grandfathered” at the applicable net metering design and structure then in effect through December 31, 2040;⁶
- (i) Utilities to have the opportunity to recover lost revenues attributable to customer net metering, pursuant to the mechanism and process approved for Unitil by Order No. 25,991 (February 21, 2017) in Docket DE 15-147; and
- (j) Utilities to be permitted to recover prudently-incurred costs of required metering upgrades, study expenses, and pilot program implementation.

With respect to the grandfathering provisions described in subparagraph (h) above, we have identified two issues regarding their implementation that were not addressed by any of the parties in this proceeding: (1) whether a subsequent sale or other ownership transfer of the house, building, or property upon which the DG system is installed, or a subsequent sale or other ownership transfer of the DG system itself, would entitle the new owner to continue to be net-metered under the grandfathered tariff provisions, and (2) whether subsequent expansions of or modifications to DG systems would be entitled to net metering under the grandfathered tariff provisions. We will provide an opportunity for the parties to address those two grandfathering implementation issues through written briefs or comments submitted within 30 days of the date of this Order, and then address those issues in a supplemental order to be issued in this docket.

Having approved the net metering tariff provisions that represent common elements of the two settlements, we now address those provisions that differ between the two settlements.

A. Netting Methodology

Small customer-generators with DG systems of 100 kW or less currently are net-metered using monthly netting. Those customers are billed by the utility for all kWh-based charges for

⁶ We clarify that any changes in underlying rates and rate designs would continue to apply to DG customers in the same manner as to all other customers in the same rate class, notwithstanding a customer-generator’s grandfathered status.

their net energy usage, which is the quantity of kWh “supplied to the customer over the electric distribution system minus the [kWh] generated by the customer-generator and fed into the electric distribution system *over a billing period.*” RSA 362-A:9, IV(a) (emphasis added). Large customer-generators are billed pursuant to the separate provisions of RSA 362-A:9, III and IV(b).

The UCC Settlement proposes to change the applicable netting methodology so that all kWh imported by a small customer-generator from the utility distribution system are charged the full amount of all kWh-based charges, while all kWh exported by the customer-generator to the utility distribution system are credited at the applicable export credit rate. The monetary credits are netted against the monthly charges. That netting methodology is enabled by the installation of a bi-directional meter which separately measures the total imports from the grid and the total exports to the grid in separate metering channels. The proposed transition to so-called “instantaneous netting” would represent a significant change for small customer-generators. The EFC Settlement, by contrast, would continue monthly netting, where imported kWh are netted against exported kWh once a month, and the appropriate rate is applied to the result, for most kWh-based charges. Under the EFC proposal, instantaneous netting would be implemented only for non-bypassable charges such as the system benefits charge, stranded cost recovery charges, storm surcharges, and the state electricity consumption tax.

We are persuaded by the record evidence that a near-term transition from monthly netting to instantaneous netting is likely to result in significant customer confusion, project marketing and development complications, and potentially inefficient customer price signals. For example, instantaneous netting may be confusing to customers who lack real-time data about their electricity usage. It may also provide financial incentives for maximum on-site electric

consumption during periods when the benefits of DG exports to the system may be greatest, such as at the time of late afternoon system peaks, thereby decreasing the potential system-wide benefits of those energy exports. We agree with Staff witness Faryniarz that “gradualism” is an important principle in sound ratemaking. *See, e.g.,* Exh. 65 at Bates 86, 159-160 (citing Bonbright, James C., *Principles of Public Utility Rates*, pp. 383-384 (1988)); Tr. 3/29/17 P.M. at 88, 107-109. An abrupt change from monthly to instantaneous netting would represent a significant discontinuity with the current net metering structure that may result in customer rate shock and confusion for residential DG system owners and other small customer-generators. We find that those would be adverse consequences that should be avoided in order to continue “reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair compensation for such locally produced power.” HB 1116 Sec. 31:1.

For non-bypassable charges, however, we will approve the transition from monthly netting to instantaneous netting, for small customer-generators, as agreed by both settling coalitions. All other kWh-based rate components shall be charged or credited based on monthly netting, as provided in RSA 362-A:9, IV(a), under which customers are billed for all kWh-based charges for their net energy usage, which is the quantity of kWh “supplied to the customer over the electric distribution system minus the [kWh] generated by the customer-generator and fed into the electric distribution system over a billing period.”

