THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISISON

DE 22-060

ELECTRIC DISTRIBUTION UTILITIES

Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators

Community Power Coalition of New Hampshire

Direct Testimony of Clifton C. Below

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I. Introduction

Q. Please state your name, business address, and position with regard to the docket.

A. My name is Clifton C. Below and my office address is 1 Court Street, Suite 300, Lebanon, NH 03766. I am Chair of the Board of Directors of the Community Power Coalition of New Hampshire ("CPCNH" or the "Coalition''), which was granted intervenor status in this docket.

Q. Please describe your background and experience with regard electric utility regulation and energy policy.

A. I graduated from Dartmouth College in 1980 with distinction in my major of Geography and Environmental Studies. My course work included New England Energy Futures, Environmental Systems, Environmental Policy Formulation, and engineering courses in Community Systems (e.g. electric and water utilities) and Principles of Systems Design. In 1985, I earned an M.S. in Community Economic Development from Southern NH University, with course work in such areas as accounting, financial and organizational management, financing, and business development. During this time, I became a partner in the development of two commercial buildings on urban renewal parcels that helped to revitalize downtown Lebanon. I continue to operate and manage one of those two buildings that enabled me to begin serving in the New Hampshire legislature for 12 years starting in 1992 and do this volunteer work on behalf of CPCNH.

At the start of my first term in 1992, I was appointed to the House Science Technology and Energy (ST&E) Committee. The first study committee that I was appointed to was the "Small Power Producers and PSNH Renegotiations Legislative Oversight Committee" that gave me a crash course into LEEPA and PURPA issues, as well as the tension between competition and regulation, as over-market contracts with independent power producers (also known as qualifying facilities or QFs) were being renegotiated. Those contracts and the PUC rate order approving them were originally justified by the same load and rate projections that were used to justify continued investment in the Seabrook nuclear station.

In 1995, I Chaired the Policy Principles, Social and Environmental Issues Subcommittee of the Retail Wheeling and Restructuring Study Committee. In that role, I worked closely and collaboratively with then ST&E Chair Rep. Jeb Bradley and many other legislators and stakeholders to craft a consensus report and recommendations that became the foundation for NH's Electric Utility Restructuring statute, RSA 374-F, the enactment of which enjoyed broad bipartisan support and was the first such statute in the nation to call for customer choice in generation supply. In 1996, Rep. Bradley and I provided joint written and in-person testimony before the Energy & Power Subcommittee of the U.S. House Committee on Commerce on State and Federal issues related to electric utility restructuring on behalf of the NH House of Representatives. In 1997 I sponsored HB 485 with my co-sponsor Rep. Bradley that reformed the NH LEEPA statute, RSA 362-A, and first established net energy metering in New Hampshire in 1998.

After I was elected to the New Hampshire State Senate in 1998, I was approached by Attorney Tom Rath and the CEO of Northeast Utilities (NU, owner of PSNH, now Eversource) and was asked to be the prime sponsor of (then, controversial) securitization legislation that NU saw as critical to resolving PSNH's litigation against NH's electric utility restructuring. I did so, and in 2000, I was part of the team that negotiated a resolution of PSNH's litigation with the enactment of RSA 369-B with strong bipartisan support that enabled restructuring to proceed in New Hampshire. Throughout my 12-year tenure in the legislature, I always served on the policy committees that dealt with energy and electric utility issues and became active in regional and national forums. For example, from 1997-2004, I served on the Advisory Council on Energy of the National Conference of State Legislatures (NCSL), including 3 years as Chair and the Energy & Electric Utilities Committee, Assembly on Federal Issues, where, as Chair in 2000-2001, I facilitated a consensus based comprehensive update of NCSL's National Energy Policy (and other policies) used for lobbying the federal government on behalf of all state legislatures. I testified before the United States Senate Committee on Energy and Natural Resources on "Electric Industry Restructuring," with a particular focus on transmission issues, on behalf of NCSL. I also served as a member of the National Council on Electricity Policy, Steering Committee from 2001-2004.

After declining to seek reelection to the State Senate, Governor Lynch nominated me to the NHPUC, where from the end of 2005 into 2012 I served as a Commissioner. As Commissioner, I read reams of testimony, participated in examination of witnesses and the adjudication of some 360 cases with public hearings. I was active in ISO New England stakeholder processes and other regional and national forums on behalf of the NHPUC and the State. I served on the National Association of Regulatory Utility Commissioners (NARUC) Energy Resources & Environment Committee for 6 years including 3 as a Vice-Chair. I also served on the FERC-NARUC Smart Grid and Demand Response Collaborative, 2008-2011; and on the Electric Power Research Institute (EPRI) Advisory Council, 2009-2011; and its Energy Efficiency/Smart Grid Public Advisory Group, 2008-2010. I also served as President of the New England Conference of Public Utility Commissioners (NECPUC) from 9/2010 to 9/2011 during which time I was involved in early advocacy for "pay for performance" for winter capacity payments including the enablement of aggregated retail demand response programs participating in the ISO-NE markets as states had not yet enabled distributed energy resources to be able to respond to temporal price signals in the federal wholesale electricity market.

I provided direct, rebuttal, and live testimony in DE 16-576, the net metering docket that developed alternative net energy metering tariffs (which I refer to as NEM 2.0, with NH's original net metering referred to NEM 1.0, and any revised tariffs coming out of this docket referred to as NEM 3.0). The City of Lebanon had also proposed a time-based NEM compensation pilot in collaboration with Liberty Utilities in that docket, which the Commission conceptually approved, but in the end, it was not feasible due to metering constraints and requirements in RSA 53-E, through which we were planning to operate the pilot as an "opt-in" municipal aggregation. Subsequently, I turned my focus to updating RSA 53-E and establishing the Community Power Coalition of New Hampshire with other communities. I have added additional relevant background and experience as Attachment 1. For convenient reference, I have also attached an annotated version of NH's net metering statute and related definitions and statutory purpose statement, a version of which I shared with DE 22-060 stakeholders last winter as Attachment 2.

II. Overview of Issues

Q. What is the Community Power Coalition of New Hampshire's interest in future net metering tariffs?

A. The Coalition is a joint powers agency of 48 NH municipalities and one county, with membership growing every month.[1] Our current members comprise about 30% of the state's population. CPCNH currently serves ~80,000 electric customers in 14 community power aggregations (CPAs) with expectations to launch all current members by 2025. We are the 3rd largest supplier of electricity in NH by customer count and we will soon be the 2nd largest supplier after Eversource default service. As an alternative default service supplier to the distribution utilities (RSA 374-F:2, I-a), the members of CPCNH want CPCNH to offer net metering rates and programs, pursuant to our adopted community electric aggregation plans (EAPs). RSA 53-E:6, III(f) requires EAPs to detail "[h]ow net metered electricity exported to the distribution grid by program participants, including for group net metering, will be compensated and accounted for" and as we are entitled to do pursuant to RSA 362-A:9 II. RSA 362-A:9, II provides that "municipal or county aggregators under RSA 53-E may determine the terms, conditions, and prices under which they agree to provide generation supply to and credit, as an offset to supply, or purchase the generation output exported to the distribution grid from eligible customer-generators."

The Coalition was formed to support the creation of CPAs "as a competitive means for local governments to achieve their local policy goals and assume the responsibility of providing electricity service to their residents and businesses that do not choose an alternative supplier" and to "allow communities to promote renewable and distributed energy development, energy efficiency programs, price stability, access to innovative energy products, services, and rates, and local economic benefits through local control."[2] CPCNH wants to ensure equitable treatment of customers on competitive supply, CPA service, and utility default service, and help drive economic efficiency through open access to competitive markets and price signals that will help realize an affordable, equitable, and sustainable energy future.[3]

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[1] A complete list of our current members is attached as Attachment 3.

[2] Recitals, p.1 of the Joint Powers Agreement of the CPCNH, available under "Key Documents" at www.cpcnh.org.

[3] Paraphrased from "Regulatory and Policy Principles" p. 2 of the CPCNH Charter of the Regulatory & Legislative Affairs Committee.

Member municipalities "have substantial responsibilities and authority for land use planning, including adoption of master plans that may address transportation, utility and energy planning among other needs pursuant to NH RSA 674:2, zoning, development review, building and fire code administration, adoption of "stretch" codes pursuant to NH RSA 155-A:2, V, and creation of energy commissions pursuant to NH RSA 38-D for the study, planning, and utilization of energy resources and making recommendations on sustainable practices."

Many CPCNH member municipalities have net metered electric accounts with renewable generation and own additional buildings and sites suitable for additional distributed generation (DG) and distributed energy storage (DS) facilities. Municipalities also have the authority to plan, construct, finance, own, operate, and sell power from distributed electric generation facilities pursuant to RSA 374-D, RSA 33-B and 53-E. Additionally, municipalities have the authority to finance with tax-exempt revenue bonds investments in new NEM projects as part of Commercial Property Assessed Clean Energy (CPACE) as part of multi-family and commercial energy efficiency and renewable energy upgrades pursuant to RSA 53-F. Many members have energy and climate action plans with aggressive renewable and clean energy goals, including goals to meet municipality energy needs with 100% renewable energy, with a focus on using as much local renewable energy as possible. Other municipalities are focused on ratepayer affordability with a goal to consistently ensure that CPCNH delivers the most competitive energy rates available.

Municipalities and their municipal aggregations (CPAs) are also uniquely situated to be "municipal hosts" (and their group members) which, pursuant to RSA 362-A:1-a, II-b "means a customer generator with a total peak generating capacity of greater than one megawatt and less than 5 megawatts used to offset the electricity requirements of a group . . ." As presently only municipal hosts can develop or sponsor NEM projects greater than 1 MW up to under 5 MW, CPCNH is particularly interested in the NEM 3.0 tariffs for greater than 1 MW.

As we represent both the customers we serve and the voters to whom we are accountable, our interest is acute in transitioning to a more market-based, competitive, and beneficial NEM 3.0 paradigm that will allow NH communities to accelerate the transition to a clean and sustainable energy future. Getting the price signals right in NEM 3.0 will result in the most cost-effective investments in the development and integration of distributed energy resources.[4] Better price signals will result in better investments.

Q. Are the goals of RSA 374-F relevant to CPCNH's proposal?

A. Yes. I think it will be helpful to consider some of goals and principles expressed in RSA 374-F, enacted into law over 27 years ago, to help inform the weight to be given to various rate design principles in evaluating proposed tariffs in this case (with emphasis added):

> **374-F:1 Purpose. –**
>
> I. The most compelling reason to restructure the New Hampshire electric utility industry is to **reduce costs for all consumers of electricity by harnessing the power of competitive markets**. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment. **Increased customer choice and the <u>development of competitive markets for</u> wholesale and <u>retail electricity services</u> are key elements in a restructured industry** . . .
>
> II. A transition to competitive markets for electricity is consistent with the directives of part II, article 83 of the New Hampshire constitution which reads in part: "Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it." **Competitive markets should** provide electricity suppliers with incentives to operate efficiently and cleanly, **open markets for new and improved technologies**, **<u>provide electricity buyers and sellers with appropriate price signals</u>**, and improve public confidence in the electric utility industry."
>
> **374-F:3 Restructuring Policy Principles. – . . .**
>
> II. Customer Choice. . . . **Customers should be able to choose among options such as** . . . **real time pricing, and generation sources including interconnected self generation** . . . ."

While good rate and tariff design requires the balancing of a variety of principles and objectives, New Hampshire policy clearly gives considerable weight to customer choice, the development of competitive markets, including, of note, for **<u>retail</u>** electricity services, and the

[4] RSA 374-F:2, VII. "'Distributed energy resources' or "DER" means demand response, distributed generation, and distributed storage." "VI. "Demand response" means a reduction in the use of electricity by retail electricity energy customers in response to power grid needs, economic signals from their electricity supplier based on wholesale market prices, or time varying rates." VIII. "Distributed generation" or "DG" means a customer-generator as defined in RSA 362-A:1-a, II-b or a limited producer as defined in RSA 362-A:1-a, III, excluding qualifying storage systems and grid-interactive electric vehicles. IX. "Distributed storage" or "DS" means qualifying storage systems as defined in RSA 362-A:1-a, IX-a, grid-integrated electric vehicles when they are interconnected to a New Hampshire jurisdictional distribution grid behind a retail electric meter, or energy storage as defined in RSA 374-H:1, III, that are not participating in any wholesale energy markets administered by ISO New England as a registered asset or otherwise.

provision of "appropriate price signals." In this context, it seems apparent that "appropriate price signals" include those that achieve economic and operational efficiency and help achieve expressed public policy goals such as "maintaining safe and reliable electric service with minimum adverse impacts on the environment." New Hampshire statutory policy calls out specifically for customers to have the choice of real time pricing. Even as that concept and practice was still relatively new and limited to wholesale markets a quarter of a century ago, it was apparent to legislators that enabling retail load (customers) to respond to temporal price signals in supply markets is important to economic efficiency and productivity. While considerable effort has gone into developing wholesale supply markets in New England, we can do a better job connecting wholesale market price signals to retail consumption and supply markets and enabling small customers and customer-generators to have greater participation in retail electricity market choices.

Q. Are there other rate design principles that inform your testimony?

A. Yes, many of the principles first developed by James Bonbright and Alfred Kahn remain relevant today. Rates should yield the revenue required for regulated monopoly services in a stable and predictable manner. Rates should reflect cost causation, avoid undue discrimination, and fairly apportion costs among customer classes; and, I would argue increasingly, in this day and age, among individual customers. Furthermore, rates should promote economically efficient consumption and investment and promote innovation in supply and demand. Rates that are forward looking and reflect marginal costs, especially long-term marginal costs when long-term investments are involved, can efficiently harmonize utility and customer investments, choices, and benefits. Better translation of existing wholesale market prices signals for both generation services and transmission services to retail load and customer-generators are key in this regard.

Q. What statutory requirements need to be addressed in this proceeding?

A. The Commission summarized the issues presented in their 9/21/22 Order of Notice. They are based on the text in RSA 362-A:9, XVI(a) and XXIII. My testimony will address most, if not every issue referenced. Sandwiched in between those two paragraphs, giving a sense of when it was added to the statute, is RSA 362-A:9, XXI(a) which states:

> The commission shall consider the question of whether or not exports to the grid by customer-generators taking default service should be accounted for as reduction to what

> would otherwise be the wholesale load obligation of the load serving entity providing default service absent such exports to the grid. The commission shall use its best efforts to resolve such question through an order in an adjudicated proceeding, which may be DE 16-576, issued no later than *June 15, 2022* (*emphasis added).*

No such resolution has occurred. Although not explicitly referenced in the order of notice, this matter is broadly within the scope of considering new net metering tariffs and other regulatory mechanisms. I did note this issue at the pre-hearing conference (Tr. at 26-27) and argue here that its resolution is intrinsic to others issues to be addressed and the implementation of any new alternative net metering tariffs. Responses from rate (price) signals such as exports to the grid in a net metering example need to be accounted for in the load settlement entity providing the rate signal. This is a critical component that will encourage rate innovation by entities other than the distribution utilities that are required to provide default service.

III. Summary of NEM 3.0 Proposal

Q. Could you summarize your NEM 3.0 tariff proposal?

A. Yes, in general, it is structured to enable movement to a transactive energy[5] rate structure for distributed energy resources. The proposal addresses customer-generators that have the necessary interval metering to support temporal price signals and customer-generators with monthly meter reads. Here is an outline of the basic elements:

- Continue existing grandfathering for NEM 1.0 and 2.0 customer-generators through 12/31/40. Target 9/1/24 as the start of NEM 3.0 for new projects and extend grandfathering for NEM 3.0 tariffs through at least 12/31/45. Those projects > 100 kW with approved interconnections before 9/1/24, even if not yet under construction, would be grandfathered into NEM 2.0 terms but have the option, along with NEM 1.0 customer-generators to transition to NEM 3.0. Any project up to 100 kW with a complete interconnection application pending as of the 9/1/24 effective date would also be grandfathered to NEM 2.0 unless opting for NEM 3.0.

[5] "Transactive Energy" or "TE" is defined at RSA 374-F:2, XII as "a system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter." This would involve enabling DERs to respond to temporal price signals related to balancing supply and demand within capacity constraints.

- Answer "yes" to the question of whether "exports to the grid by customer-generators taking default service should be accounted for as reduction to what would otherwise be the wholesale load obligation of the load serving entity providing default service, absent such exports to the grid." This is required in order for entities other than the distribution utilities to provide net metering services. This will help resolve several other important issues to be addressed including "maximizing net benefits while minimizing negative costs shifts" as called for by RSA 362-A:9, XVI(a).
- For greater than 1 MW customer-generators answer "yes" to the question in RSA 362-A:9, XXIII of whether monetary credit for exports to the grid "should include compensation for services and value not currently compensated including avoided transmission and capacity costs." This is required in order to align benefits to those that created it consistent with proper rate making principles outlined by Bonbright and Kahn. This also relates to maximizing net benefits and avoiding a substantial negative cost shift from other customers to customer-generators and avoids unjust and unreasonable cost shifting.
- Answer "yes" to the question in RSA 362-A:9, XXIII as to whether the cost of compliance with the electric Renewable Portfolio Standard (RPS), including prior period reconciliations, should be excluded from the monetary credit for exports to the grid. The RPS obligation compliance costs are associated with the use of electricity, not the generation of electricity making it appropriate to be excluded from the compensation from the export of electricity. This helps resolve several issues including minimizing negative cost shifts and avoiding unjust and unreasonable cost shifts as called for by RSA 362-A:9, XVI(a).
- Continue the basic structure of NEM 2.0 for projects up to 100 kW, except apply a different credit rate for the energy supply component of compensation for net exports to the grid. This has been applied in the New Hampshire Electric Cooperative's service territory with little impact to the adoption rate of net metered system development.
- Enable energy storage to be interconnected in NEM 3.0 as a part of all new and existing NEM customer-generators that convert to NEM 3.0. This pertains to maximizing net benefits from net metering.
- If necessary, stage implementation of new rate structures and business processes to ease any administrative burden on distribution utilities. As an example, limiting NEM 3.0 rate

changes to only projects > 1 MW, which are limited in number at present, may prove to be an efficient way for distribution utilities to develop the business processes needed to develop the necessary price signals

IV. Grandfathering

Q. Why should existing customer-generators or approved NEM interconnections be grandfathered into their existing tariffs?