Having determined that monthly netting should continue for small customer-generators for most rate components, we find it unnecessary to address the UCC proposal to adopt special net metering credit provisions for customer-generators taking electricity supply service from competitive electric power suppliers, as those proposed provisions are associated with the

instantaneous netting alternative.⁷ Under RSA 362-A:9, II, registered competitive electricity power suppliers may continue to determine the terms, conditions, and prices under which they would agree to provide generation supply to and purchase net generation output from eligible customer-generators.

B. Distribution Credit Amount and Large Customer Transmission Credit

Both of the settling coalitions have proposed a reduction in the amount of the distribution credit for electricity exported by net-metered small customer-generators. The UCC proposes to reduce the distribution credit amount to zero, while retaining the default energy service and transmission rate credits at 100 percent. The EFC proposes to initially reduce the distribution credit to 75 percent and then ultimately to 50 percent during what they have termed “Phase 1.”

In neither case is there significant record evidence supporting the amount of the reduction proposed or the actual net benefits of DG energy exports to the utility distribution system, primarily due to a lack of relevant data and the current low level of DG penetration in New Hampshire. On the other hand, there is record evidence that the potential adverse effects of a distribution credit reduction are significantly diminished if monthly netting of energy produced by net-metered customer-generators is continued, because, as one witness put it, “a 50 percent cut in distribution applied with monthly netting is a small amount whereas a 50 percent cut in the distribution part of the export credit applied instantaneously is a much larger amount.”

Tr. 3/29/17 A.M. at 95 (EFC witness Hawes of Acadia Center).

Based on the limited evidence in the record, it appears that the actual net benefits of DG to the utility distribution system may be less than 100 percent of the utility distribution rate component, but greater than zero. We expect that the value of DER study will provide more

⁷ The potential PURPA sales and federal income tax issues raised by City of Lebanon witness Below are also related to the instantaneous netting proposal, and we therefore find it unnecessary to address those issues.

definitive information regarding the actual net costs and benefits of DG system deployments. In view of the current lack of evidentiary support for calculating the net export credit amount based on actual net benefits, we rely on general ratemaking principles, including the consideration of “gradualism” described above, and the goal of mitigating potential cost shifts, in determining the applicable credit for the distribution rate component. We note that the UCC proposal reached agreement on a 100 percent transmission credit and a zero percent distribution credit, intended to serve effectively as “rough justice” until actual costs are determined.⁸ We believe the balance tips in favor of the UCC proposal on this point, supported by the diverse interests of the OCA, other consumer advocacy groups, and the utilities, but we are not convinced that zero is the appropriate result.

Based on those considerations, we find that a reduction in the distribution credit amount for net-metered small customer-generators from 100 percent to 25 percent is warranted as a near-term, transitional measure. In the interests of simplicity and greater administrative efficiency, we find it unnecessary for any other interim reductions, such as a short-term reduction from 100 percent to 75 or 50 percent, to be implemented in the new net metering tariff.

We also decline to approve the EFC proposal that large customer-generators have the option to receive a transmission rate credit based on their actual avoidance through load reduction of marginal RNS and LNS transmission charges assessed by ISO-NE. Instead, we direct the utilities to collect and analyze relevant data to determine the potential effects of such marginal transmission charge avoidance through DG system operation.

C. New Tariff Effective Date

The UCC Settlement proposes that the new net metering tariff become effective on July 1, 2017, while the EFC Settlement proposes that the new tariff become effective on

⁸ See, e.g., Tr. 3/28/17 A.M. at 38-40 (testimony of NERA witness Harrington).

September 1, 2017. Neither of the settling coalitions expects that the utilities will actually be capable of implementing the new tariff provisions as of its proposed start date, so the tariff commencement date effectively serves as a cut-off date for grandfathering of projects under the current standard tariffs that provide for full retail rate net metering for small customer-generators and serves to provide certainty to large customer-generators in utility service territories where the statutory capacity cap has already been exceeded.

We are persuaded that potential DG customers, project developers, and system installers would benefit from additional time to prepare for and become educated about the transition from the current net metering program to the new net metering tariff provisions. We therefore approve a September 1, 2017, effective date for the new net metering tariff, such that any customers with DG projects receiving a utility net metering capacity allocation on or after that date (and any DG projects queued prior to that date in excess of the applicable statutory cap set forth in RSA 362-A:9, I) will be subject to the new net metering tariff provisions once the utility is capable of implementing those new provisions. If a utility is not capable of billing or crediting under the new net metering tariff as of the approved effective date, then DG projects will be billed and credited under the current standard net metering tariff rates until such time as the utility is capable of implementing the new net metering tariff provisions. Each utility should provide at least 30 days advance notice to its customers of the implementation date upon which billing and crediting under the new net metering tariff will commence.

D. REC Market Facilitation

The two settling coalitions both propose that the utilities would provide services intended to facilitate participation in the REC markets by small DG system owners, including the utilities' agreement to work with parties on the solicitation of a third party REC administrator and/or

aggregator and the utilities' facilitation of REC program promotion and customer education. They also agree that customer-generators will continue to own the RECs they produce with no obligation for the utilities to purchase those RECs. Other provisions regarding REC market facilitation differ between the two settlements.

The UCC Settlement proposes that the utilities would serve as independent monitors for customer-generators who want the utilities to monitor their electricity output and report that output to NEPOOL-GIS. In addition, the UCC proposes that customer-generators would have the option to request installation of a revenue grade production meter, at no cost to the customer, which would be owned by the utility and would provide customers with the data necessary to participate in the REC market. If a DG customer installs its own production meter, then the customer would be responsible for its own RECs, and the utility would estimate production from the system for lost revenue recovery purposes. The UCC proposes that the utilities would have the opportunity to file on an annual basis for recovery of costs associated with meters installed and related data management. The EFC Settlement would not require DG system customer-generators to have revenue-grade production meters, whether owned by the utility or otherwise. The EFC proposes that the utilities would work with customers, aggregators, and other relevant third parties to better facilitate the reporting and creation of RECs by customer-generators, and that the utilities would have the option to purchase RECs directly from a customer for a fixed fee.

We have reviewed the REC market facilitation proposals contained in the two settlements and find that a number of those proposals have merit while others are unnecessary. We approve the proposal for the utilities to serve as independent monitors for DG system owners, at the option of the customers, and certify their systems with the Commission and report their

electricity production at least quarterly to NEPOOL-GIS, as well as the proposal for the utilities to install production meters at the option of the DG system owners, all at no cost to those customers. We also approve the proposal for the utilities to facilitate REC program promotion and customer education, and direct the utilities to coordinate with Staff in connection with those efforts. DG system owners should continue to own the RECs they produce and the utilities should not be obligated to purchase those RECs, but may buy the RECs at reasonable market prices. We further conclude that the utilities should have the opportunity, during the period the new net metering tariff is in effect, to file for recovery of their prudently-incurred costs associated with independent monitoring services, bi-directional and production meters installed, and related data management systems and processes.

We find it is neither necessary nor appropriate for the utilities to solicit a third party REC administrator and/or aggregator to facilitate REC certification and sales for DG customers, and therefore we decline to approve that proposal by the settling coalitions.

E. Phase 2 Transition and Rate Design

The EFC proposes that new net metering tariffs be implemented in two sequential phases, with Phase 1 in effect through 2020, to be followed by development and implementation of the Phase 2 tariff by January 1, 2021. The Phase 2 tariff design as conceived by the EFC would be similar to the Phase 1 design, except that the amount of the distribution credit for exported electricity would be based on the results of the value of DER study. The UCC, by contrast, does not propose any particular timeline or design for any future iteration of a new net metering tariff, but commits to initiate a new proceeding before the Commission once more data has been developed, pilot programs have been conducted, and studies have been completed.

We do not believe it is necessary or appropriate to pre-determine when the next version of a new net metering tariff or other alternative mechanism will be developed or what that new tariff or alternative mechanism will contain and how it will operate. We expect that the next several years of pilots and studies will produce additional data and information regarding the respective costs, benefits, impacts, and effects of DG systems and their electricity exports, and that additional data and information will inform the Commission's review and evaluation of future net metering tariff modifications or alternative approaches. Those additional years are also likely to encompass technological and financial developments affecting both the DG industry and the electric utility industry, including those that may result from the Grid Mod Docket.

We anticipate that a new proceeding will be commenced to consider future net metering tariff modifications or alternative mechanisms once more data has been collected, including from the pilot programs to be conducted, and relevant studies have been performed. We are reluctant, however, to determine the timing and scope of that future proceeding at this juncture. We therefore decline to approve the EFC proposal regarding the timeline for and purpose of Phase 2.