A. RSA 362-A:9, XV requires NEM 1.0 customer-generators to be grandfathered by stating that:

> Standard tariffs that are available to eligible customer-generators under this section shall terminate on December 31, 2040 and such customer-generators shall transition to tariffs that are in effect at that time.

This was enacted in May 2016, 23½ years before the termination date. In DE 16-576 in Order No. 26,029 (6/23/17) for NEM 2.0 the Commission adopted a common feature of the two settlements[6] providing that:

> 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;

and further noted that:

> 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.

This is good public policy and healthy for continued development and adoption of distributed energy resources as it provides predictability as to the terms and conditions of net metering going forward over a time period commensurate with the duration that the investment might be financed and relied upon.

In its 6/23/17 Order, the Commission also solicited comment on two previously unidentified issues related to grandfathering: 1) whether transferring ownership would affect grandfathering; and 2) “whether subsequent expansions of or modifications to DG systems would be entitled to net metering under the grandfathered tariff.” In Order No. 26,047 (8/18/17) the Commission answered yes to both questions, as did most, if not all parties, and

[6] Order No. 26,029 at 23 and 51.

provided parameters as to what extent expansion was allowed within grandfathers. The Commission noted another new issue that was raised by Joint Commentators as to whether customers on original net metering (NEM 1.0) could migrate to the new tariff and solicited additional comment from parties. With no objection by any party and with support from Eversource in Order 26,055 (9/18/17), the Commission appropriately authorized customer-generators to migrate from NEM 1.0 to 2.0, but not back.

CPCNH is not aware of any reason why any of these grandfathering and expansion policies should not continue to apply, except that going forward CPCNH proposes that both NEM 1.0 and NEM 2.0 customer-generators have the option of migrating forward to NEM 3.0 tariffs, and that the grandfathering period for NEM 3.0 tariffs extend to at least December 31, 2045, or about 21½ years from when an order might be issued.

Also, the 2017 Order referred to grandfathering based on reservation of a NEM capacity allocation or reservation of a position in the interconnection queue by 9/1/17. CPCNH recommends that this be updated. At the time, there was a statutory limit to the amount of net energy metering allowed and in order to reserve a place within the interconnection queue, applications needed to have been completed with certain milestones to be met to maintain that position. In its June 23, 2017 Order, the Commission waived limits on the amount of capacity that could be net metered pursuant to RSA 362-A:9 I, as the law allows, so the NEM capacity allocation is no longer applicable. Instead, the Coalition proposes that new large customer-generators be grandfathered if they have an approved interconnection agreement in effect, even if not constructed or operational yet. For pending interconnections up to 100 kW, a complete and filed interconnection application should be sufficient to be grandfathered.

Finally, we recommend a target start date for NEM 3.0 tariffs of September 1, 2024, giving sufficient notice to potential DG customers, developers, and installers of any changes in NEM tariffs, assuming an Order approving any tariff changes by June. We also recommend the applying the proviso from the June 23, 2017 Order (at 56) to NEM3.0;

> 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.

V. Accounting for Exports to the Grid

Q. Why should "exports to the grid by customer-generators taking default service be accounted for as reduction to what would otherwise be the wholesale load obligation of the load serving entity providing default service absent such exports to the grid" as RSA 362-A:9, XXI(a) directed the PUC to use its best efforts to consider by June 15, 2022?

A. There are numerous reasons why this is essential, starting with the need for utilities to comply with Puc 2205.15 Net Metering by CPAs, that echoes the requirements of RSA 362-A:9, II:

> Puc 2205.15 Net Metering by CPAs.
>
> (a) CPAs shall determine the terms, conditions, and prices under which they agree to provide generation supply to and credit, as an offset to supply, or purchase the generation output exported to the distribution system from CPA customers with customer-sited distributed generation.
>
> (b) Pursuant to RSA 362-A:9, II, such generation output shall be accounted for as a reduction to the CPA customers' electricity supplier's wholesale load obligation for energy supply as an LSE, net of any applicable line loss adjustments, as approved by the commission.

In related discussions from technical sessions in DE 23-063, the Joint Utilities' Petition for Waiver of Certain Provisions of the Puc 2200 Rules, the parties have discussed what may be necessary to enable CPAs to serve net metering customers. Negative usage data is critical to the ability of CPAs, as well as CEPS, to serve most net metered customers as it provides the value on which to base credits or compensation for their exports to the grid. Appropriately it is essential to have that same amount of negative usage credited as a load reduction to the load asset being used by the CPA or CEPS offering the net metering service as the energy being credited by the net metering program is helping to reduce the wholesale load needs by the CPA or CEPS. Power exported to the distribution grid in New Hampshire by net metered customer-generators reduces a comparable amount of power that is supplied over the high voltage transmission grid from the ISO-NE market bulk generators. Furthermore, and in alignment with the laws of physics, because DG offsets load that is most proximate to it on the distribution grid (i.e., it travels the path of least resistance), it experiences less line and voltage transformation losses than power delivered over the high-voltage transmission grid over a long distance.

If the DG is not registered as a "Generator" participant in the federal ISO-NE wholesale market, then the power it exports to the distribution grid functions as a load reducer relative to load seen on the transmission grid. As such, it should be accounted for as reducing the load for charges for electric energy supply, generation capacity, transmission capacity and operation, and ancillary services. Consistent with rate making principles it makes sense that the supplier purchasing power from the net metering customer should see the benefit from that purchase through a reduction in load being purchased through the wholesale markets.

It has been the policy of the State of New Hampshire since the original enactment of net metering a quarter of century ago, that competitive suppliers should be able to set their own terms, conditions, and rates for net metered generation supplied to the grid. It is also statutory policy to enable and promote customer and community choice of energy suppliers, those who arrange to offset or supply your load, from both local and regional resources, and inclusive of the option of interconnected self-generation. This is expected to spur innovation and cost savings for NH ratepayers. It is clearly **not** the policy of this state, and indeed is inimical to our State Constitution, that net metered electric generation and the development and compensation of distributed energy resources should be a monopoly of the regulated utilities. Ensuring non-discriminatory open access to the electric system for wholesale and retail transactions is of paramount importance. CEPS and CPAs need to be able to receive their fair share of supply credit for their customer-generator's output in an accurate and timely manner. Currently, those exports to the grid are accounted for and reported as zero loads, not negative loads, in the load settlement process, creating a disconnect in the "but for" for causation principle.

However, before the distribution utilities can come into compliance with RSA 362-A:9, II and Puc 2205.15, the Commission first needs to approve any applicable line loss adjustments to factor into the net load reduction relative ISO-NE load obligation. CPCNH intends to soon file with other interested parties a petition requesting an adjudicated proceeding for such an approval and the tariff changes necessary to implement load settlement for suppliers that takes into account exports to grid by their customer generators.

Q. How does this relate to this docket?

A. The direct nexus with this docket arises from the fact that in our discussions with the Joint Utilities and other parties about the load settlement process and how it would need to change to allow CPAs to account for NEM exports to the grid, Eversource representatives indicated that changing this process would necessitate changing the load settlement process for all suppliers, including CEPS, and default service suppliers. We concur. This change would also result in more just and reasonable rates for default service customers because presently, the load reduction benefit of unaccounted for DG is socialized to all load in an obscure and non-transparent calculation where it is of limited benefit to customers. This reduction of this "residual" calculation to balance the difference between the wholesale meter reads (at the tie or substation interconnection between distribution and transmission) and retail meter reads for each hour of the year should be welcomed by all parties. Absent NEM DG, the difference between these two readings would be mainly attributable to line losses, on average perhaps, close to the published line loss rates. However, with all the unaccounted-for energy from NEM DG, the Joint Utilities concede that the apparent difference between these two could go negative at some hours of the day;[7] meaning that it may appear that it requires the purchase of less than 1 MW of ISO-NE power to supply more than 1 MW of retail load, when normally it might require 1.07 MW of ISO-NE power to supply 1 MW of retail load due to line losses.

Part of this distortion may arise from the lack of utility data on how net metered DG affects the load/production profile of customer-generators. Discovery has helped to point out that the distribution utilities do not have load profile research on net metered customers[8] except, perhaps, the hourly load data compiled for response to data requests. As a result, customers with monthly net exports to the grid contribute to a reduction of the load settlement profile of all suppliers with a scale down of all hours of load (24 hours / 7 days a week), by the class average load shape. This process ignores the fact that some hours for that customer actually have consumption (e.g. after dark for PV) and others have net exports. This process distorts the load profile of the utility default service provider from reality and compared with other suppliers who

[7] DR CPCNH 2-002 Attachment 5(a)-Eversource Data Response and 5(b) Liberty-DR
[8] DR OCA 2-014, Attachment 6(a)-Eversource, OCA 3-12 Attachment 6(b)-Liberty, Attachment 6(c)-Unitil

have few if any “0” monthly load NEM customers. The rate effects of this on all ratepayers is simply not clear.

Q. What additional benefits can come from this approach?

A. Treating exports to the grid by default service customer-generators as load reductions to the supplier’s ISO-NE load obligation has an additional advantage because it enables a new approach to compensation for default service generation supply that can minimize negative cost shifts and maximize net benefits from NEM 3.0 as described below under VII.

In order to treat such exports to the grid as load reducers, generators that are selling the same power into the ISO-NE market should retire from that market first. This process is straight forward for Settlement Only Generators (SOG). Generators that wish to net meter and have capacity supply obligations to the region would need to first fulfill or unwind those obligations. This process is also straightforward as generators can participate in monthly or annual capacity reconciliation auctions or sell their obligation to parties that are able to fulfill it. Only a relatively few customer-generators are registered with ISO-NE as market participants. For Liberty, none of its 1,456 NEM customers are ISO-NE market participants. Only two are with Unitil, out of about 1,980 operating customer-generators. However, Eversource “holds 49 ISO-NE asset ID numbers for which the Company receives generation and capacity only payments” out of about 13,000 customer-generators. This seems to include most of the largest customer-generators, including about 10 hydroelectric facilities, that sold their output and capacity into the ISO-NE market as QFs before net metering as municipal group hosts These generators have assigned their revenue from energy and capacity payments to Eversource in return for the ability to net meter as a group host. Eversource has made clear that they do not require customer-generators to sell their power and capacity in the ISO-NE markets.[9]

CPCNH requested 2½ years of aggregated hourly export data for all 209 customer-generators that Eversource has interval data for in August 2023. Eversource was not able to meet the request but provided aggregated 2022 data for the seven customer-generators over 1 MW and a sample of 10 hydroelectric and 10 PV systems that are market participants. I matched that data up against the date and hour for each month that Regional Network Service (RNS) charges were incurred at ~$11.90/kW-mo, to estimate the amount of RNS charges for Eversource

[9] DR CPCNH 2-003, Attachment 7

customers that would have been avoided had they these customer-generators been retired fromthe ISO-NE markets and instead were treated as load reducers without accounting for line loss adjustments. Excerpts from that spreadsheet analysis, that included a total of 10 NEM production profiles, including all the summary data, is attached as Attachment 6. For the seven largest systems over 1 MW, the avoided RNS charges in 2022 would have totaled about $787,000 or the equivalent of about 1.67¢/kWh. There are another 42 systems not treated as load reducers that could realize this level of additional avoided cost value by retiring from the ISO-NE markets. There are a total of 10 PV systems, 1 gas (presumably, landfill methane), and 38 hydroelectric systems in this group. Adding the avoided Local Network Service (LNS) charges of about $1.63/kW-mo. would increase the avoided transmission costs from the seven largest systems to about $900,000. However, it should be noted that since Eversource's LNS revenue requirement is specific to its "local" transmission system in New Hampshire only, accounted for separately from their LNS in Massachusetts and Connecticut, most of any reduction in LNS charges would reappear as part of the true-up of the LNS revenue requirement. It should be noted that this load reduction would also free up peak capacity for more beneficial electrification load, such as from electric vehicles and heat pumps, likely increasing this avoided cost value.

In Unitil's and Liberty's case however, their LNS load is a relatively small share of the total LNS load, and most of any cost savings that may rebound in future increased rate will shift away from their system and customers. In Liberty's specific case, as with RNS, to out-of-state transmission customers (because National Grid is their LNS provider and most of the other transmission customer load is in Massachusetts and Rhode Island). Although all transmission customers pay the same RNS rate, LNS rates vary by provider. In late 2022, Liberty's LNS rate was about $3.00/kW-mo. adding about 25% in cost savings to the avoided RNS rates and this year is $3.58/kW-mo.

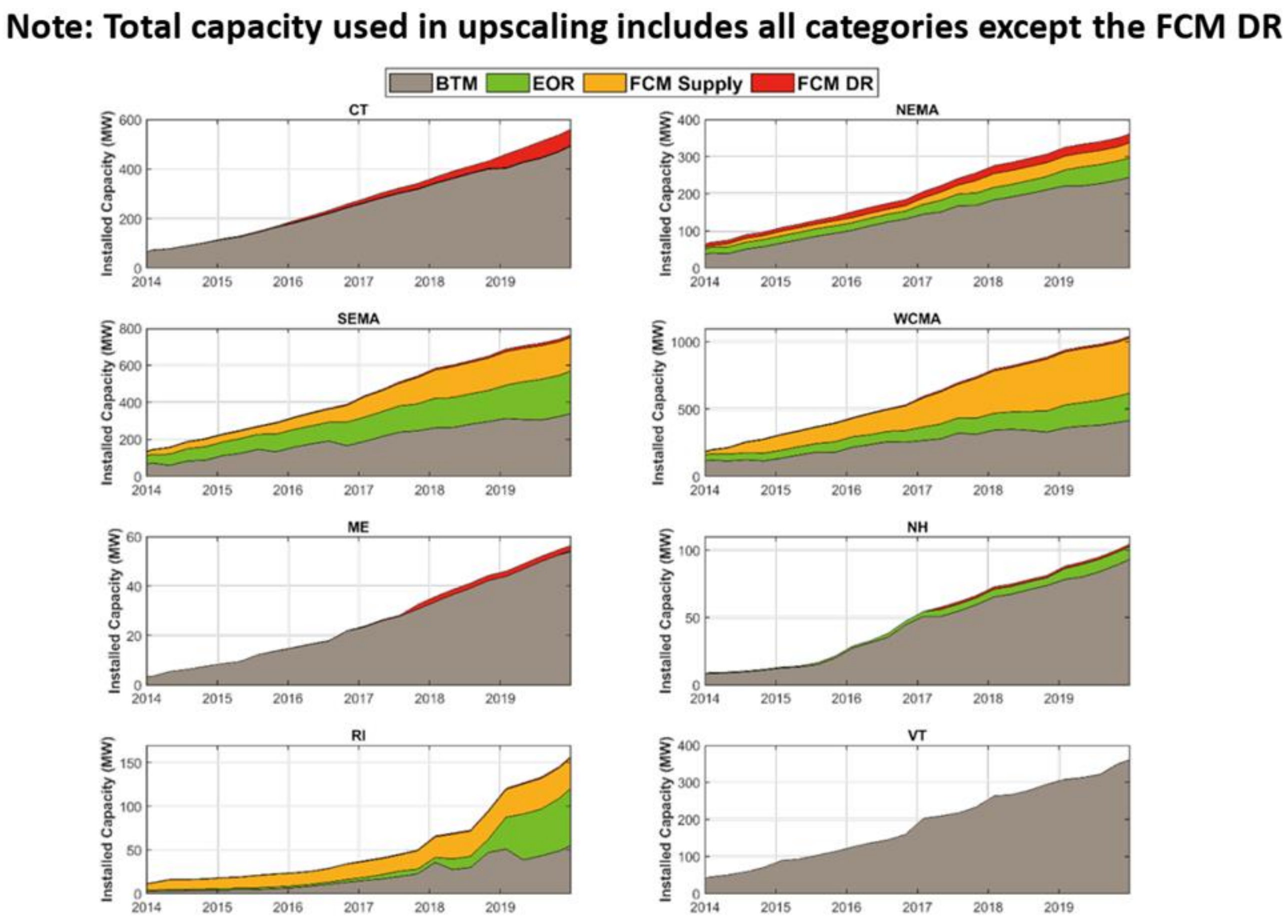
The NH Department of Energy commissioned Value of Distributed Energy Resources (VDER) Study (10/31/22) concluded that "[f]rom a utility system perspective, under current

ISO-NE market rules, all systems provide greater value by passively reducing load than by participating as aggregated resources in the [ISO-NE] markets, …"[10]

Note the following graphic from ISO-NE's 2020 Behind-the-Meter (BTM) Solar Photovoltaic (PV) data documentation that shows the proportions of BTM PV capacity in-state that functions as a load reducer (gray shading) vs. market participant (green, gold and red wedges). (Also, note the scale is different for different states.) Vermont is the one state that has no or virtually no DG participating in ISO-NE markets because Vermont utilities, stakeholders and PUC determined back in 2009 that the greatest value was produced for Vermont ratepayers by treating all such resources as load reducers rather than selling their output and capacity through the ISO-NE markets. Vermont also asserted that such DG would also reduce RNS charges to Vermont, before ISO-NE and FERC amended the OATT to clarify that that is in fact the case.[11]

[10] "…with the single exception of micro hydro facilities. Micro hydro plants are able to consistently generate energy during the summer and winter peak reliability periods, thereby increasing their value in the [ISO-NE] capacity market New Hampshire Value of Distributed Energy Resources Final Report, p.59 (under "Key Findings"). Note, however, that if NEM 3.0 could provide credit for actual avoided capacity costs, along with actual avoided transmission costs, to micro-hydro (small systems that don't normally have interval metering), then micro-hydro could provide greater value as load reducers along with all other distributed generation and storage technologies than as ISO-NE federal wholesale market participants.

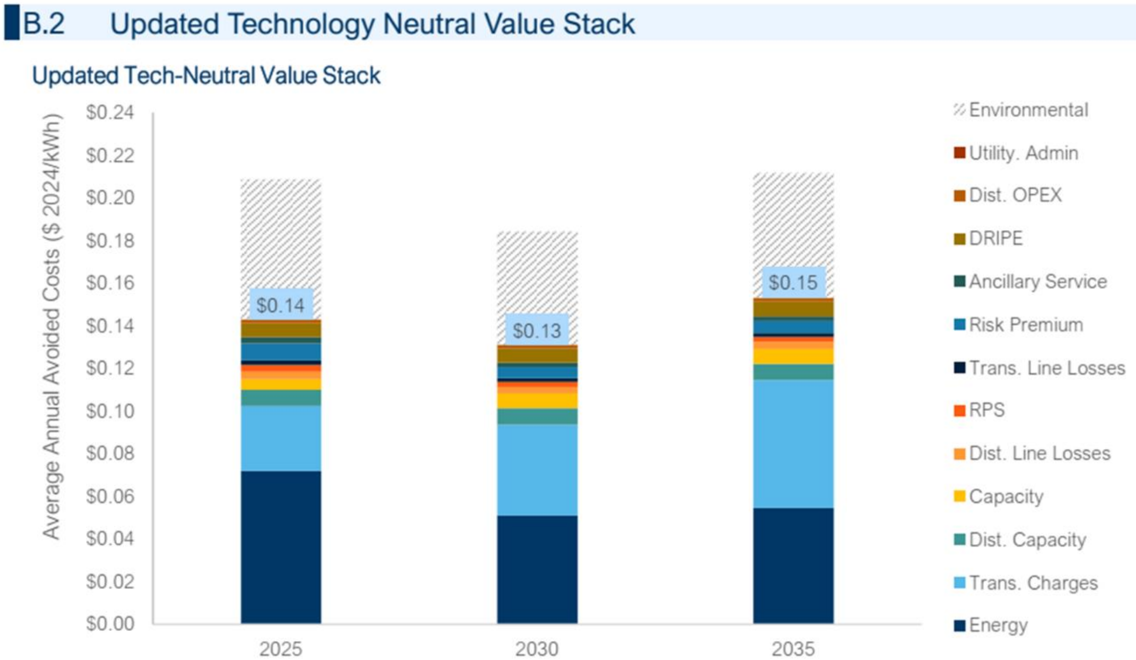
[11] Vermont Public Service Board, Docket No. 7533, Investigation Re: Establishment of a Standard Offer Program for Qualifying Sustainably Priced Energy Enterprise Development ("SPEED") Resources, Order Establishing a Standard-Offer Program For Qualifying Speed Resources,



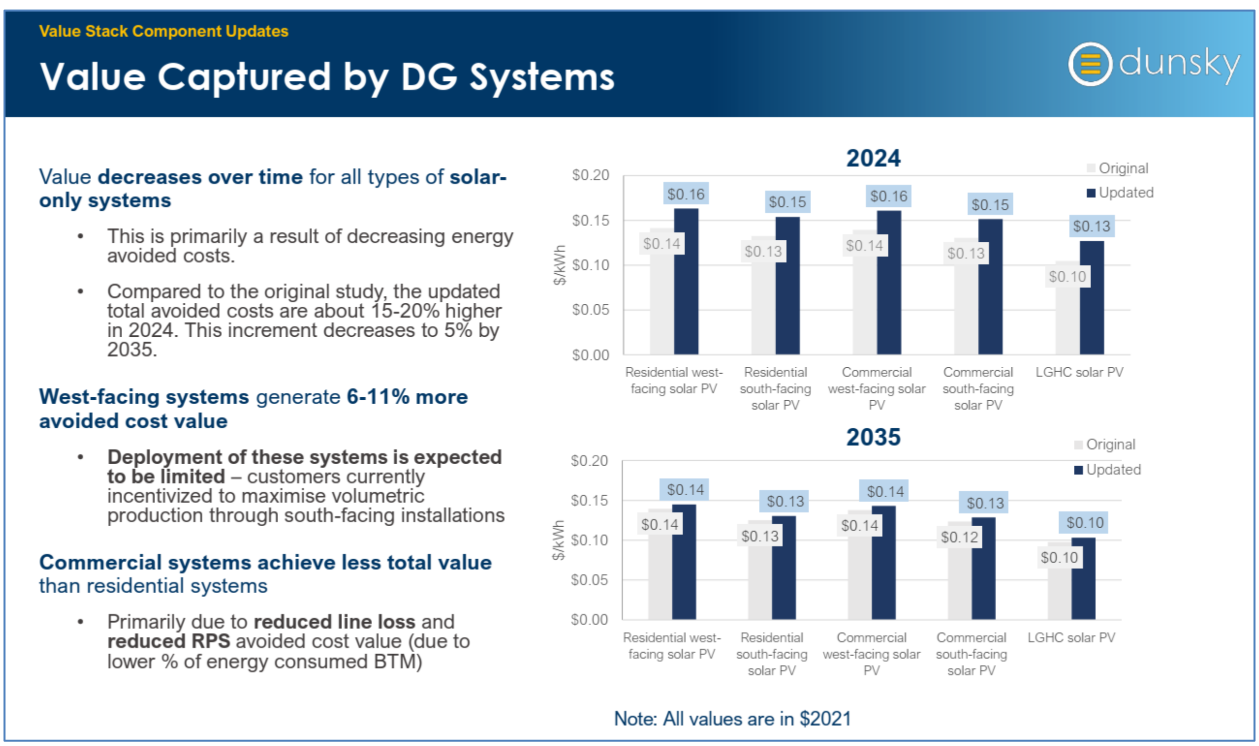
VI. Compensation for Avoided Transmission Costs

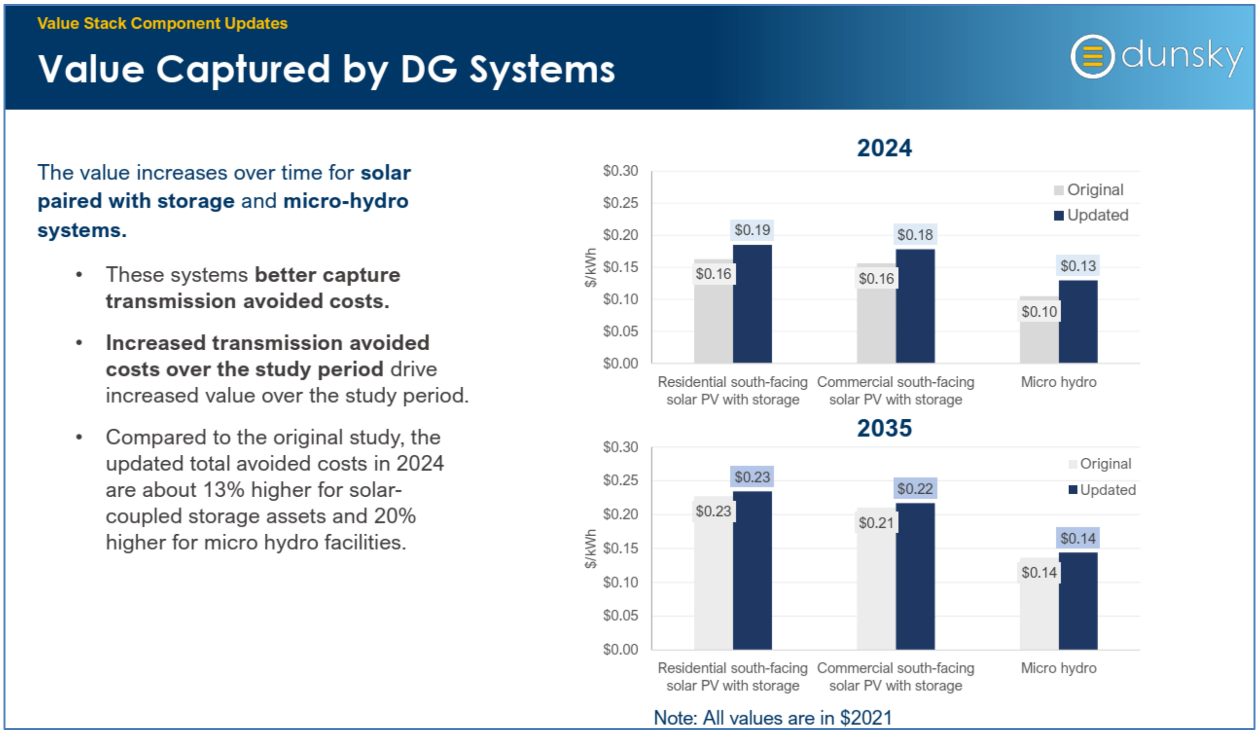
Q. For customer-generators greater than 1 MW, why should monetary credit for exports to the grid include compensation for services and value not currently compensated including avoided transmission" costs as RSA 362-A:9, XXIII directs the Commission to consider in this docket?

A. As the VDER study found, much of the value of DG (and distributed energy storage) functioning as a load reducer is realized by reducing transmission costs charged to NH ratepayers. For example, the VDER study update from this spring includes the following graphic labeled "B.2" that shows the value of reduced transmission charges for a technology-neutral generator, essentially a generator with uniform output 24/7, 365, like the #10 Landfill Gas generator hypothetical in my avoided Transmission Cost Rate Model:



The study also noted that certain DG, such as western-facing PV systems, or PV coupled with battery storage, can produce more value from avoided transmission (and capacity charges) than other systems, as illustrated in the following two slides from the Dunsky team's 4/20/23 NH VDER Stakeholder Presentation:





It is logical, and consistent with cost causation principles and the considerations in RSA 362-A:9, XVI(a) of: "balancing the interests of customer-generators with those of electric utility ratepayers by maximizing any net benefits while minimizing any negative cost shifts from customer-generators to other customers and from other customers to customer-generators" that those customer-generators that create quantifiable cost reductions be compensated for such reductions. Because periods of coincident peak can be correlated with high electricity prices in the day ahead and real time markets, due to the fact that the bid stack and clearing price for generation tends to get steeper with the dispatch of higher cost generation (i.e, the supply curve). If demand reduction occurs here, it tends to result in greater demand reduction-induced price effect (DRIPE) that benefits all ratepayers.

Q. What is your proposal for compensating customer-generators for avoided transmission costs that they cause?

A. For customer-generators with interval metering I propose they be compensated for actual avoided RNS charges and an appropriate portion of avoided LNS charges, calculated in a similar manner as Unitil proposed for their Kingston single-axis solar tracker project in DE 22-073, which was supported by the DOE, OCA, CENH, and approved by the PUC. The compensation to such customer-generators would be made in arrears after all relevant meter data and charges are known and would be charged to the Transmission Cost Adjustment Mechanism (TCAM) for recovery from all load charged for transmission. Because the sum of actual and avoided transmission charges would be approximately the same as actual transmission charges, absent ("but for") the exports to the grid at coincident system peaks by such customer-generators, other ratepayers would be neutral as to the overall rate impact, minimizing any cost shifting for transmission costs.

Q. Would you recommend any compensation for avoided transmission costs for customer-generators > 100 kW up to 1 MW that don't have interval metering?

A. Yes, those customer-generators should not be disadvantaged because the distribution utility has not provided them with interval metering. Using the best reasonably available data for estimating hourly production by such DG, an estimated average benefit from avoided transmission costs should be calculated annually and adjusted along with the annual adjustment of transmission charges. For the 10 different production profiles I analyzed, the value per kWh of avoided transmission costs all generally aligned in the range of 0.95¢/kWh to 1.75¢/kWh with many around 1.5 or 1.6¢/kWh, which is roughly one half of current transmission charges per kWh that range from 2.17¢ (Liberty G-2) and 2.28¢ (Liberty G-3) to 2.965¢ for Eversource Rate R, Standard Residential Service, and 3.09¢ for Unitil (all rate classes) and to 3.334¢ for Liberty Rate D.

VII. Compensation for Avoided Capacity Costs to LSEs from Customer-Generators.

Q. Why and how should customer generators be compensated for avoided capacity costs, particularly those over 1 MW in rated interconnection?

A. As with energy, ancillary services, and transmission cost allocation, ISO-NE tariffs and policies recognize DG and DS, if not participating in ISO-NE markets, as load reducers relative to capacity load obligations. To the extent that they export power to the distribution grid at the annual hour of coincident peak demand on which the next power year's capacity load obligations are allocated, they reduce the overall metering domains annual coincident peak demand.

When such a generator is on utility default service and is compensated for their exports to the grid based on the applicable default energy service rate, then that rate has embedded with it, credit for coincident peak demand and no further compensation is necessary. However, when such a customer-generator is on competitive or CPA energy service, their supplier can only afford to compensate them for such capacity load obligation reduction, if the supplier load asset has been reduced by the coincident peak load reduction.

Capacity load obligations are tracked by load asset, and since under our NEM 3.0 proposal, both positive and negative loads would be settled by load asset for all suppliers, allocation of the overall metering domain's coincident peak contribution to each load asset for its net load at the annual hour of coincident peak demand is appropriate. That net coincident peak contribution can then be allocated to each individual customer in proportion to their individual positive demand, based on either interval metered load or estimated load using class average load shape with those exporting to the grid at system peak still receiving zero capacity tags. For those customer-generators exporting to the grid without interval meters, their contribution to the reduction in load asset's net coincident peak contribution would be estimated using load/production profiles, based on the best readily available data, such as from customer-generators with interval meters or ISO-NE's reconstituted hourly production profile for BTM PV in New Hampshire.

This would also be more equitable for utility default service customers as they, as a group, would share in the credit for those utility default service customer-generators that contributed to the reduction in that load asset's net coincident peak contribution, since the compensation for such capacity reduction would come from default service customers as described in the next section.

VIII. Excluding RPS Compliance Costs from Utility Default Service Supply Credit

Q. Why should the RPS Compliance Costs, including for prior period reconciliations, be excluded from the utility default service supply credit for exports to the grid by customer-generators on utility default service?

A. RPS Compliance costs are based on the use of energy, not the production of energy. There is no basis for crediting production the benefit of RPS compliance costs as exports do not reduce the amount of energy use that RPS compliance costs are calculated from. Additionally, some net metered systems receive Renewable Energy Certificate (REC)s for their production, resulting in a duplicative benefit. This is also the primary step needed to adjust the utility default service supply credit down to a level where it more closely matches the value produced of NEM exports to grid as load reducers and so can be recovered from within default service rates as described below, eliminating the need for any cost shifting of the energy supply credit, which is the bulk of the compensation given to utility default service customer-generators for their exports to the grid.

Q. Can you illustrate the unreasonable cost shift and how this can result in duplicate compensation for NEM 2.0 customer-generators?

A. Yes, for instance, consider a hypothetical NEM 2.0 customer-generator that consumes 10,000 kWh per year and also has PV that produces the same amount of power but does so mostly in the half of the year with the longest days (summer) when they are a net exporter of 3,000 kWh and during the winter half of the year, they are a net consumer of 3,000 kWh. For illustrative purposes, say the default service rate is 10¢/kWh and the cost of RPS compliance embedded in that rate is 0.8¢/kWh, so over the course of the summer months they get $300 in bill credits and are charged $300 over the course of winter months. After the end of year, they have paid nothing for their energy supply but have created an RPS compliance obligation for the 3,000 kWh in electricity deliveries, which costs the utility $24 (3,000 kWh x $0.08) which they have to recover from other ratepayers. At the same time, the customer-generator can sell 10 RECs for their total production to the utility, say at $30/REC would be $300, so while benefiting from the existence of RPS, they pay nothing for their own RPS compliance costs, while shifting that cost to other ratepayers.

While in this example, the overall "missing money" problem for not contributing to RPS compliance is relatively small, it becomes more significant at scale. For example, Eversource indicated in discovery[12] that it compensated some 83,110,444 kWh in exports to the grid from NEM 2.0 customer-generators between 2018 and August 2023. The cost of RPS compliance shifted from those customer-generators to mostly other customers, assuming an RPS compliance cost of about $0.008/kWh, adds up about $665,000 over 6 years or roughly $100,000/yr For Unitil, between January 2020 through June 2023, NEM 2.0 customers exported some 52,243,426 kWh to grid. At $0.008/kWh, the cost of RPS compliance cost shift in that compensation would be about $418,000 or ~$120,000/yr. \

[12] DR Eversource Attachment CPCNH 1-003, Attachment 8

Q. What is your proposal for adjusting the default service energy supply rate so that it could be recovered from default service customers without increasing the rates they would otherwise pay without any change for default service, while reducing what they would otherwise pay in Stranded Cost Recovery Charges?

A. The bulk of the difference between the full default service rate and what the supplier is paid is mainly the cost of RPS compliance. There are a few other typically minor charges and credits that make up the difference, consisting of charges for the cost of administering default service, inclusion of working capital, plus prior period reconciliation of each of the elements in the default service rate for under and over collections. The two tables on the next page from Eversource's June 2023 default service filing illustrate this. The first is for the large customer group, where a rate that changes each month applies and is reasonably typical. The second is for the small customer group, which is unusual in that there is a very large prior period credit that reduces the customer rate below what the supplier is paid.