F. Value of DER Study Scope

Both settling coalitions agree that a value of DER study should be performed under the supervision of the Commission, but they disagree in significant respects regarding the purpose and scope of the study. The UCC proposes that the value of DER study focus primarily on real-time prices and near-term marginal costs, with no long-term projections or forecasts to be considered, while taking into account actual costs to installers and customers related to the implementation of DER resources in New Hampshire. The EFC, by contrast, proposes that a long-term lifecycle value of DER study should serve as the basis for future valuation of DER

energy export credits, specifically focused on DG benefits to the utility distribution system and the appropriate value of the distribution charge export credit. The EFC proposes that the value of DER study be updated every three years and utilize the best available data and methodologies at the time of the study update. The EFC Settlement also would require Eversource to conduct a marginal cost-of-service study prior to the performance of the value of DER study.

We find that both settling coalitions have proposed value of DER study design parameters that are overly limited in scope. We believe Staff witness Faryniarz outlined in his rebuttal testimony an appropriate high-level scope for a useful value of DER study: it should be a long-term avoided cost study using marginal concepts and incorporating both TRC and RIM test criteria, and it may also include consideration of demonstrable and quantifiable net benefits associated with relevant externalities (such as environmental or public health benefits), provided that the potential for double-counting of such externalities is adequately mitigated. With respect to double-counting of externality benefits, if a potential DG benefit is included in wholesale electricity market price formation, either directly or indirectly, then it should not be included in the study scope. For example, all or part of the societal benefits of carbon reduction may be covered by the Regional Greenhouse Gas Initiative (RGGI) program, and RGGI costs incurred by fossil-fueled generators may effectively be included in the wholesale energy market bids of those generators. Under those circumstances, the resulting wholesale energy market prices would already incorporate those carbon reduction benefits and they would be taken into account through the energy component of the net metering credit and should not be counted as an additional benefit to be separately valued.

The study should focus primarily on solar photovoltaic systems and hydroelectric facilities, as those are the two generation technologies that most actively participate in net

metering. The methodology for conducting the value of DER study should be generally consistent with that used to evaluate energy efficiency resource standard program investments. We do not believe that specific developer or customer cost or financial information is needed for the study, but New Hampshire-specific or industry estimates of customer installed system costs are appropriate and should be included in the study. The study period should be longer than the 3-5 years proposed by the UCC, but shorter than the 25-year full DG lifecycle analysis advocated by the EFC. Consistent with typical system planning horizons, the study period should be 10-15 years, and should include present value analysis using appropriate discount rates. Because Eversource is in the process of divesting its generation assets and we anticipate it will be filing a general rate case within the next few years, we direct that Eversource perform a full marginal cost-of-service study within 12 months of the date of this Order, and make available to stakeholders in this proceeding the results of, and inputs to, that study as well as the methodology used in completing the study.

We believe that the determinations described above should provide guidance in the development of a more definitive value of DER study scope, which would then be used as the basis for the Commission to engage a qualified consultant to perform the study once sufficient data and other inputs are available. We also believe that development of the more definitive study scope would benefit from the involvement of stakeholders who are active in this proceeding. We therefore direct Staff to convene a working group of stakeholders to assist in the further development of the value of DER study scope and timing. The first meeting of the stakeholder working group should occur within 60 days following the date of this Order, and a final report containing the proposed value of DER study scope and timeline should be filed by

Staff within eight months from the date of this Order for review and approval by the Commission prior to engaging the study consultant.

G. Pilot Program Development and Implementation

The settling coalitions have both proposed that a TOU pilot program and a low and moderate income pilot program be approved by the Commission and initially implemented by the utilities during the period that the new net metering tariff will be in effect. Their proposals do not include many details as to how those pilot programs would be designed or implemented. Other pilot programs were also proposed by the UCC, the EFC, and the City of Lebanon. Under HB 1116, the Commission is authorized to “approve time and/or size limited pilots of alternative tariffs.” RSA 362-A:9, XVI. We have reviewed the proposed pilot programs and have determined that four pilots should be further developed for potential implementation in the near-term period.

First, we find that a well-designed TOU pilot program should generate detailed data regarding customer behavior and utility cost and rate impacts related to time-varying rates, and that data can inform future net metering and general rate designs, including a potential transition to TOU rate alternatives for all customer rate classes. Eversource and Unitil⁹ should each develop and propose a TOU pilot program, open to both residential and small commercial customers and to both DG and non-DG customers, with a statistically significant number of participants in each category to ensure the data and results generated by the program are statistically valid. It is not necessary that the TOU pilot program designs all be identical, nor that they cover only a single on-peak and off-peak differential. It is necessary, however, that the program designs reflect appropriate customer class load profiles and actual system conditions.