The yellow highlighted line # 4 is the Base Default Service Rate, which is the rate that must be charged to customers to cover the supplier's fixed price all-requirements price (all load that shows up). It is a bit larger than what is actually paid to the supplier to account for line losses between the retail meter and PTF boundary in the NH load zone where the supplier prices their supply offer. That amount and the assumed line losses are redacted and treated as competitively sensitive commercial information. Lines 7 and 8 are the estimated RPS compliance costs for the period ($0.00834/kWh) and the prior period reconciliation adjustment factor of a credit of $0.00607, which is unusually large, as is line 6. For the small customer group, there are two unusually large prior period over collection credits resulting in a retail default service rate that is lower than the Base Energy Service Rate.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE DBA EVERSOURCE ENERGY
ENERGY SERVICE RATE SETTING AUGUST 1, 2023 THROUGH JANUARY 31, 2024
LARGE CUSTOMERS (RATES LG AND GV)

Line	Large C&I (Rate LG & GV) Monthly Energy Service Rate Calculation	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24
1	Forecast Large C&I Wholesale Energy Service Load (MWhs)	20,932	16,455	15,983	16,920	20,492	21,321
2	Loss Factor	[redacted]					
3	Forecast Large C&I Retail Energy Service Load (MWhs)						
4	Wholesale Contract Price ($/MWh)	[redacted]					
5	Base Large C&I Energy Service Rate ($/kWh)	$ 0.09405	$ 0.07302	$ 0.07054	$ 0.11172	$ 0.20256	$ 0.26793
6	Energy Service Reconciliation Adjustment Factor ($/kWh)	$ 0.02099	$ 0.02099	$ 0.02099	$ 0.02099	$ 0.02099	$ 0.02099
7	Renewable Portfolio Standard Adjustment Factor ($/kWh)	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834
8	Renewable Portfolio Standard Reconciliation Adjustment Factor ($/kWh)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)
9	A&G Adjustment Factor ($/kWh)	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066
10	Large Customer Working Capital Adjustment Factor ($/kWh)	$ 0.00041	$ 0.00041	$ 0.00041	$ 0.00041	$ 0.00041	$ 0.00041
11	Total Large C&I Monthly Energy Service Rates ($/kWh)	$ 0.11837	$ 0.09734	$ 0.09486	$ 0.13604	$ 0.22688	$ 0.29225

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE DBA EVERSOURCE ENERGY
ENERGY SERVICE RATE SETTING AUGUST 1, 2023 THROUGH JANUARY 31, 2024
SMALL CUSTOMERS (RATES R, G AND OL)

Line	Small Customers (Rate R, G, & OL) Weighted Average Energy Service Rate Calculation	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	6 Month Total
1	Forecast Small Customer Wholesale Energy Service Load (MWhs)	331,769	260,801	253,323	268,179	324,789	337,928	1,776,789
2	Loss Factor	[redacted]						
3	Forecast Small Customer Retail Energy Service Load (MWhs)							
4	Wholesale Contract Price ($/MWh)	[redacted]						
5	Base Small Customer Energy Service Rate ($/kWh)	$ 0.09255	$ 0.07343	$ 0.06958	$ 0.10390	$ 0.18146	$ 0.23646	
6	Energy Service Reconciliation Adjustment Factor ($/kWh)	$ (0.00849)	$ (0.00849)	$ (0.00849)	$ (0.00849)	$ (0.00849)	$ (0.00849)	
7	Renewable Portfolio Standard Adjustment Factor ($/kWh)	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	
8	Renewable Portfolio Standard Reconciliation Adjustment Factor ($/kWh)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	$ (0.00607)	
9	A&G Adjustment Factor ($/kWh)	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	$ 0.00066	
10	Small Customer Working Capital Adjustment Factor ($/kWh)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	
11	Total Small Customer Monthly Calculated Energy Service Rate ($/kWh)	$ 0.08657	$ 0.06745	$ 0.06360	$ 0.09792	$ 0.17548	$ 0.23048	
12	Forecast Small Customer Total Energy Service Cost, including Working Capital Requirement	[redacted]						$ 207,463,902
13	**Weighted Average Small Customer Energy Service Rate for the Period August 1, 2023 through January 31, 2024 ($/kWh)**							**$ 0.12582**

My proposal is that Default Energy Service Supply Rate for all NEM 3.0 customers would be based on the Base Energy Service Rate, discounted for the modest line losses that occur on the distribution grid between the point of export and the load it offsets (~2% to 3%). Under NEM 2.0, these exports are treated as zero load and do not reduce the amount of load the supplier must supply from the ISO-NE market. If these exports to grid are treated as reductions to the supplier's load obligation, then instead of paying the supplier for those kWh, the exporting customer-generators can be paid the same equivalent price (Base Energy Service Rate with an appropriate loss factor) as the supplier is paid, , eliminating the need to recover it through a stranded cost recovery charge.

To illustrate this scenario, consider that a group of default service customers consumes 1 million kWh in a given month and default service customer-generators export 100,000 kWh to grid during the same month. Currently, the default service supplier is paid for 1 million kWh at a given rate. Under this NEM 3.0 proposal, that supplier would only have to purchase 900,000 kWh and would be paid for that, while the remaining 100,000 kWh would come from customer-generators who would be paid an equivalent price (recognizing lower line losses for that supply), so that the consuming customers pay the same overall amount. This market-based rate eliminates the need to recover net metered exports through the stranded cost recovery charge and any cost shifting related to energy service supply credits.

IX. NEM 3.0 for up to 100 kW.

Q. Do you have a position on NEM 3.0 for systems up to 100 kW?

A. Yes, mainly that the basic structure of NEM 2.0 is continued, except that there would be a different credit rate for the energy supply component of compensation for net exports to the grid as described above. While I have not had to time to evaluate the distribution credit, my observation is that the VDER study found that there are some unrecognized avoided costs. Logically, there might be a greater credit for avoided distribution costs for NEM DG and DS under 100 kW than for larger systems, because they will offset load very nearby compared with most larger systems where the energy will typically travel further to offsets loads downstream and upstream, so it is possible that widespread smaller systems will free up more distribution capacity to support increased loads from beneficial electrification such as for electric vehicles and heat pumps. As Unitil pointed out in DE 22-073 "…each component of the utility distribution system contributes to electricity line losses and the amount of losses depends on the distance from the source to the load. Generally speaking, the longer the distance over which electricity is transmitted, the more electricity is lost."[13]

Where TOU rates are available, especially three-part TOU rates, CPCNH encourages the Commission to direct the utilities to enable export credit by TOU period and ensure that competitive suppliers and CPAs can also credit exports for energy service by TOU period as differential import and export rates.

X. Storage

Q. Why do you think the Commission can or should enable battery energy storage as part of NEM 3.0 tariffs?

A. First, the NH legislature enacted Chapter 243:8, NH Laws of 2023 (SB 166), effective 10/7/23, to amend RSA 374-H:2, I to read as follows, with new text in bold italics:

> I. The commission shall adopt rules ***or approve tariffs*** clarifying policy for the installation, interconnection, and use of energy storage systems by customers of utilities, and shall incorporate the following principles into the rules ***or approved tariffs***:

Thus, the Commission can enable energy storage systems through tariffs, such as a NEM 3.0 tariff, consistent with the cited principles. We propose that at this time, energy storage systems only be enabled in conjunction with DG as a part of NEM, and that stand-alone energy storage systems should be considered in a subsequent proceeding. The reason to do this is to improve the value proposition of NEM 3.0 in conjunction with the strong temporal price signal of being able to get credit for actual avoided costs at times of coincident peak demand, as well as potentially avoided generation capacity costs if served by a CPA or CEPS. This would help drive innovation and better solutions for steep ramp rates related to variable renewable energy resources. For example, fixed-orientation PV combined with storage could compete with single and dual axis PV tracker systems, with or without storage, for the investment that produces the most value for the least cost. Excess production around solar noon could be captured and stored for release later in the afternoon and evening to reduce peak demand,

[13] Testimony of Jacob S. Dusling for Unitil at 20.

creating more capacity for beneficial electrification without the need for costly new investments to serve growing peak demand. This will help maximize net benefits from net metering.

Q. What provisions should the Commission consider for interconnecting DS with DG in NEM tariffs (or rules eventually if desired)?

A. An important one would be from the Interstate Renewable Energy Council's (IREC) Model Interconnection Procedures, 2023 Edition, which allows the maximum export to be constrained to an agreed upon interconnection limit that is less than the sum of the potential export of each system if operated separately. The IREC model interconnection procedures were developed this way with the intention that storage could be added to existing NEM systems without increasing the interconnection rating as the battery would only discharge when DG is operating at less than full capacity or not at all. Below are those model procedures that the Commission could direct the utilities to adapt and incorporate into the interconnection standards by reference through their tariffs:

> **B. Limited-Export and Non-Exporting DERs**
> 1. If a DER uses any configuration or operating mode in Section IV.B.3 to limit the export of electrical power across the Point of Common Coupling, then the Export Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export from a DER must comply with the limits identified in this Section. The Export Capacity specified by the Interconnection Customer in the Application will subsequently be included as a limitation in the Interconnection Agreement.
> 2. An Application proposing to use a configuration or operating mode to limit the export of electrical power across the Point of Common Coupling shall include proposed control and/or protection settings.
> 3. Acceptable methods of export limitation include:
>
> a. ***Export Limitation Methods for Non-Exporting DERs***: . . .
>
> b**. *Export Limitation Methods for Limited-Export DERs:***
>
> i. Directional Power Protection (Device 32): To limit export of power across the Point of Common Coupling, a directional power Protective Function is implemented using a utility-grade protective relay. The default setting for this Protective Function shall be the Export Capacity value, with a maximum 2.0 second time delay to limit Inadvertent Export.
>
> ii. Configured Power Rating: A reduced output rating utilizing the Power Rating Configuration Setting may be used to ensure the DER does not generate power beyond a certain value lower than the Nameplate Rating. The configuration setting corresponds to the active or apparent power ratings in

Table 28 of IEEE Std 1547-2018, as described in subclause 10.4. A local DER communication interface is not required to utilize the configuration setting as long as it can beset by other Certified means. The reduced power rating may be indicated by means of a Nameplate Rating replacement, or a supplemental adhesive derating tag to indicate the reduced power rating. This method must be Certified to IEEE Std 1547.1-2020. Use of a configured power rating not applied to individual generator(s) shall require evaluation under mutually agreed upon means.

c. Export Limitation Methods for Non-Exporting DERs or Limited-Export DERs:

i. Certified Power Control Systems: A DER may use Certified Power Control Systems to limit export. A DER utilizing this option must use a Power Control System and an inverter Certified per UL 1741 by a Nationally Recognized Testing Laboratory (NRTL) with a maximum open loop response time of no more than 30 seconds to limit Inadvertent Export.28 This option is not available for interconnections to Area Networks or Spot Networks.

ii. Agreed-Upon Means: A DER may be designed with other control systems and/or Protective Functions to limit export and Inadvertent Export if mutual agreement is reached with the Utility. The limits may be based on technical limitations of the Interconnection Customer's equipment or the Electric Delivery System equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the Interconnection Customer may use an uncertified Power Control System, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the Utility.

XI. Implementation Issues & Schedule

Q. What are the implications for utilities' administrative processes required to implement this NEM 3.0 proposal and related regulatory mechanisms?

A. The implications for these processes appear to be manageable, though it has been suggested by the distribution utilities that it would require time to implement allocation of load settlement and coincident peak contribution. In the last proceeding, the utilities proposed to implement a differential credit rate for the distribution rate component. In effect, this would result in a similar application for energy service and transmission for customer-generators over 100 kW. The fixed rate could be adjusted annually as part of the annual TCAM filing. The individual calculation for actual avoided transmission credit for large customer-generators is simple enough and could initially be done manually, if necessary and perhaps only quarterly or annually until automated, because the universe of customer-generators that this would apply to is not large,[14] even if interval-metered customer-generators on NEM 2.0 migrated to NEM 3.0. For automation, it would involve looking up a specific meter read for the monthly hour of coincident peak demand in a meter database and applying a uniform rate to any exported meter read for that hour. This would involve modifications to the billing system to fully automate, but not unlike what was done for the distribution rate credit.

To the extent some of these changes may take some time to fully implement, they could be phased in after the NEM 3.0 adoption date with new customer-generators served by NEM 2.0 terms until the new features are ready for use or initially limited to large projects, such as those over 1 MW in rated capacity.

Considering the large and growing number of NEM interconnection requests, such an approach could deliver significant net value by providing better price signals to incentivize DG and DS that target output at coincident peak demands helping leverage private investment to reduce impacts on the distributions system.

XII. Other Issues

Q. What other issues does the Commission need to consider in this docket that you want to address?

A. Time-based rates, as referenced in RSA 362-A:9, XVI(a) for consideration by the Commission, would be implemented to a very significant extent by the temporal price signal on actual avoided transmission costs available to customer-generators with interval metering, as well as through access to TOU rates for smaller systems referenced under IX above. Enabling CPAs to serve NEM customer-generators by receiving credit for their exports to the grid in load settlement and in reducing coincident peak contributions for capacity supply obligations would enable CPAs and CEPS to couple strong marginal price signals on generation and transmission costs with dynamic energy pricing options based on day-ahead the real-time prices and could unlock market-based innovation.

[14] In Eversource's territory, there are only about 209 such customers and in Liberty's territory, there are only 52 such customers.

Maximizing net benefits in the manner described in this NEM 3.0 proposal, would obviate any need to limit “the amount of generating capacity eligible for such tariffs” or impose a limit on “the size of facilities eligible to receive net metering tariffs.”

XIII. Conclusion

Q. Does that conclude your testimony?

A. Yes, it does. Thank for your attention and interest.

Attachments
To
Direct Testimony of Clifton Below

Attachment 1	Background Statement of Clifton Below, 11/23
Attachment 2	Annotated NH Net Energy Metering Statute, RSA 362-F:9
Attachment 3	List of CPCNH Member Communities as of 11/30/23
Attachment 4	Avoided Transmission Cost Rate Model by CB (excerpts)
Attachment 5	DR CPCNH 2-002 by Eversource (a) and Liberty (b)
Attachment 6	DR OCA 2-014 by Eversource (a), DR 3-12 by Liberty (b) and Unitil (c)
Attachment 7	DR CPCNH 2-003 by Eversource
Attachment 8	DR Eversource Attachment CPCNH 1-003

CLIFTON C. BELOW

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BACKGROUND & EXPERIENCE

CURRENT WORK

- **Managing General Partner of One Court Street Associates**, 1985-present (reduced responsibilities and activity, 2006-2/2012), responsible as a sweat equity partner for the development and ongoing management of One Court Street, a commercial building in downtown Lebanon that is home to Three Tomatoes Trattoria, Scratch Supply Company and various other businesses and medical offices including Osher Lifelong Learning Institute at Dartmouth College.
- **Vice President, Ardent Realty Services, Ltd,** 1992-present (with greatly reduced direct activity 2006-2/2012 while a PUC Commissioner), provides ongoing property management services to One Court Street Associates including marketing and showing of available space, lease negotiations and preparation, design and execution of tenant fit-outs, property management (including vendor and tenant relations), bookkeeping, accounting, tax return preparation, and odds & ends from fixing leaks to shoveling snow.
- **Lebanon City Councilor,** March 2015-present, **Assistant Mayor,** March 2019-present, and member, Lebanon Energy Advisory Committee (LEAC) (2015-present, **Chair,** '17-'22), which is also Lebanon's Electric Aggregation Committee pursuant to RSA 53-E. In additional to usual Councilor duties, authorized to represent the City as advocate and expert witness in several PUC proceedings, including Grid Modernization, development of new Net Metering tariffs, Liberty's residential battery pilot where I helped design innovative Time-of-Use rates approved by the PUC, development of a state-wide multi-use energy data platform, and distribution rate cases for Liberty, where I secured the right of municipalities to install their own LED street lights with controls that allow dimming and credit for such reduced energy use. Principal author, on behalf the City or CPCNH, of all or part of several energy related bills that became NH law in 2019-'23, including extensive updates to RSA 53-E, that enables community power aggregations (CPAs) for electricity supply. Facilitated and led the drafting of proposed administrative rules for CPAs.
- **Community Power Coalition of New Hampshire, Chair** (4/22-persent), **Vice Chair** (10/1/21-4/22) & coalition organizing group (2020-9/21), a start-up NH nonprofit operating as an instrumentality of 50 municipalities and counties per a joint powers agreement under RSA 53-A to provide power supply and related energy services to member community power aggregations.
- **Governance Council** to develop **Statewide, Multi-Use Online Energy Data Platform**, arising from PUC approved settlement in DE 19-197, representing community power aggregations in collaboration with investor-owned utilities, CENH, and other stakeholders.

PAST STATE, REGIONAL & NATIONAL REGULATORY, LEGISLATIVE & PUBLIC POLICY EXPERIENCE

- **New Hampshire Public Utilities Commission, Commissioner,** 12/27/2005 – 2/6/2012:

The NHPUC is vested with general jurisdiction over regulated electric, natural gas, water, and sewer utilities (and telecommunications until 2011), for issues such as rates, quality of service, finance, accounting, and safety. The NHPUC's core mission is to ensure that customers of regulated utilities receive safe, adequate and reliable service at just and reasonable rates. The NHPUC also advocated on behalf of the state in certain regional and national forums (such as ISO-NE stakeholder processes and FERC) and administered the state's Renewable Energy and Greenhouse Gas Emissions Reduction

Funds. Participated in approximately 360 adjudicatory and rulemaking proceedings with public hearings and over 1,000 published adjudicatory orders and decisions. Approved, with two other Commissioners, agency proposed budget, policies and procedures, and hiring/selection of general counsel, staff attorneys, and division directors. Often served as agency point person in legislative hearings and proposed administrative rules.

  - **National Association of Regulatory Utility Commissioners** (NARUC) Energy Resources & Environment Committee; 2006-2011; **Co-Vice-Chair**, 2009-2011.
  - FERC-NARUC Smart Grid/Demand Response Collaborative, 2008-2011.
  - **New England Conference of Public Utility Commissioners** (NECPUC), Vice President, 9/09-9/10; P**resident,** 9/10-9/11.
  - Electric Power Research Institute (EPRI), Advisory Council to the Board of Directors, 2009-2011; Energy Efficiency/Smart Grid Public Advisory Group, 2008-2010.
  - Regional Evaluation, Measurement & Verification (EM&V) Forum, Steering Committee, Northeast Energy Efficiency Partnership, 2007-2011; **Co-Chair,** 2011.
  - RGGI (Regional Greenhouse Gas Initiative) one of two NH agency head representatives and **RGGI, Inc.; Secretary** (2007-2009); **Vice-Chair** (2009-2011). Participated as a corporate officer and thus as a member of the Executive Committee of the Board of Directors from inception to 10/11 when I stepped down. RGGI Inc. is the regional organization supporting implementation of RGGI. Participated in selection of the first Executive Director and in the review, revision, and adoption of all corporate governance polices, annual budgets, and governance matters.
  - NH Energy & Climate Collaborative, 2009-2011.
  - Governor's Climate Change Policy Task Force, NH's Climate Action Plan, 2008.
  - Northeast International Committee on Energy (NICE) and Climate Change Steering Committee of the Conference of New England Governors and Eastern Canadian Premiers, 2007-2008.
  - NH Site Evaluation Committee, 2006-2011 and Energy Planning Advisory Board, 2006.
  - ISO-New England Scenario Analysis Steering Committee Co-Chair (for NECPUC, 2007).
  - Collective Bargaining Team for State of New Hampshire (as employer), 2007.
  - Speaker and panel moderator at various meetings or conferences of NECPUC, NARUC, ISO-NE, NEEP, ACEEE, NEPPA, NECA, NESEA Building Energy, ACI New England, Restructuring Roundtable, and other forums.

- Commission to Study Child Support and Related Child Custody Issues, 2003-2006; 2003-2004 as a State Senator; 2005-2006 as Governor's designee, Vice-Chair.

- **NH State Senator,** District 5, 1998-2004:
  - **Senate Finance Committee**, 1998-2004, over the course of 3 state budget cycles worked on detailed review and recommendations for each of the 3 divisions of the state's approximately $4 billion annual budget.
  - **Senate Energy & Economic Development Committee**, 1998-2004; **Chair**, 2000-2002; **Vice Chair,** 2002-2004.
  - **Senate Ways & Means Committee**, 1998-2000, **Chair**.
  - Senate Environment Committee, 1998-2004.
  - Senate Transportation Committee, 1998-2000, 2003-2004.
  - **Joint Legislative Committee on Administrative Rules**, 2001-2004; **Chair**, 2001-2002; **Vice Chair** 2002-2004.
  - Fiscal Committee of the General Court, 1999-2000.
  - **Electric Utility Restructuring Oversight Committee**, 1998-2004; **Co-Chair**, 1998-2000.

  - Telecommunications Planning and Development Advisory Committee, 2001-2004.
  - **Nuclear Decommissioning Finance Committee,** 2003-2004.
  - Dam Management Review Committee, 1999-2004.
  - Oil Fund Disbursement Board, 1999-2000.
  - NH Business Finance Authority Board, 1999-2002.
  - Assessing Standard Board, 2002-2004.
  - **Equalization Standards Board,** 2001-2004, **Chair and Vice Chair.**
  - Land Use Management & Farmland Preservation Study Committee, 1998-1999.
  - Mercury Source Reduction and Recycling Issues Study Committee, 1999.
  - Sullivan County Regional Refuse District Issues Study Committee, 1999.
  - Requirements for use of Methyl T-Butyl Ether & Gasoline Components Study Committee, 1999-2000.
  - **State Wireless Communications Policy Study Committee,** 2000, **Chair.**
  - Salary Structure for Unclassified State Officers Study Committee, 2000.
  - Renewable Energy Sources Promotion Methods Study Committee, 2000.
  - 211 Commission, 2002.
  - Exemption from Property Taxes for Not-For-Profit Hospitals Study Committee, 2003.
  - Methods of Supporting Continued Operation of Wood-Fired Electrical Generating Facilities Study Committee, 2002.
  - Eminent Domain Proceedings Study Committee, 2003.
  - Pricing of Milk Products Study Committee, 2003.
  - Options for Reducing the Impact of Exhaust Emissions from Diesel Engines Study Committee, 2004.
  - Commission on Setback Requirements for Land Application of Septage, Biosolids and Short Paper Fibers, 2004.
  - Commission on Encouraging Municipal Recycling and Tax Exemptions for Water and Air Pollution Control Facilities under RSA 72:12-a, 2004.
  - Committee to Study the Effects that Utility Restructuring has had on the State's Hydro-Lease Program and the State Dam Maintenance Fund and to Study Alternatives for Funding the Operation and Maintenance of State-Owned Dams, 2003-2004.
  - Establishment of a Farm Viability Program Study Committee, 2004.
  - Speaker on Genetic Testing Issues and Public Policy, Dartmouth Community Medical School, spring, 2000. Prime sponsor & author of NH genetic testing info protection law, RSA 141-H.
  - Speaker on NH's restructuring experience at New England "Mid-Course Review of Electric Restructuring," sponsored by National Council on Electricity Policy and NCSL, 2000.
  - Speaker at the Lebanon, Hanover, Claremont, New London, and Nashua Rotary Clubs, Concord Chamber of Commerce, BIA committees, and other forums; various topics; various dates.
  - Commencement Speaker: Lebanon College, 1999; NH Community Technical College at Claremont, 2004.
  - Speaker at NH Bar CLE course on the Administrative Rules process, November 2004.

- **NH State Representative,** 1992-1998:
  - **Science, Technology & Energy Committee,** 1992-1998; dealt with utility, energy, telecommunications, and air quality policy; **Chair** of Electric Utilities Subcommittee.
  - Small Power Producers and PSNH Renegotiations Legislative Oversight Committee, 1994.
  - Retail Wheeling and Restructuring Study Committee, 1995, **Chair** of Policy Principles, Social and Environmental Issues Subcommittee whose report became the foundation for NH's Electric Utility Restructuring statute, RSA 374-F.

- **Electric Utility Restructuring Oversight Committee,** 1996-1998.
- Member of state's negotiating team with Public Service Company of NH and prime sponsor of securitization (debt refinancing) legislation that ended litigation, and resulted in one of the largest, if not the largest, voluntary write-off of equity by a US electric utility, large reductions in interest costs, and a reduction of average NH electric rates from the highest in the nation to the regional average. Sponsor of over a dozen bills dealing with energy policy and electric utilities, most of which became law, including prime sponsorship of NH's first solar/renewable net energy metering law and an update of the energy facility siting statute.
- **Testified on State-Federal issues related to electric utility restructuring before the Energy & Power Subcommittee of the U.S. House Committee on Commerce,** February, 1996.
- Testified before the Maine legislature on New Hampshire's restructuring efforts.
- Speaker on "Tax Aspects of Restructuring NH's Electric Utility Industry" NCSL seminar, 1998.

- **Legislative Regional and National Work:**
  - **Council of State Governments, Eastern Regional Council (CSG/ERC):**
    - **Energy and Environment Committee,** member, 1997-2004; **Vice-Chair,** 2001-2003.
    - Executive Committee, member, 1999-2002.
    - Northeast Electric Restructuring Task Force, 1998-2000.
  - **National Conference of State Legislatures (NCSL):**
    - **Advisory Council on Energy,** 1997-2004; **Chair,** 2001-2004. As Chair facilitated structured discussions between federal and state energy and utility officials, private sector experts, various stakeholders, state legislators, and NCSL staff to anticipate new trends in energy issues and to assist state legislatures in responding to those trends. Reviewed and commented on drafts of various publications.
    - **Energy and Transportation Committee, Assembly on Federal Issues, (and successor Energy & Electric Utilities Committee),** 1998-2004; **Chair,** 2000-2001. As Chair facilitated a consensus based comprehensive update of NCSL's National Energy Policy (and other policies) used for lobbying the federal government on behalf of all state legislatures.
    - Partnership on Electric Industry Taxation, 2002-2004.
    - Environment Committee, 1999-2002.
    - **Testified before the United States Senate Committee on Energy and Natural Resources on "Electric Industry Restructuring," with a particular focus on transmission issues, on behalf of NCSL,** April, 2000.
    - Speaker on "Electric Power: to the States or the Federal Government," (state/federal jurisdictional issues) at NCSL Annual Meeting, 1996.
    - Speaker on "Stranded Costs: Who Pays for Electric Industry Restructuring?" at NCSL Annual Meeting, 1998.
    - Speaker on Regional & State Policy Option & NH's 4-pollutant legislation at NCSL Energy Institute on Energy and Air Quality Issues, June, 2002.
    - Moderator, panel on State Policy & Greenhouse Gases, NCSL Annual Meeting, 2003.
  - **National Council on Electricity Policy, Steering Committee,** member, 2001-2004. The National Council was a joint venture of NCSL, the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Energy Officials, and the National Governor's Association (NGA) to assist policymakers with the challenges posed by the dramatic changes brought about by the reexamination of the traditional franchise electric system with funding from the U.S. Department of Energy. (Formerly the National Council on Competition and the Electric Industry.)
  - Speaker on "Regional State Committees – How do they fit into the bigger picture? – Effective

Regulatory Policies for Supporting New England's Markets," at Emerging Issues in New England conference, sponsored by Edison Electric Institute and ISO-New England (among others), Nashua, NH, November, 2003.

- Speaker on "The Legislative Process: How can it support renewable energy?" at Building Energy 04 and 05 conferences, sponsored by the Northeast Sustainable Energy Association Boston, MA, March 2004 and 2005.

OTHER WORK EXPERIENCE

- **Home Improvement Design & Build,** 2012-present, as time allows, progress on completing 35 years of work on home energy efficiency and asset preservation improvements such as structural repairs and improvements to roof and front porches. Removed 4 layers of old shingles and re-sheathed the entire roof in preparation for new standing seam metal roof. Upgraded electrical system and added new 7.7 kW (AC) PV system. Replaced old oil heating system with new automatic wood pellet boiler, built new radiant heat zones and custom pellet store after air sealing and maximizing insulation throughout so heating load is only 1.3 tons pellets/year for 2,000 s.f.
- Managing General Partner, TCG Development Group, 1986-1994. Developed and operated the Courtyard Pavillion, retail building at 45 Hanover St. in downtown Lebanon.
- Various jobs from 1976 –1985 including waiting on tables, job training assessment specialist, and a partner in Retrofit Associates, an energy conservation/renewable energy consulting and contracting business.

EDUCATION

- Mt. Ararat School (public high school), Topsham, Maine, 1974, 2nd in class.
- **Dartmouth College, class of 1978**, **B.A.** with Distinction in major of Geography and Environmental Studies, **1980,** with course work including New England Energy Futures, Environmental Systems, Environmental Policy Formulation, and engineering courses in Community Systems (e.g. electric and water utilities) and Principles of Systems Design. Authored 60 page independent research paper (Xerox grant) on "Ownership and Control in the U.S. Electric Utility Industry: Policy Implications."
- **M.S. in Community Economic Development, Southern NH University, 1985,** with course work in such areas as accounting, financial and organizational management, financing, and housing and business development.

COMMUNITY SERVICE

- **City of Lebanon**, in addition to current work:
  - Pedestrian and Bicyclist Advisory Committee, 1995-present; **Chair**, 1995-1998.
  - Lebanon Economic Vitality Exchange, City Council representative, 2016-2020
  - Class VI Roads Advisory Committee, 2005-2007.
  - Planning Board member, 1995-1998.
  - Building Codes Review Committee, 1993-1994.
  - Downtown Parking Committee, 1993-1994.
  - Downtown Improvement Committee, 1990-1991.
  - Downtown Revitalization Study Committee, 1983-1984.
  - Energy Commission, 1980-1982.
- Lebanon Garden Club, Treasurer, 1986- present.
- Vital Communities, Board of Directors, 5/12 – 6/18; **Vice Chair**'17-18, Advisory Council, '02-'12.
- Sustainable Energy Resource Group, Board of Directors, 2013 – 2015.

- Lebanon Opera House Improvement Corporation, founding incorporator and Board of Directors, 1991-1998.
- Friends of the Northern Rail Trail in Grafton County, founding incorporator and Board of Directors, 1996-1998.
- Headrest, 24 hotline volunteer and Alcohol Crisis Team, EMT, 1981-1983.
- LISTEN, Board of Directors (**Vice President**, Clerk, Chair of numerous committees), 1978-1984.

TESTIMONY & PUBLICATIONS

C. Below, "Lebanon Community Power's Transactive Energy Municipal Aggregation Pilot", Presentation to the 2018 Transactive Energy Conference, 6/14/18, MIT, Cambridge, MA, available here: https://lebanonnh.gov/DocumentCenter/View/6981/TESC-18-Presentation-Clifton-BELOW---LCP?bidId=

C. Below, "Direct Testimony of Clifton C. Below," NHPUC Docket No. DE 16-576, Electric Distribution Utilities Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators, 10/24/17. This concerns conceptualization of RTP pilot and is available at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/TESTIMONY/16-576_2016-10-24_LEBANON_DTESTIMONY_C_BELOW.PDF, with "Rebuttal Testimony of Clifton C. Below" available at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/TESTIMONY/16-576_2016-12-22_COL_RTESTIMONY_C_BELOW.PDF .

C. Below, "Testimony of Clifton C. Below," NHPUC Docket # DE 19-064, Liberty Utilities Request for Change in Rates, 12/6/19. This testimony concerns enabling municipalities to own their own smart streetlights with communicating adaptive controls, including built-in revenue grade meters. A settlement agreement approved by the Commission enabled the City's Smart Street Lighting LED conversion project, the first in the state to allow kWh credit for dimming of streetlights. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-064/TESTIMONY/19-064_2019-12-09_COL_TESTIMONY_BELOW.PDF.

C. Below, "Testimony of Clifton C. Below," New Hampshire Public Utilities Commission (NHPUC), Docket No. 19-197, Electric and Natural Gas Utilities, Development of a Statewide, Multi-use Online Energy Data Platform, 8/17/20, found at https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TESTIMONY/19-197_2020-08-18_LEBANON_LGC_REV_TESTIMONY_BELOW.PDF

S. O. Muhanji, C. Below, T. Montgomery and A. M. Farid, "Enabling a Shared Integrated Grid via New England Energy Water Nexus," 2019 IEEE International Symposium on Technology and Society (ISTAS), Medford, MA, USA, 2019, pp. 1-6, doi: 10.1109/ISTAS48451.2019.8938013. (https://ieeexplore.ieee.org/document/8938013)

S. O. Muhanji, S. Golding, T, Montgomery, C, Below and A. M. Farid, "A Distributed Economic Model Predictive Control Design for a Transactive Energy Market Platform in Lebanon, NH," 2020, arXiv:2012.04058 [eess.SY]. (https://arxiv.org/abs/2012.04058)

S. O. Muhanji, S. Golding, T. Montgomery, C. Below and A. M. Farid, "Developing a Blockchain Transactive Energy Control Platform in Lebanon to Transform the New Hampshire Electricity Market," *2020 IEEE PES Transactive Energy Systems Conference (TESC)*, 2020, pp. 1-5, doi: 10.1109/TESC50295.2020.9656933 (https://ieeexplore.ieee.org/document/9656933).

Tebbetts, H., Huber, L., Below, C., "Technical Statement Regarding Time-of-Use (TOU) Model", NHPUC, Docket No. 17-189, Liberty Utilities Petition to Approve Battery Storage Pilot Program, available at: https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2018-11-19_GSEC_TECH_STATEMENT_TOU.PDF
This TOU rate model, developed in large part by C. Below, was approved for Liberty's Battery pilot and for a residential EV charging tariff. It has been described by the Regulatory Assistance Project as "the most advanced modern rate design in New England."

Yellow highlighting indicates matter called out in statute to be considered by PUC as part of net metering proceedings, such as DE 22-060. Enlarged, **Bold** and **blue text** call out particularly relevant matters to DE 22-060. ***Bold italics*** may indicate recently added language.

TITLE XXXIV
PUBLIC UTILITIES

CHAPTER 362-A
LIMITED ELECTRICAL ENERGY PRODUCERS ACT

Section 362-A:1

362-A:1 Declaration of Purpose. – It is found to be in the public interest to provide for small scale and diversified sources of supplemental electrical power to lessen the state's dependence upon other sources which may, from time to time, be uncertain. It is also found to be in the public interest to encourage and support diversified electrical production that uses indigenous and renewable fuels and has beneficial impacts on the environment and public health. It is also found that these goals should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3. It is further found that net energy metering for eligible customer-generators may be one way to provide a reasonable opportunity for small customers to choose interconnected self generation, encourage private investment in renewable energy resources, stimulate in-state commercialization of innovative and beneficial new technology, enhance the future diversification of the state's energy resource mix, and reduce interconnection and administrative costs.

Source. 1978, 32:1. 1994, 362:2. 1998, 261:1, eff. Aug. 25, 1998. 2010, 143:1, eff. Aug. 13, 2010.

[*This sentence added in 1998 was deleted in 2010:* [~~However, due to uncertain cost and technical impacts to electric utilities and other ratepayers, the general court finds it appropriate to limit the availability of net energy metering to eligible customer-generators who are early adopters of small-scale renewable electric generating technologies.~~]

[Chapter 33 NH laws of 2016 has this significant purpose statement:

31:1 Purpose Statement. **To meet the objectives of electric industry restructuring pursuant to RSA 374-F, including the overall goal of developing competitive markets and customer choice to reduce costs for all customers**, and the purposes of RSA 362-A and RSA 362-F to promote energy independence and local renewable energy resources, **the general court finds that it is in the public interest to continue to provide reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair compensation for such locally produced power while ensuring costs and benefits are fairly and transparently allocated among all customers.** The general court continues to promote

Commented [CB1]: This language was added in 1998 by the same bill that created net metering in the first place, sponsored by then Reps. Below and Bradley. The bill also enacted major reforms to the rest of the LEEPA statute and was the result of building consensus over 11 work sessions in the immediate wake of enacting electric utility restructuring to move generation into competitive markets with customer choice.