⁹ Because Liberty will develop an RTP pilot program with the City of Lebanon, as discussed below, we will not require Liberty to also develop a separate TOU pilot program.

Second, we approve the proposal to develop a pilot program that would use monetary bill credits to make the benefits of solar DG system ownership available to low and moderate income customers whose circumstances would otherwise not allow them to participate in a net-metered renewable energy project. Each utility should develop for our consideration such a pilot program, to include a statistically significant number of program participants, if possible, in order to ensure data validity. We note that Senate Bill 129, if enacted, would require the funding and implementation of certain programs and projects intended to benefit low and moderate income residential electric customers. We direct the utilities and Staff to develop pilot programs that are consistent with, and not duplicative of, any such other programs and projects required under enacted legislation.

Third, we find that the RTP pilot program proposed to be implemented by the City of Lebanon with Liberty, through a municipal aggregation and using a competitive electric power supplier, represents an innovative and forward-looking project that may generate useful data regarding customer behavior and utility rate impacts. We direct Liberty to work with the City to develop the proposed RTP pilot program for filing with the Commission. We will not require that the City of Lebanon RTP pilot program be developed through the stakeholder working group process described below, but we will require that the data resulting from the pilot program be made available to stakeholders in this proceeding, provided that the privacy of any customer-specific information is adequately protected.

Finally, we believe that well-designed non-wires alternative pilot programs may provide valuable experience and data demonstrating the effects of DG on potentially-stressed components of the utility distribution system at specific locations. Such pilots should also provide insight into the incentive levels needed by DG developers to site their projects where

they would have the greatest potentially positive impacts. We therefore approve the EFC proposal that the utilities develop non-wires alternative pilot programs focused on the installation of DG in lieu of potential utility distribution system upgrades. There should be at least one such pilot program location in each utility service territory, assuming appropriate locations can be identified, and Eversource should have at least three such locations. The utilities should identify all distribution circuits or substations that are planned for upgrades within the next 5 years, the reason for the planned upgrades, the reliability criteria and benefits of the planned upgrades, and the estimated costs of the planned upgrades. The utilities should also propose for Commission review and approval the specific locations on such circuits or affecting such substations where they believe pilot programs should be implemented. If the identification of those specific locations requires a study, then the necessary study should be performed. We will not, however, require the utilities to conduct a locational value study similar to the Nexant Study. DG projects should be selected to participate in the pilot program through a competitive solicitation process overseen by a neutral third party consultant engaged by the Commission. The projects selected should be those that meet the relevant reliability criteria and result in the greatest utility cost avoidance or deferral, net of the incentives required to be paid pursuant to the project developer's bid proposal, determined on a present value basis using the utility's weighted average cost of capital as the applicable discount rate.

The data resulting from any approved and implemented pilot programs should be made available to a broad range of interested stakeholders, as well as Staff and Commission consultants, provided that the privacy of any customer-specific information is adequately protected. We expect that the resulting data may also be useful in other relevant contexts, such as the development of projects or initiatives in connection with the Grid Mod Docket. With

respect to the pilot program development process, we believe that the utilities should propose pilot program designs and related evaluation, measurement, and verification (EM&V) plans in the first instance, to be reviewed and discussed with interested stakeholders through a working group process similar to that contemplated for the value of DER study design, with the exception, as noted above, of the City of Lebanon RTP pilot program, which should be developed by the City and Liberty. The first meeting of the stakeholder working group should occur within 60 days following the date of this Order. We encourage the utilities to consider the use of qualified expert consultants in the pilot program development process, to the extent necessary or appropriate, and the sharing of expert consulting services among the utilities, to the extent feasible and cost-effective. Following the completion of the applicable working group process, detailed proposals for implementation of the four pilot programs and related EM&V plans, and detailed estimates of related implementation costs, should be filed by the respective utilities for review and approval, rejection, or modification by the Commission following notice and hearing. We will evaluate the potential benefits and costs of each pilot program proposal to determine whether it is cost-effective from the perspective of future net metering tariff development. The development process should be designed with the goal of having all four of the pilot programs approved and initially implemented within 18 months from the date of this Order, to the extent possible. The utilities should have the opportunity to recover their prudently-incurred costs of development and implementation of all approved pilot programs.