Commented [CB2]: This is the law that expanded group net metering provisions in the statute, among other things, and has been the one complete repeal and replacement of the entire text of Section 362-A:9, though much carried over.

a balanced energy policy that supports economic growth and promotes 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.

[Chapter 266 NH laws of 2017 has this significant purpose statement:

226:1 Purpose. The general court finds it is in the public interest to promote customer choice and energy independence by eliminating market barriers to solar energy that low-to-moderate income residential customers face, by sustaining and promoting local renewable energy resources and New Hampshire jobs in the solar and wood products industries, by promoting the stabilization and lowering of future energy costs with more clean energy supply and greater energy diversification, and by further reducing energy costs by reducing New Hampshire's peak demand, including our share of regional electric transmission costs, which recently went up due to our increased share of the regional peak demand.

2022; 328:2 *(SB 262) made these findings immediately before new paragraph XXII*:

328:2 Findings; Distributed Energy Resources. Customer-owned distributed energy resources (DERs) that connect to the distribution grid can provide a beneficial hedge against volatile electricity prices and stimulate investment and employment in the state economy. Because DERs frequently utilize clean, renewable energy sources, they can reduce air pollution and greenhouse gas emissions to benefit public health and environmental quality. For these reasons, the general court finds it is in the public interest to stimulate the deployment of DERs in New Hampshire and eliminate unreasonable barriers thereto.

Section 362-A:1-a

362-A:1-a Definitions. –

In this chapter:
I. " Bio-oil " means a liquid renewable fuel derived from vegetable oils, animal fats, wood, straw, forestry byproducts, or agricultural byproducts using noncombustion thermal, chemical, or biological processes, including, but not limited to, distillation, gasification, hydrolysis, or pyrolysis, but not including anaerobic digestion, composting, or incineration.
I-a. " Bio synthetic gas " means a gaseous renewable fuel derived from vegetable oils, animal fats, wood, straw, forestry byproducts, or agricultural byproducts using noncombustion thermal, chemical, or biological processes, including, but not limited to, distillation, gasification, hydrolysis, or pyrolysis, but not including anaerobic digestion, composting, or incineration.
I-b. " Biodiesel " means a renewable diesel fuel substitute that is composed of mono-alkyl esters of long chain fatty acids, is derived from vegetable oils or animal fats, and meets the requirements of the American Society for Testing and Materials (ASTM) specification D6751.
I-c. " Cogeneration facility " means a facility which produces electric energy and other forms of useful energy, such as steam or heat, which are used for industrial, commercial, heating, or cooling purposes.
I-d. " Combined heat and power system " means a new system installed after July 1, 2011, that

produces heat and electricity from one fuel input using an eligible fuel, without restriction to generating technology, has an electric generating capacity rating of at least one kilowatt and not more than 30 kilowatts and a fuel system efficiency of not less than 80 percent in the production of heat and electricity, or has an electric generating capacity greater than 30 kilowatts and not more than one megawatt and a fuel system efficiency of not less than 65 percent in the production of heat and electricity. Fuel system efficiency shall be measured as usable thermal and electrical output in BTUs divided by fuel input in BTUs.
II. "Commission" means the New Hampshire public utilities commission.
II-a. "Electricity suppliers" has the same meaning as in RSA 374-F:2, II.
II-b. " Eligible customer-generator " or " customer-generator " means an electric utility customer who owns, operates, or purchases power from an electrical generating facility either powered by renewable energy or which employs a heat led combined heat and power system, with a total peak generating capacity of up to and including one megawatt, except as provided for a municipal host as defined in paragraph II-c, that is located behind a retail meter on the customer's premises, is interconnected and operates in parallel with the electric grid, and is used to offset the customer's own electricity requirements. Incremental generation added to an existing generation facility, that does not itself qualify for net metering, shall qualify if such incremental generation meets the qualifications of this paragraph and is metered separately from the nonqualifying facility.
II-c. " Municipal host" means a customer generator with a total peak generating capacity of greater than one megawatt and less than 5 megawatts used to offset the electricity requirements of a group consisting exclusively of one or more customers who are political subdivisions, provided that all customers are located within the same utility franchise service territory. ~~A municipal host shall be located in the same municipality as all group members if the facility began operation after January 1, 2021.~~ A municipal host may be owned by either a public or private entity. For this definition, " political subdivision " means the state of New Hampshire or any city, town, county, school district, chartered public school, village district, school administrative unit, or any district or entity created for a special purpose administered or funded by any of the above-named governmental units.

Commented [CB3]: This sentence will be deleted by Chapter 233:2, NH Laws of 2023 (HB 281), effective 10/07/23

II-d. " Eligible fuel " means natural gas, propane, wood pellets, hydrogen, or heating oil when combusted with a burner, including air emission standards for the device using the approved fuel.
II-e. " Heat led " means that the combined heat and power system is operated in a manner to satisfy the heat usage needs of the customer-generator.
II-f. " Department " means the New Hampshire department of energy.
III. " Limited producer " or " limited electrical energy producer " means a qualifying small power producer, a qualifying storage system, or a qualifying cogenerator, with a maximum rated generating or discharge capacity of less than 5 megawatts that:
(a) Does not participate in net energy metering. Non-participation in net energy metering may be achieved by canceling participation in such upon assuming limited production.
(b) Is not registered as a generator, asset, or network resource with ISO New England.
(c) Does not otherwise participate in any FERC jurisdictional wholesale electricity markets, except as an alternative technology regulation resource (ATRR) to the extent ATRRs are deemed by ISO New England to function as retail or network load reducers for all other ISO New England purposes. Such non-participation in FERC jurisdictional interstate wholesale markets may be achieved by retirement from such markets.

III-a. "Net energy metering" means measuring the difference between the electricity supplied over the electric distribution system and the electricity generated by an eligible customer-generator which is fed back into the electric distribution system over a billing period.
IV. "Person" means any individual, partnership, association, corporation, governmental unit or agency or any combination thereof.
V. "Primary energy source" means the fuel or fuels used for the generation of electric energy, except that such term does not include the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, or control uses or the minimum amounts of fuel required to alleviate or prevent unanticipated equipment outages or emergencies directly affecting the public health, safety or welfare which would result from electric power outages.
VI. "Qualifying cogeneration facility" means a cogeneration facility which the commission determines meets such requirements, including requirements respecting minimum size, fuel use and fuel efficiency, as the commission may prescribe and which is owned by a person not primarily engaged in the generation or sale of electric power, other than electric power solely from cogeneration facilities or small power production facilities.
VII. "Qualifying cogenerator" means the owner or operator of a qualifying cogeneration facility.
VII-a. "Qualifying facility" means either or both of a qualifying small power production facility or qualifying cogeneration facility.
VIII. "Qualifying small power producer" means the owner or operator of a qualifying small power production facility.
IX. "Qualifying small power production facility" means a small power production facility which the commission determines meets such requirements, including requirements respecting fuel use, fuel efficiency and reliability, as the commission may prescribe and which is owned by a person not primarily engaged in the generation or sale of electric power, other than electric power solely from cogeneration facilities or small power production facilities.
IX-a. " Qualifying storage system " means an electric energy storage system as defined in RSA 72:84 ***or a grid-integrated electric vehicle as defined in RSA 374-F:2***.
X. " Small power production facility " means a facility which produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, bio-oil, bio synthetic gas, biodiesel, or any combination thereof and which has a power production capacity which, together with any other facility located at the same site, as determined by the commission, is not greater than 30 megawatts.

Commented [CB4]: Added effective 10/7/23 by Chapter 243, NH Laws of 2023 (SB 166), relative to grid modernization.

Source. 1983, 395:1. 1989, 211:1. 1998, 261:2-4. 2006, 294:1, 2. 2007, 174:1, eff. Aug. 17, 2007. 2010, 143:2, eff. Aug. 13, 2010. 2011, 168:1, 2, eff. July 1, 2011. 2013, 266:1, eff. July 24, 2013. 2014, 130:2, eff. Aug. 15, 2014. 2021, 91:232, eff. July 1, 2021; 229:11, eff. Aug. 26, 2021. 2022, 218:1, 2, eff. June 17, 2022. 2022, 245:33, eff. Aug. 20, 2022, 2023, 233:2, eff. Oct. 7, 2023; 243:4, eff. Oct. 7, 2023.

RELEVANT REFERENCED DEFINITIONS:

72:84 Electric Energy Storage System; Definition. – In this subdivision " electric energy storage system " means a facility located behind a retail meter that stores electrical energy that is otherwise produced by an electricity generator or uses electricity to concentrate and store thermal energy, by electrical, chemical, mechanical, or thermal means, for discharge or use at a later time, whether in the form of thermal energy to meet space or process heating or cooling loads or electricity, which can be used to reduce peak loads, compensate for variability in renewable energy production, or provide other grid services, and which does not participate in any wholesale energy markets administered by ISO New England as a registered asset or otherwise. An electric energy storage system shall not include conventional electric resistance or gas domestic hot water heaters.

Source. 2019, 327:4, eff. Oct. 15, 2019.

RSA 374-F:2 . . .

X. ***"Grid-integrated electric vehicle" or "GIEV" means a battery-run motor vehicle that has the ability for 2-way power flow between the vehicle and the electric grid and the communications hardware and software that allow for the external control of battery charging and discharging by the electric utility customer, an electric distribution company, an electricity supplier, or an aggregator.***

Source. 2023, 243:3, eff. Oct. 07, 2023.

Section 362-A:9

362-A:9 Net Energy Metering.

I. Standard tariffs providing for net energy metering shall be made available to eligible customer-generators by each electric distribution utility in conformance with net metering rules adopted and orders issued by the commission. Each net energy metering tariff shall be identical, with respect to rates, rate structure, and charges, to the tariff under which a customer-generator would otherwise take default generation supply service from the distribution utility. Such tariffs shall be available on a first-come, first-served basis within each electric utility service area under the jurisdiction of the commission until such time as the total rated generating capacity owned or operated by eligible customer-generators totals a number equal to 100 megawatts, with 50 megawatts of the 100 megawatts allocated to the 4 electric distribution utilities that were subject to the commission's jurisdiction in 2010 multiplied by each such utility's percentage share of the total 2010 annual coincident peak energy demand distributed by those 4 utilities, and 50 megawatts of the 100 megawatts allocated to the state's 3 investor-owned electric distribution utilities, multiplied by each such utility's percentage share of the total 2010 annual coincident peak energy demand distributed by those 3 utilities, all to be determined by the commission and to be utilized by eligible customer-generators located within each such utilities' service territory. Eighty percent of each utility's share of the 50 megawatts shall be apportioned to facilities with a total generating capacity of not more than 100 kilowatts and 20 percent to facilities with a total generating capacity in excess of 100 kilowatts, but no greater than one megawatt. The 50 megawatts of capacity shall be made available to eligible customer-generators until such time as commission approved alternative net metering tariffs approved by the commission become available. No more than 4 megawatts of such total rated generating capacity shall be from a combined heat and power system as defined in RSA 362-A:1-a, I-d.

II. Competitive electricity suppliers registered under RSA 374-F:7 and municipal or county aggregators under RSA 53-E **may determine the terms, conditions, and prices under which they agree to provide generation supply to and** credit, as an offset to supply, or **purchase the**

Commented [CB5]: This new definition becomes effective 10/7/23 by Chapter 243, NH Laws of 2023 (SB 166), relative to grid modernization.

Commented [CB6]: This terms, conditions, and limits of this paragraph I, along with **paragraphs III, IV, V, and VI**, are all subject to modification by the PUC for alternative metering tariffs going forward pursuant to paragraph XVI below (2016, 31:5).

Commented [CB7]: This language is now moot. It was added in 2016 to deal with the fact that one of the utilities had reached it's cap and had to close its net metering queue It was a stop gap measure until the PUC could act under authority and direction given to the PUC in the same legislation to eliminate the cap, which they did, in DE 16-576, Order No. 26,029 approving new alternative net metering tariffs.

Commented [CB8]: The text in bold purple was added in 2010, Chapter 143, which repealed and replaced the whole net metering section, though it was a rephrasing of language that was part of the original enactment of NEM in 1998 in paragraph III as cited below in the next comment. All of the rest of this text was added by 2020, 21:1.

generation output exported to the distribution grid from eligible customer-generators. The commission may require appropriate disclosure of such terms, conditions, and prices or credits. Such output shall be accounted for as a reduction to the customer-generators' electricity applicable line loss adjustments, as approved by the commission. Nothing in this paragraph shall be construed as limiting or otherwise interfering with the provisions or authority for municipal or county aggregators under RSA 53-E, including, but not limited to, the terms and conditions for

~~**III. . . . Electricity suppliers may voluntarily determine the terms, conditions, and prices under which they will agree to provide generation supply to and purchase net generation output from eligible customer-generators . . . .**~~

Commented [CB9]: This text was part of the original enactment of net metering, 1998, 261:10 (HB 485), and was repealed in 2010 and replaced with the new bold purple language shown above in paragraph II.

III. Metering shall be done in accordance with normal metering practices. A single net meter that shows the customer's net energy usage by measuring both the inflow and outflow of electricity internally shall be the extent of metering that is required at facilities with a total peak generating capacity of not more than 100 kilowatts. A bi-directional metering system that records the total amount of electricity that flows in each direction from the customer premises, either instantaneously or over intervals of an hour or less, shall be required at facilities with a total peak generating capacity of more than 100 kilowatts. Customer-generators shall not be required to pay for the installation of net meters, but shall pay for the installation of all bi-directional metering systems as outlined in utility interconnection tariffs or rules.

IV. (a) For facilities with a total peak generating capacity of not more than 100 kilowatts, when billing a customer-generator under a net energy metering tariff that is not time-based, the utility shall apply the customer's net energy usage when calculating all charges that are based on kilowatt hour usage. Customer net energy usage shall equal the kilowatt hours supplied to the customer over the electric distribution system minus the kilowatt hours generated by the customer-generator and fed into the electric distribution system over a billing period.
(b) For facilities with a total peak generating capacity of more than 100 kilowatts, the customer-generator shall pay all applicable charges on all kilowatt hours supplied to the customer over the electric distribution system, less a credit on default service charges equal to the metered energy generated by the customer-generator and fed into the electric distribution system over a billing period.

V. When a customer-generator's net energy usage is negative (more electricity is fed into the distribution system than is received) over a billing period, such surplus shall either:
(a) Be credited to the customer-generator's account on an equivalent basis for use in subsequent billing cycles as a credit against the customer's net energy usage or bill in a manner consistent with either subparagraph IV(a) or IV(b), as applicable; or

(b) Except as provided in paragraph VI, the customer-generator may elect to be paid or credited by the electric distribution utility for its excess generation at rates that are equal to the utility's avoided costs for energy and capacity to provide default service as determined by the commission consistent with the requirements of the Public Utilities Regulatory Policy Act of 1978 (PURPA). The commission shall determine reasonable conditions for such an election, including the frequency of payment, provided that the commission requires the option of payment at least quarterly, and how often a customer-generator may choose this option versus the option in subparagraph (a).

V-a. A customer-generator subject to the alternative net metering tariff adopted by the commission in order 26,029 issued on June 23, 2017, and subsequent orders issued thereafter in docket DE 16-576, may elect to receive a payment from the distribution utility either on an annual basis in an amount equal to the accrued monetary bill credit balance that exceeds $100 as of the end of the March billing period, or on a quarterly basis in an amount equal to the amount of the accrued monetary bill credit balance that exceeds $25 as of the end of the most recent billing period preceding such quarterly payment. The costs reasonably incurred by a utility pursuant to this paragraph shall be recoverable.

VI. Instead of the option in subparagraph V(b), an electric distribution utility providing default service to customer-generators may voluntarily elect, annually, on a generic basis, by notification to the commission, to purchase or credit such excess generation from customer-generators at a rate that is equal to the generation supply component of the applicable default service rate, provided that payment is issued at least as often as whenever the value of such credit, in excess of amounts owed by the customer-generator, is greater than $50.

VII. A distribution utility may perform an annual calculation to determine the net effect this section had on its default service and distribution revenues and expenses in the prior calendar year. **The method of performing the calculation and applying the results, as well as a reconciliation mechanism to collect or credit any such net effects with appropriate carrying charges and credits applied, shall be determined by the commission.**

VIII. Notwithstanding other provisions of this section, the commission may establish, on a utility-specific or generic basis, a methodology by which customer-generators may be provided service under time-based, net energy metering tariffs. The methodology shall specify how a customer's energy usage and generation shall be metered, how net energy usage shall be calculated and any applicable charges applied, and how excess generation shall be credited, consistent with size limits and the terms and conditions and intent of this section and other requirements of state and federal law.

IX. Renewable energy credits shall remain the property of the customer-generator until such credits are sold or transferred. If an electric distribution utility acquires renewable energy credits from a customer-generator in conjunction with purchasing excess generation, it may apply such generation and credits to its renewable energy source default service option under RSA 374-F:3, V(f).

X. The department shall adopt rules, pursuant to RSA 541-A, to:
(a) Establish reasonable interconnection requirements for safety, reliability, and power quality as it determines the public interest requires. Such rules shall not exceed applicable test standards of the American National Standards Institute (ANSI) or Underwriters Laboratory (UL); and
(b) Implement the provisions of this section.

XI. The department may by order, after notice and hearing:
(a) Waive any of the limitations set forth in this chapter for targeted net energy metering arrangements that are part of a utility strategy to minimize distribution or other costs; and
(b) Implement any utility-specific provisions authorized under this section.

XII. Once the department has established standards for equipment used by eligible customer-generators, electric distribution utilities shall not require any additional standards or testing for transmission equipment as a condition of net energy metering.

XIII. Customer-generators shall be responsible for all costs associated with interconnection with the distribution system.

Commented [CB10]: This new paragraph, along with amendments to the previous subparagraph, were made by [2022 Chapter 152 (SB 261).]

Commented [CB11]: This was added by [2010 143:3].

Commented [CB12]: This authority was transferred from PUC to DOE on 7/1/21.

Commented [CB13]: This authority was transferred from PUC to DOE on 7/1/21.

Commented [CB14]: This was originally added by [2000, 148:2].

Commented [CB15]: This was part of the original NEM law . [1998, 261:10]

XIV. (a) A customer-generator may elect to become a group host for the purpose of reducing or otherwise controlling the energy costs of a group of customers who are not customer-generators, ***except that a political subdivision, as defined in RSA 362-A:1-a, II-c, or the owner of a facility described in RSA 362-A:9, XX, that is a customer-generator, may participate as a group member.*** The group of customers shall be located within the service territory of the same electric distribution utility as the host. The host shall provide a list of the group members to the commission and the electric distribution utility and shall certify that all members of the group have executed an agreement with the host regarding the utilization of kilowatt hours produced by the eligible facility and that the total historic annual load of the group members together with the host exceeds the projected annual output of the host's facility. The department shall verify that these group requirements have been met and shall register the group host. The department shall establish the process for registering hosts, including periodic re-registration, and the process by which changes in membership are allowed and administered. Net metering tariffs under this section shall not be made available to a customer-generator group host until such host is registered by the department.

Commented [CB16]: This paragraph including original subparagraphs (a)-(e) where enacted by 2013 Chapter 266:2. Further modifications came from 2017, 226:7, 2018, 112:1, and 2019, 271:2.

Commented [CB17]: Added by 2022, 328:1 (SB 262).

Commented [CB18]: 2018; 212:3 used this phrase to replace "default service customers".

(b) Except as provided in subparagraph (c), the provisions of this section shall apply to a group host as a customer-generator.

(c) (1) Notwithstanding paragraph V, a group host shall be paid for its surplus generation at the end of each billing cycle at rates consistent with the credit the group host receives relative to its own net metering under either subparagraph IV(a) or (b) or alternative tariffs that may be applicable pursuant to paragraph XVI. Alternatively, a group host may elect to receive credits on the customer electric bill for each member and the host, with the utility being allowed the most cost-effective method of doing so according to an amount or percentage specified for each member on PUC form 909.09 (Application to Register or Re-register as a Host), along with a 3 cent per kwh addition from July 1, 2019 through July 1, 2021 and a 2.5 cent per kwh addition thereafter for low-moderate income community solar projects, as defined in RSA 362-F:2, X-a. The cent per kwh addition to the credit provided to any particular low-moderate income community solar project shall be in the amount in effect on the date that the commission issues a group host registration number for that project. The amount of the cent per kwh addition shall be grandfathered in accordance with the grandfathering provisions of the net metering tariff for customer-generators applicable to the project as in effect on the date the commission issues the project a group host registration number.

(2) On or before July 1, 2022, the department shall report on the costs and benefits of such an addition and the development of the market for low-moderate income community solar projects, and provide a recommendation on whether the addition shall be increased or decreased. The department shall report on the costs and benefits of low-moderate income community solar projects, as defined in RSA 362-F:2, X-a on or before June 1, 2020. The department shall authorize at least 2 new low-moderate income community solar projects, as defined in RSA 362-F:2, X-a, each year in each utility's service territory beginning January 1, 2020. On an annual basis, for all group host systems except for residential systems with an interconnected capacity under 15 kilowatts, the electric distribution utility shall calculate a payment adjustment if the host's surplus generation for which it was paid is greater than the group's total electricity usage during the same time period. The adjustment shall be such that the resulting compensation to the host for the amount that exceeded the group's total usage shall be at the utility's avoided cost or its default service rate in accordance with subparagraph V(b) or paragraph VI or alternative

tariffs that may be applicable pursuant to paragraph XVI. The utility shall pay or bill the host accordingly.

(d) The electric distribution utilities shall establish a list of potential low-moderate income residential customers who qualify to benefit from the low-moderate income community solar addition. This list shall consist of residents who have enrolled in or are on the waitlist for the state Electric Assistance Program.

(e) Within 90 days of the effective date of this subparagraph, the department of energy shall develop a process by which community solar developers can apply for designation as a community solar project. Such projects designate their production for the benefit of households on the list required in subparagraph (d). Such projects will qualify for the low-moderate income solar addition as established in subparagraph (c) and shall specify the amount of on-bill credit they can offer to low-moderate income homeowners. Annually, the number of projects designated as low-moderate income community solar shall not exceed a total nameplate capacity rating of 6 megawatts in the aggregate. If more than 6 megawatts of projects apply for designation, the department of energy shall select the projects that offer the largest on-bill credit.

(f) Each year, the department of energy, in consultation with the electric distribution utilities, shall select a means by which to enroll households as off-takers for these low-moderate income community solar projects. Customers shall be enrolled on an opt-out basis, notified by mail of their enrollment, and informed of the details of the project from which they are receiving credit. Once enrolled, such customers shall receive on-bill credits until such time as they no longer qualify for the Electric Assistance Program, or until they opt out from receiving credits.

(g) All reasonable and prudently-incurred costs incurred by the electric distribution utilities related to this program, including but not limited to, costs of implementation, billing, and administrative activities, shall not be borne by the utilities, but shall be recovered from customers.

(h) Utility owned projects that are designated as community solar projects shall not count against the limitation on the maximum allowed distributed energy resources as established by RSA 374-G:4.

(i) Nothing in this chapter shall preclude low-moderate income solar community projects from enrolling customers through any other method besides the process described in subparagraphs (d)-(f). A description of any alternative method used shall be filed with department of energy.

(j) The department is authorized to petition the commission to assess fines against, revoke the registration of, and prohibit from doing business in the state, any group host which violates the requirements of this paragraph and rules adopted for this paragraph pursuant to paragraph X. The commission is authorized to grant or deny such petitions.

XV. Standard tariffs that are available to eligible customer-generators under this section shall terminate on December 31, 2040 and such customer-generators shall transition to tariffs that are in effect at that time.

XVI. (a) The commission, ***through an adjudicative proceeding***, shall ***continue*** to **develop and periodically review** new alternative net metering tariffs, which may include other regulatory mechanisms and tariffs for customer-generators, and determine whether and to what extent such tariffs should be limited in their availability within each electric distribution utility's service

Commented [CB19]: Subparagraphs (d)-(e) repealed and reenacted along with (f)-(j) by 2022, 329:1.

Commented [CB20]: This grandfathering provision was added by 2016, 33 as were paragraphs XV - XVIII in their original text (since amended).

Commented [CB21]: Originally enacted as chapter 31 NH laws of 2016, though with significant amendments since then, that law triggered DE 16-576 that resulted in the first update of net metering tariffs. Significant amendments (bold italics) to the first paragraph and the additions of subparagraphs (b) & (c) were made by .

territory. In developing such alternative tariffs and any limitations in their availability, the commission shall consider: ***balancing the interests of customer-generators with those of electric utility ratepayers by maximizing any net benefits while minimizing any negative cost shifts from customer-generators to other customers and from other customers to customer-generators***; the costs and benefits of customer-generator facilities; an avoidance of unjust and unreasonable cost shifting; rate effects on all customers; alternative rate structures, including time-based tariffs pursuant to paragraph VIII; whether there should be a limitation on the amount of generating capacity eligible for such tariffs; the size of facilities eligible to receive net metering tariffs: timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; and electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms. The commission may waive or modify specific size limits and terms and conditions of service for net metering specified in paragraphs I, III, IV, V, and VI that it finds to be just and reasonable in the adoption of alternative tariffs for customer-generators. The commission may approve time and/or size limited pilots of alternative tariffs.

(b) **Until such time as the commission adopts alternative net metering tariffs that expressly apply to customer-generators with a total peak generating capacity of greater than one megawatt pursuant to the criteria set forth in this paragraph, the provisions of commission order no. 26,029 issued on June 23, 2017 and subsequent orders applicable to large customer-generators shall be applicable to customer-generators of greater than one megawatt otherwise authorized by statute**

(c) Customer-generators of greater than one megawatt total peak generating capacity that are compensated for exports to the grid pursuant to subparagraph (b) prior to commission approval of net metering tariffs that expressly apply to such customer-generators shall have the voluntary option to switch to such expressly applicable new tariff under its terms but shall not be permitted to return to a prior tariff or net metering terms once they have switched.

XVII. The commission shall issue an order initially approving or adopting such alternative tariffs, which may be subject to change or adjustment from time to time, within 10 months of the effective date of this paragraph.

XVIII. If any utility reaches any cap for net metering under paragraph I before alternative tariffs are approved or adopted pursuant to paragraph XVII, eligible customer-generators may continue to interconnect under temporary net metering tariffs under the same terms and conditions as net metering under the 100 megawatt cap, except that such customer-generators shall transition to alternative tariffs once they are approved or adopted for their utility pursuant to paragraph XVII.

XIX. No person, owner, developer, or installer of an eligible customer-generator facility, business organization, or any subsidiary thereof, shall use any unfair method of competition or any unfair or deceptive act or practice in any way for projects involving net metering.

Commented [CB22]: This subparagraph and the next were was added by 2021, Chapter 228:2 (SB 91, Part II)

Commented [CB23]: This was part of by 2016, 33 which was effective 5/2/16. The Commission temporarily adopted existing tariffs as alternative tariffs to comply with this requirement until Order 26,029 was issued on 6/23/17.

Commented [CB24]: This is the last of the 2016 additions.

Commented [CB25]: This was enacted as part of 2017, 226:7.

XX. ***Notwithstanding any provision of law to the contrary***, a hydroelectric generator with a total peak generating capacity that is at or below the capacity eligibility requirements set forth in RSA 362-A:1-a, II-b and that first became operational before July 1, 2021 and that shares equipment or facilities with other generators, energy storage facilities, or electric utility customers for interconnection to the electric grid, shall be eligible to participate in net energy metering as a customer-generator even if the aggregate capacity of the generators ***and energy storage facilities*** sharing equipment or facilities for interconnection to the electric grid exceeds the capacity eligibility requirements set forth in RSA 362-A:1-a, II-b. Such a hydroelectric generator shall be eligible to participate in net energy metering as a customer-generator based on the total peak generating capacity of each individual generating station. ***Only such a hydroelectric generator shall be eligible as a customer-generator as a matter of law without regard to whether such hydroelectric generator is the electric utility customer account of record at the point of interconnection to the electric grid, provided that such a hydroelectric generator that is not the electric utility customer account of record at the point of interconnection to the electric grid was, at one time, owned by the current electric utility customer or a prior electric utility customer at the point of interconnection to the electric grid and that such a hydroelectric generator that is not the electric utility customer account of record submits its initial proposed process and methodology described below to the department of energy and the relevant utility prior to July 1, 2024. Such a hydroelectric generator shall only participate in net metering for that portion of the hydroelectric generation in excess of the hydroelectric generator's contribution to serving the full requirements of the electric utility customer account of record at the point of interconnection to the electric grid. A hydroelectric generator eligible under this paragraph may, in reliance on revenue-grade meters, utilize a meter reading and billing determinant documentation process consistent with the rules of the public utilities commission in Puc 900 and all applicable tariffs, to determine generation eligible for net energy metering credits. The hydroelectric generator shall submit the proposed process to the department of energy and the relevant utility for approval, and provide a copy to the electric utility customer account of record at the point of interconnection to the electric grid, prior to participating in net metering. The proposed process shall include a description of the methodology for reading the meter and documenting the data, including all necessary billing determinants that will be provided to the utility. Both the department of energy and the utility shall endeavor to review the methodology as expeditiously as possible, and the electric utility customer account of record at the point of interconnection may identify its concerns, if any. If either the department of energy or the utility rejects the proposed process, such rejection shall be adequately specific so that the hydroelectric generator may make the changes necessary to receive approval. Upon approval of the process, the hydroelectric generator shall assume liability for monthly meter reads and providing all requisite billing determinants and other necessary data to the utility for billing purposes, including issuing net metering credits. The utility shall bill according to the information received from the hydroelectric generator, but shall not be liable for the accuracy of meter reads or the ongoing maintenance and performance of the meter. The hydroelectric generator getting billed and receiving credits pursuant to this provision shall be subject to periodic audits of the documentation and records associated with the meter reading process to ensure compliance with all statutes, rules and tariffs. Audits will be conducted on an as-needed basis, and may be requested by the electric utility customer account of record, but no more frequently than annually, which shall be determined and authorized by the department of energy, and conducted by the utility. The***

Commented [CB26]: This entire paragraph was repealed and reenacted by [Chapter 141, NH Laws of 2023](SB 40) effective 6/30/23. The bold text is the new text.

audit results shall be provided to the electric utility customer account of record at the point of interconnection to the electric grid. The hydroelectric generator shall be responsible for all meter costs, including those for ongoing operation and maintenance, as well as all audit costs. The utility shall recover the incremental costs for this manual billing process, as well as all net metering credits issued pursuant to this provision from all utility customers. Nothing in this paragraph shall be deemed to approve or allow the participation of energy storage facilities in net energy metering unless otherwise approved or allowed by law or an order or decision issued or rule adopted by the department of energy or the public utilities commission.

XXI. (a) **The commission shall consider the question of whether or not exports to the grid by customer-generators taking default service should be accounted for as reduction to what would otherwise be the wholesale load obligation of the load serving entity providing default service absent such exports to the grid. The commission shall use its best efforts to resolve such question through an order in an adjudicated proceeding, which may be DE 16-576, issued no later than June 15, 2022.**

(b) No generator of greater than one megawatt total peak generating capacity that first becomes operational after July 1, 2021 that elects to participate in net metering as otherwise authorized by statute shall be registered as a generator asset with ISO New England before June 30, 2022.

(c) A generator of greater than one megawatt total peak generating capacity that first became operational before July 1, 2021 that elects to participate in net metering as otherwise authorized by statute and that is registered with ISO New England as a generator asset may, at its discretion, retire from such participation in ISO New England wholesale markets.

XXII. No later than January 1, 2023, the electric distribution utilities shall publish on their websites a hosting capacity map showing the estimated maximum amount of distributed generation that can be accommodated on the distribution system at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability, or other operational criteria, and without requiring significant infrastructure upgrades. The maps shall provide relevant electrical information regarding the circuit and affiliated substation for each location, including interconnected and queued distributed generation, and shall be updated regularly.

XXIII. **When the department of energy's distributed energy resource valuation study is completed and thereafter the public utilities commission opens a new proceeding that includes consideration of the adoption of net metering tariffs that apply to newly-constructed customer-generators with a total peak generating capacity of greater than one megawatt,** the commission shall consider whether and when further changes should be made to the net metering tariff structure approved in order no. 26,029 issued on June 23, 2017, applicable to such newly-constructed customer-generators. **Such consideration** of net metering tariffs that apply to newly-constructed customer-generators with a total peak generating capacity of greater than one megawatt **shall include but not be limited to whether or not the cost of compliance with the electric renewable portfolio**

Commented [CB27]: This whole paragraph was added by 2021, Chapter 228:2 (SB 91, Part II).

Commented [CB28]: This paragraph was added by 2022, Chapter 328 (SB 262).

Commented [CB29]: This was enacted by HB 1599, 2022 Chapter 308, eff. 8/30/22. In its OON in DE 22-060 the PUC noted that these matters are within the scope of this proceeding. (p. 2)

standard, RSA 362-F, inclusive of prior period reconciliations, <u>should be excluded from the monetary credit for exports to the grid,</u> as well as **<u>whether or not</u> <u>the monetary credit should include compensation for services and value currently not compensated such as avoided transmission, distribution, and capacity costs and other grid services.</u>**

Source. 1998, 261:10. 2000, 148:1, 2. 2007, 174:2-4, eff. Aug. 17, 2007. 2010, 143:3, eff. Aug. 13, 2010. 2011, 168:3, eff. July 1, 2011. 2012, 59:1, eff. July 13, 2012. 2013, 266:2, eff. July 24, 2013. 2016, 31:3-5; 33:1, 2, eff. May 2, 2016; 33:3 eff. as provided by 2016, 33:4. 2017, 226:7, 8, eff. July 11, 2017. 2018, 112:1, eff. July 24, 2018; 212:2, eff. Aug. 7, 2018; 212:3, eff. July 24, 2018 at 12:01 a.m. 2019, 271:2, eff. July 1, 2019. 2020, 21:1, eff. Sept. 15, 2020. 2021, 91:233, 234, eff. July 1, 2021; 228:2, Pt. II, Secs. 1-3, eff. Aug. 26, 2021; 228:2, Pt. III, Sec. 1, eff. Oct. 25, 2021. 2022, 152:1, 2, eff. Aug. 6, 2022; 308:1, eff. Aug. 30, 2022; 328:1, 3, eff. Sept. 6, 2022; 329:1, eff. Sept. 6, 2022; 2023, 141:1 eff. June 30, 2023, 166:1, eff. July 28, 2023..

Attachment D: List of Members

The following entities are Parties to the Joint Power Agreement of Community Power Coalition of New Hampshire:

1. City of Lebanon
2. Town of Hanover
3. City of Nashua
4. Cheshire County
5. Town of Harrisville
6. Town of Exeter
7. Town of Rye
8. City of Dover
9. Town of Warner
10. Town of Walpole
11. Town of Plainfield
12. Town of Newmarket
13. Town of Enfield
14. Town Durham
15. Town of Pembroke (10/21/21)[3]
16. Town of Hudson (12/16/21)
17. Town of Webster (12/16/21
18. Town of New London (1/20/22)
19. City of Portsmouth (4/21/22)
20. Town of Peterborough (7/28/22)
21. Town of Canterbury (10/20/22)
22. Town of Wilmot (10/20/22)
23. Town of Sugar Hill (11/17/22)
24. Town of Hancock (11/17/22)
25. Town of Westmoreland (12/19/22)
26. Town of Shelburne (12/19/22)
27. Town of Boscawen (1/31/23)
28. City of Berlin (3/16/23
29. Town of Randolph (3/16/23)
30. Town of Rollinsford (4/21/23)
31. Town of Lyme (4/21/23)
32. Town of Stratham (4/21/23)
33. Town of Newport (5/25/23)
34. Town of Campton (6/30/23)
35. Town of Barrington (7/27/23)
36. Town of Loudon (8/31/23)
37. Town of Northfield (8/31/23)
38. City of Somersworth (9/27/23)
39. Town of Tamworth (9/27/23)
40. Town of Hopkinton (9/27/23)
41. Town of Atkinson (9/27/23)
42. Town of Bradford (10/26/23)
43. Town of Grantham (10/26/23
44. Town of Bethlehem (10/16/23)
45. Town of Gilford (11/30/23)
46. Town of Hampton Falls (11/30/23)
47. Town of Franconia (11/30/23)
48. Town of Kensington (11/30/23)
49. Town of Lancaster (11/30/23)

[3] The dates for Members joining after 10/1/21 are the dates the Board of Directors approved the new Member and their Membership became effective per Article IV, Section 4 of this JPA and Section 3.5 of the By-Laws.