We decline to approve the “Smart Energy Home Rate” pilot program proposed in the EFC Settlement, which would be designed to test rate designs such as RTP, critical peak pricing, demand charges, or other structures that enable customers to adopt a variety of technologies and behaviors to manage their electricity consumption. Although it is an intriguing and progressive

proposal, we believe the four pilot programs we have approved for development represent the best near-term commitment of limited utility resources and potential customer engagement. We also believe the “Smart Energy Home Rate” pilot proposal may overlap significantly with similar programs that may be considered in the context of the Grid Mod Docket, and such a proposal may be best considered in that separate context.

H. Data Collection and Dissemination

The UCC proposes that the utilities provide data on annual loads for net-metered customer accounts for one or more years before the customers interconnect their net metered systems, where available, together with annual average loads for comparable time periods for customer accounts that did not adopt net metering, for purposes of comparison. The EFC generally maintains that additional data must be collected and disseminated for use in the value of DER study to determine the net benefits and costs of DG systems and in the evaluation of potentially beneficial locations for DG system installation.

We will provide some further guidance regarding the scope of the data to be collected and disseminated to interested stakeholders, while leaving the more detailed specification of data collection requirements to be developed through a stakeholder working group process. It is likely that the value of DER study design parameters will affect the type of data required to be collected during the next several years and the specific timeline for that collection. In addition, we believe the utilities should collect and make available load shape data for individual distribution circuits, or at least for a selected sample of distribution circuits, as well as customer load data on an hourly or shorter interval basis for at least a representative sample of customers, provided that the privacy of any customer-specific information is adequately protected. As with data resulting from any approved and implemented pilot programs, we expect that the utility data

to be collected and disseminated may also be useful in other relevant contexts, such as the development of projects or initiatives in connection with the Grid Mod Docket.

With respect to the process for development of definitive data collection specifications and timelines, we believe that the utilities should propose data collection plans in the first instance, including detailed current cost estimates. Those plans would then be reviewed and discussed with interested stakeholders through a working group process similar to that contemplated for the value of DER study design and for pilot program development. Following the completion of the working group process, final detailed plans for data collection and dissemination should be prepared and implemented. If necessary to resolve disputed issues that cannot be worked out by the stakeholders, the data collection and dissemination plans may be submitted to the Commission for review and determination. The utilities should have the opportunity to recover their prudently-incurred costs of the required data collection, maintenance, and dissemination, and should include detailed estimates of those costs in their proposed and final plans.

I. Statutory Standards and Legislative Guidance for Net Metering Tariff Approval

We find that the new net metering tariff provisions we have approved, including both those that were commonly agreed to and those with respect to which we have resolved differences, are just and reasonable and serve the public interest, consistent with the requirements of Puc 203.20(b). We have also concluded that the approved net metering tariff provisions comport with the applicable statutory standards and legislative guidance, which we will now address in more detail.

Under HB 1116, as codified in RSA 362-A:9, XVI, in developing a new alternative net metering tariff, the Commission is required to consider a list of eight separate factors, which are described below:

1. Costs and Benefits of Customer-Generator Facilities. The record in this proceeding evinces a lack of definitive evidence regarding the relative costs and benefits of DG systems from the perspectives of the utility distribution system and other electric customers. We are confident that this deficit will be addressed by the data collection, potential pilot programs, and value of DER study we have approved for development over the next few years. In the near term, we believe that, based upon the record before us, the net metering tariff export credit rates we have approved are reasonable.

2. Avoidance of Unjust and Unreasonable Cost-Shifting. With respect to the avoidance of unjust and unreasonable cost-shifting, based on the evidence presented in this proceeding and the current, relatively low DG penetration levels in the State, we find that there is little to no evidence of any significant cost-shifting. Nevertheless, we agree with the parties and believe it is prudent to adopt new net metering tariff provisions to mitigate the potential for future cost-shifting, and we believe the new net metering tariff provisions we have approved further that objective by requiring net-metered small customer-generators to pay non-bypassable charges based on all of their electric energy imports and by reducing by three-quarters the distribution charge credit for their electric energy exports. We will continue to monitor potential cost-shifting and other customer rate impacts of net metering over the next several years, and review the issue once again in conjunction with development of future net metering tariff and rate designs.

3. Rate Effects on All Customers. For the reasons described in paragraph 2 above, we believe that the potential for unjust and unreasonable cost-shifting from net-metered customers to non-DG customers is adequately addressed through the new net metering tariff provisions. The potential rate effects on net-metered customer-generators themselves are reasonable, and the grandfathering provisions serve to preserve the value of the investments they have made in DG systems. The new net metering tariff makes no changes to the rates charged to customers without DG systems.

4. Alternative Rate Structures, Including Time-Based Tariffs. We have considered the potential for alternative rate design structures, including the use of time-varying rates for net-metered customer-generators, and we believe those alternatives may have great potential for future implementation. We also anticipate that time-based rate designs for some or all customer classes may be considered as potential initiatives resulting from the Grid Mod Docket. In the near term, however, we believe that the approach of incremental changes to the current net metering rate structure, as advocated by both settling coalitions and Staff's expert, represents the best option for continuation of net metering. We anticipate that the TOU and RTP pilot programs we have approved for development would provide useful data and information regarding the potential for implementation of time-varying rate designs on a broader scale, and we look forward to reviewing that data and information in a future proceeding.

5. Limitations on Amount of Eligible Generating Capacity. Neither of the two settling coalitions, nor any other party in this proceeding, has proposed that a limitation on the amount of eligible generating capacity be adopted. In light of that consensus, and the current low levels of DG penetration in New Hampshire, we do not believe it is necessary to impose any limitation on

the amount of generating capacity eligible for the new net metering tariff provisions during the anticipated limited duration of the new tariff.

6. Size of Facilities Eligible for Net Metering. We agree with the two settling coalitions that the current 100 kW demarcation point between small and large customer-generators should be continued in the near term, in the interest of implementing only incremental changes while maintaining the current net metering tariff structure during that time period.

7. Timely Utility Recovery of Lost Revenue Using LRAM. Consistent with the concurrence of the two settlement proposals, we have adopted a reasonable and appropriate mechanism for determination and collection of utility lost revenues attributable to net metering, based on the process and methodology approved for Unitil by Order No. 25,991 (February 21, 2017) in Docket DE 15-147.

8. Utilities' Administrative Processes Required for New Tariff Implementation. Because the new net metering tariff provisions are generally based on the existing net metering tariff structure, consistent with the common elements of both settlement proposals, we do not anticipate that the administrative processes required for implementation of the new tariff will be unduly burdensome or expensive for the utilities. We also recognize that the utilities should have a reasonable opportunity to recover their prudently-incurred costs of billing, metering, and data processing changes needed to implement the new net metering tariff provisions, as well as those costs related to data collection and dissemination, value of DER study performance, and potential pilot programs we have approved for development.

In addition to our consideration of the eight statutory factors, we are guided in our decision by the stated legislative purpose of HB 1116 to continue “reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair

compensation for such locally produced power while ensuring costs and benefits are fairly and transparently allocated among all customers.” We believe we have struck an appropriate balance for now between the potentially competing objectives of continuing reasonable opportunities for DG system investment and deployment and allocating on a fair and reasonable basis the respective costs and benefits of those net-metered systems. We emphasize that this determination in no way prejudices any future modification of or alternative to net metering that the Commission may consider and approve in a subsequent proceeding, once more data and information is available and the value of DER study has been completed.

Finally, we recognize that a number of the provisions of the new net metering tariff we approve in this Order are not fully consistent with the current Puc 900 rules regarding net metering. Any such inconsistent rules provisions should be deemed to be superseded by the net metering tariff provisions we approve in this Order. We direct Staff to begin the process of reviewing the Puc 900 rules to determine the amendments necessary to achieve consistency with the new net metering tariff provisions, and we will then initiate a rulemaking docket to propose such rules amendments.

IV. CONCLUSION

In summary, we approve the common elements of the two settlement proposals filed in this proceeding and resolve the differences between those two settlements. Our approval and resolution provides for a near-term continuation of net metering in New Hampshire while a longer-term process of valuation and redevelopment is pursued.

Based on the record developed in this proceeding, we adopt an alternative net metering tariff to be in effect for a period of several years, under which small customer-generators with renewable energy systems of 100 kW or less will continue to net meter their DG resources with

monthly netting. Those customer-generators will receive monthly net export credits equal to the monetary value of kWh charges for energy service and transmission service at 100 percent and distribution service at 25 percent, while they pay the full amount of non-bypassable charges, such as the system benefits charge, stranded cost recovery charge, other similar surcharges, and the state electricity consumption tax, for all of their electricity imports from the utility grid.

Large customer-generators will continue to be net-metered as they are currently, except they will also receive monetary bill credits rather than kWh credits on a monthly basis. To provide certainty to DG customers and investors, we have determined that DG systems installed or queued during the period the new net metering tariff is in effect should have their net metering rate structure “grandfathered” until December 31, 2040.

As the penetration level of DG in the State is quite low in both absolute and relative terms, there is little evidence of significant cost-shifting from DG customers to customers without DG. Payment of non-bypassable charges by all net-metered customers and a reduction in the distribution credit for net exports should serve to mitigate the potential for such cost-shifting, even if DG penetration levels increase significantly above their low levels.

While the new net metering tariff is in effect, additional system and customer data will be collected, disseminated, and analyzed (subject to appropriate privacy protections); relevant pilot programs will be developed and proposed for implementation; and a value of DER study will be designed and completed. The data, information, and study conclusions resulting from those initiatives ultimately will inform the development of the next version of net metering or another alternative regulatory mechanism. Following completion of the value of DER study, and with the availability of the additional customer load and system planning and operations data, the

Commission will open a new proceeding to determine whether and when further changes should be made to the net metering tariff structure.

As this matter progressed, it became clear that certain assumptions about relevant issues required more in-depth evaluation. Those who assumed large cross-subsidies in favor of DG customers and those who assumed large quantifiable benefits of DG were challenged by each other and, in the end, almost all of the participants joined compromise settlement proposals that are more alike than they are different. They also agreed on the need to develop more extensive and detailed data, and to engage in a number of pilot or test programs.

The two-phase process of tariff implementation and development we adopt today meets the legislature's direction in HB 1116 and satisfies the statutory criteria for approval. Consistent with our legislative mandate, we believe the various compromises by the stakeholders and the decisions we make today strike an appropriate balance between the potentially competing objectives of continuing reasonable opportunities for DG system investment and deployment while mitigating potential cost-shifting and allocating on a fair and reasonable basis the respective costs and benefits of net-metered DG systems. The process also charts a course forward for development of a next-generation net metering or alternative DG tariff structure informed by actual real-world data and valid study results.

Based upon the foregoing, it is hereby

ORDERED, that the common elements of the two settlement proposals filed in this proceeding are accepted and approved and the differences between the two settlement proposals are resolved, as set forth in the body of this Order; and it is

FURTHER ORDERED, that each of Public Service Company of New Hampshire d/b/a Eversource Energy, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities, and

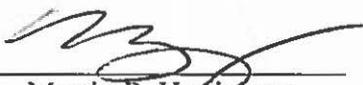
Unitil Energy Systems, Inc. shall file, pursuant to Part Puc 1603, revised tariff pages conforming to this Order within 30 days following the date of this Order; and it is

FURTHER ORDERED, that stakeholder working groups shall be convened within 60 days of the date of this Order to develop proposals for pilot program implementation, data collection and dissemination specifications and timing, and the scope and timeline for conducting the value of DER study, as described in the body of this Order; and it is

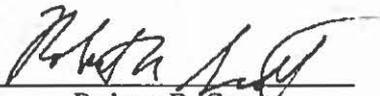
FURTHER ORDERED, that reports of the status and progress of the stakeholder working group process shall be filed on a quarterly basis by Commission Staff; and it is

FURTHER ORDERED, that parties shall have the opportunity to submit written briefs or comments within 30 days following the date of this Order addressing the two grandfathering implementation issues identified in the body of this Order.

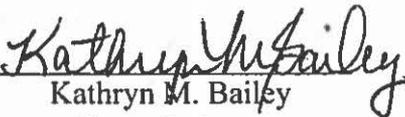
By order of the Public Utilities Commission of New Hampshire this twenty-third day of June, 2017.



Martin P. Horigberg
Chairman

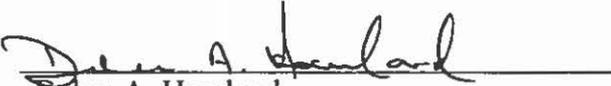


Robert R. Scott
Commissioner



Kathryn M. Bailey
Commissioner

Attested by:



Debra A. Howland
Executive Director