	A	B	C	D	E	F	I	J	K	L	M	N
1	AVOIDED TRANSMISSION COST MODEL						1. ISO NE NH BTM PV Estimate			2. LU interval metered NEM		
2	by Clifton Below for CPCNH, 12/4/23											
3		2022 % on T peaks, RNS Avoided Cost/kWh						0.08%	$ 0.0096		0.09%	$ 0.0106
4		2021 % on T peaks, RNS Avoided Cost/kWh						0.13%	$ 0.0154		0.11%	$ 0.0129
5	Year	MO.	Day	Hour Ending	RNS, LNS or both	RNS rate $/kW-mo.	NH BTM PV MW	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value
6	Totals for Year 2022						209,111	169	$ 2,009,096	1,669,982	1,500	$ 17,780
7	Totals for Year 2021						157,982	209	$ 2,429,441	1,249,987	1376.467	$ 16,091
8	2021	1	1	1			0	0	$ -	0	0	$ -
9	2021	1	1	2			0	0	$ -	0	0	$ -
10	2021	1	1	3			0	0	$ -	0	0	$ -
11	2021	1	1	4			0	0	$ -	0	0	$ -
12	2021	1	1	5			0	0	$ -	0	0	$ -
13	2021	1	1	6			0	0	$ -	0	0	$ -
14	2021	1	1	7			0	0	$ -	0	0	$ -
15	2021	1	1	8			1.2	0	$ -	0	0	$ -
16	2021	1	1	9			16.7	0	$ -	50.105	0	$ -
17	2021	1	1	10			40.2	0	$ -	295.473	0	$ -
18	2021	1	1	11			55.7	0	$ -	435.813	0	$ -
19	2021	1	1	12			57.3	0	$ -	418.705	0	$ -
20	2021	1	1	13			44	0	$ -	293.278	0	$ -
21	2021	1	1	14			27.9	0	$ -	118.192	0	$ -
22	2021	1	1	15			13.3	0	$ -	24.013	0	$ -
23	2021	1	1	16			4	0	$ -	0.333	0	$ -
24	2021	1	1	17			0	0	$ -	0	0	$ -
25	2021	1	1	18			0	0	$ -	0	0	$ -
26	2021	1	1	19			0	0	$ -	0	0	$ -
27	2021	1	1	20			0	0	$ -	0	0	$ -
28	2021	1	1	21			0	0	$ -	0	0	$ -
29	2021	1	1	22			0	0	$ -	0	0	$ -
30	2021	1	1	23			0	0	$ -	0	0	$ -
31	2021	1	1	24			0	0	$ -	0	0	$ -

	A	B	C	D	O	P	Q	R	S	T	U	V	W
1	AVOIDED TRANSMISSION CO:				3. UES interval metered NEM			4. Eversource 10 large PV			5. Eversource 10 large Hydros		
2	by Clifton Below for CPCNH, 1							2022 Data Only			2022 Data Only		
3	2022 % on T peaks,					0.11%	$ 0.0129		0.08%	$ 0.0094		0.13%	$ 0.0149
4	2021 % on T peaks,					0.13%	$ 0.0151						
5	Year	MO.	Day	Hour Ending	kWh	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value
6	Totals for Year 2022				12,087,367	13,117	$ 155,987.10	5,807,540	4,609	$ 54,672	16,886,125	21,138	$ 251,272
7	Totals for Year 2021				316,436	409.73	$ 4,770.87						
8	2021	1	1	1	0	0	$ -						
9	2021	1	1	2	0	0	$ -						
10	2021	1	1	3	0	0	$ -						
11	2021	1	1	4	0	0	$ -						
12	2021	1	1	5	0	0	$ -						
13	2021	1	1	6	0	0	$ -						
14	2021	1	1	7	0	0	$ -						
15	2021	1	1	8	0	0	$ -						
16	2021	1	1	9	0	0	$ -						
17	2021	1	1	10	32.02	0	$ -						
18	2021	1	1	11	81.11	0	$ -						
19	2021	1	1	12	86.77	0	$ -						
20	2021	1	1	13	41.2	0	$ -						
21	2021	1	1	14	20	0	$ -						
22	2021	1	1	15	1.918	0	$ -						
23	2021	1	1	16	0	0	$ -						
24	2021	1	1	17	0	0	$ -						
25	2021	1	1	18	0	0	$ -						
26	2021	1	1	19	0	0	$ -						
27	2021	1	1	20	0	0	$ -						
28	2021	1	1	21	0	0	$ -						
29	2021	1	1	22	0	0	$ -						
30	2021	1	1	23	0	0	$ -						
31	2021	1	1	24	0	0	$ -						

	A	B	C	D	X	Y	Z	AA	AB	AC	AD	AE	AF
1	AVOIDED TRANSMISSION CO:				6. Eversource 7 NEM over 1 MW			7. DOE Avoided Cost Calculation Data			8. Ten Dual Axis Trackers in NH		
2	by Clifton Below for CPCNH, 1				2022 Data Only			Average of several NH systems					
3	2022 % on T peaks,					0.14%	$ 0.0167		0.15%	$ 0.0173		0.12%	$ 0.0139
4	2021 % on T peaks,								0.15%	$ 0.0176		0.11%	$ 0.0129
5	Year	MO.	Day	Hour Ending	kWh	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value
6	Totals for Year 2022				47,250,720	66,214	$ 787,246	1,193,022	1,743	$ 20,680.57	79,920	93	$ 1,108
7	Totals for Year 2021							204,484	310.888	$ 3,602.93	70,239	77	$ 903
8	2021	1	1	1				0	0	$ -	0	0	$ -
9	2021	1	1	2				0	0	$ -	0	0	$ -
10	2021	1	1	3				0	0	$ -	0	0	$ -
11	2021	1	1	4				0	0	$ -	0	0	$ -
12	2021	1	1	5				0	0	$ -	0	0	$ -
13	2021	1	1	6				0	0	$ -	0	0	$ -
14	2021	1	1	7				0	0	$ -	0	0	$ -
15	2021	1	1	8				2.65	0	$ -	0.3	0	$ -
16	2021	1	1	9				16.588	0	$ -	7.1	0	$ -
17	2021	1	1	10				42.768	0	$ -	17.4	0	$ -
18	2021	1	1	11				57.498	0	$ -	21.1	0	$ -
19	2021	1	1	12				56.46	0	$ -	18	0	$ -
20	2021	1	1	13				41.225	0	$ -	12.6	0	$ -
21	2021	1	1	14				26.555	0	$ -	7.5	0	$ -
22	2021	1	1	15				11.338	0	$ -	2.6	0	$ -
23	2021	1	1	16				3.003	0	$ -	0.5	0	$ -
24	2021	1	1	17				0.02	0	$ -	0	0	$ -
25	2021	1	1	18				0	0	$ -	0	0	$ -
26	2021	1	1	19				0	0	$ -	0	0	$ -
27	2021	1	1	20				0	0	$ -	0	0	$ -
28	2021	1	1	21				0	0	$ -	0	0	$ -
29	2021	1	1	22				0	0	$ -	0	0	$ -
30	2021	1	1	23				0	0	$ -	0	0	$ -
31	2021	1	1	24				0	0	$ -	0	0	$ -

	A	B	C	D	AG	AH	AI	AJ	AK	AL
1	AVOIDED TRANSMISSION CO!				9. Two Dual Axis Trackers in Leb.			10. Hypothetical LFGTE		
2	by Clifton Below for CPCNH, 1				4/1/21 to 3/31/22 only			Equal production all hours		
3		2022 % on T peaks,							0.14%	$ 0.0163
4		2021 % on T peaks,				0.14%	$ 0.0163		0.14%	$ 0.0155
5	Year	MO.	Day	Hour Ending	watts	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value
6	Totals for Year 2022				-	-	$ -	7,008,000	9,600	$ 114,104
7	Totals for Year 2021				12,885,749	17,989	$ 209	7,008,000	9,600	$ 108,878
8	2021	1	1	1				800	0	$ -
9	2021	1	1	2				800	0	$ -
10	2021	1	1	3				800	0	$ -
11	2021	1	1	4				800	0	$ -
12	2021	1	1	5				800	0	$ -
13	2021	1	1	6				800	0	$ -
14	2021	1	1	7				800	0	$ -
15	2021	1	1	8				800	0	$ -
16	2021	1	1	9				800	0	$ -
17	2021	1	1	10				800	0	$ -
18	2021	1	1	11				800	0	$ -
19	2021	1	1	12				800	0	$ -
20	2021	1	1	13				800	0	$ -
21	2021	1	1	14				800	0	$ -
22	2021	1	1	15				800	0	$ -
23	2021	1	1	16				800	0	$ -
24	2021	1	1	17				800	0	$ -
25	2021	1	1	18				800	0	$ -
26	2021	1	1	19				800	0	$ -
27	2021	1	1	20				800	0	$ -
28	2021	1	1	21				800	0	$ -
29	2021	1	1	22				800	0	$ -
30	2021	1	1	23				800	0	$ -
31	2021	1	1	24				800	0	$ -

	A	B	C	D	E	F	I	J	K	L	M	N	O
1	AVOIDED TRANSMISSION COST MODEL						1. ISO NE NH BTM PV Estimate			2. LU interval metered NEM			3. UES ir
2	by Clifton Below for CPCNH, 12/4/23												
3		2022 % on T peaks, RNS Avoided Cost/kWh						0.08%	$ 0.0096		0.09%	$ 0.0106	
4		2021 % on T peaks, RNS Avoided Cost/kWh						0.13%	$ 0.0154		0.11%	$ 0.0129	
5	Year	MO.	Day	Hour Ending	RNS, LNS or both	RNS rate $/kW-mo.	NH BTM PV MW	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value	kWh
6	Totals for Year 2022						209,111	169	$ 2,009,096	1,669,982	1,500	$ 17,780	12,087,367
7	Totals for Year 2021						157,982	209	$ 2,429,441	1,249,987	1376.467	$ 16,091	316,436
12994	2022	6	25	24			0	0	$ -	0	0	$ -	861.861
12995	2022	6	26	1			0	0	$ -	0	0	$ -	869.869
12996	2022	6	26	2			0	0	$ -	0	0	$ -	854.854
12997	2022	6	26	3			0	0	$ -	0	0	$ -	911.911
12998	2022	6	26	4			0	0	$ -	0	0	$ -	910.91
12999	2022	6	26	5			0	0	$ -	0	0	$ -	933.933
13000	2022	6	26	6			1.3	0	$ -	3.22	0	$ -	942.984
13001	2022	6	26	7			10.5	0	$ -	20.275	0	$ -	960.447
13002	2022	6	26	8			34.7	0	$ -	237.75	0	$ -	991.395
13003	2022	6	26	9			64.1	0	$ -	602.551	0	$ -	1036.053
13004	2022	6	26	10			91.1	0	$ -	951.151	0	$ -	1188.355
13005	2022	6	26	11			111.2	0	$ -	1288.136	0	$ -	1324.201
13006	2022	6	26	12			122.8	0	$ -	1358.35	0	$ -	1373.764
13007	2022	6	26	13			125.1	0	$ -	1293.185	0	$ -	1329.15
13008	2022	6	26	14			117.4	0	$ -	1215.183	0	$ -	1301.425
13009	2022	6	26	15			110.2	0	$ -	1280.934	0	$ -	1317.446
13010	2022	6	26	16			95	0	$ -	1051.491	0	$ -	1237.067
13011	2022	6	26	17			73	0	$ -	806.844	0	$ -	944.968
13012	2022	6	26	18	both	11.8983	45.5	45.5	$ 541,373	441.254	441.254	$ 5,250	992.54
13013	2022	6	26	19			21.8	0	$ -	124.735	0	$ -	874.275
13014	2022	6	26	20			4.8	0	$ -	13.11	0	$ -	778.65
13015	2022	6	26	21			0.1	0	$ -	0.97	0	$ -	761.761
13016	2022	6	26	22			0	0	$ -	0	0	$ -	770.77
13017	2022	6	26	23			0	0	$ -	0	0	$ -	764.764
13018	2022	6	26	24			0	0	$ -	0	0	$ -	750.75
13019	2022	6	27	1			0	0	$ -	0	0	$ -	709.709

	A	B	C	D	P	Q	R	S	T	U	V	W
1	AVOIDED TRANSMISSION CO				terval metered NEM		4. Eversource 10 large PV			5. Eversource 10 large Hydros		
2	by Clifton Below for CPCNH, 1						2022 Data Only			2022 Data Only		
3		2022	% on T peaks,		0.11%	$ 0.0129		0.08%	$ 0.0094		0.13%	$ 0.0149
4		2021	% on T peaks,		0.13%	$ 0.0151						
5	Year	MO.	Day	Hour Ending	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value
6	Totals for Year 2022				13,117	$ 155,987.10	5,807,540	4,609	$ 54,672	16,886,125	21,138	$ 251,272
7	Totals for Year 2021				409.73	$ 4,770.87						
12994	2022	6	25	24	0	$ -	0	0	$ -	645.7988	0	$ -
12995	2022	6	26	1	0	$ -	0	0	$ -	633.5938	0	$ -
12996	2022	6	26	2	0	$ -	0	0	$ -	624.8425	0	$ -
12997	2022	6	26	3	0	$ -	0	0	$ -	623.47	0	$ -
12998	2022	6	26	4	0	$ -	0	0	$ -	623.965	0	$ -
12999	2022	6	26	5	0	$ -	0	0	$ -	622.9738	0	$ -
13000	2022	6	26	6	0	$ -	25.135	0	$ -	615.2712	0	$ -
13001	2022	6	26	7	0	$ -	166.4125	0	$ -	615.3725	0	$ -
13002	2022	6	26	8	0	$ -	828.8825	0	$ -	611.83	0	$ -
13003	2022	6	26	9	0	$ -	1899.6325	0	$ -	611.475	0	$ -
13004	2022	6	26	10	0	$ -	2868.2325	0	$ -	608.3188	0	$ -
13005	2022	6	26	11	0	$ -	3492.545	0	$ -	601.975	0	$ -
13006	2022	6	26	12	0	$ -	3693.9275	0	$ -	593.7525	0	$ -
13007	2022	6	26	13	0	$ -	3749.5575	0	$ -	594.1725	0	$ -
13008	2022	6	26	14	0	$ -	3620.72	0	$ -	594.155	0	$ -
13009	2022	6	26	15	0	$ -	3562.765	0	$ -	594.3525	0	$ -
13010	2022	6	26	16	0	$ -	3246.9175	0	$ -	595.9075	0	$ -
13011	2022	6	26	17	0	$ -	2416.695	0	$ -	589.385	0	$ -
13012	2022	6	26	18	992.54	$ 11,809.54	1440.1575	1440.158	$ 17,135	578.625	578.625	$ 6,885
13013	2022	6	26	19	0	$ -	422.2275	0	$ -	576.3012	0	$ -
13014	2022	6	26	20	0	$ -	67.8425	0	$ -	575.83	0	$ -
13015	2022	6	26	21	0	$ -	5.8	0	$ -	583.5925	0	$ -
13016	2022	6	26	22	0	$ -	0	0	$ -	582.73	0	$ -
13017	2022	6	26	23	0	$ -	0	0	$ -	586.7438	0	$ -
13018	2022	6	26	24	0	$ -	0	0	$ -	584.4575	0	$ -
13019	2022	6	27	1	0	$ -	0	0	$ -	586.085	0	$ -

	A	B	C	D	X	Y	Z	AA	AB	AC	AD	AE	AF
1	AVOIDED TRANSMISSION CO:				6. Eversource 7 NEM over 1 MW			7. DOE Avoided Cost Calculation Data			8. Ten Dual Axis Trackers in NH		
2	by Clifton Below for CPCNH, 1				2022 Data Only			Average of several NH systems					
3	2022 % on T peaks,					0.14%	$ 0.0167		0.15%	$ 0.0173		0.12%	$ 0.0139
4	2021 % on T peaks,								0.15%	$ 0.0176		0.11%	$ 0.0129
5	Year	MO.	Day	Hour Ending	kWh	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value
6	Totals for Year 2022				47,250,720	66,214	$ 787,246	1,193,022	1,743	$ 20,680.57	79,920	93	$ 1,108
7	Totals for Year 2021							204,484	310.888	$ 3,602.93	70,239	77	$ 903
12994	2022	6	25	24	2504.2063	0	$ -	0	0	$ -	0.0	0	$ -
12995	2022	6	26	1	2501.3188	0	$ -	0	0	$ -	0.0	0	$ -
12996	2022	6	26	2	2507.4	0	$ -	0	0	$ -	0.0	0	$ -
12997	2022	6	26	3	2495.5875	0	$ -	0	0	$ -	0.0	0	$ -
12998	2022	6	26	4	2479.75	0	$ -	0	0	$ -	0.0	0	$ -
12999	2022	6	26	5	2447.9438	0	$ -	0	0	$ -	0.0	0	$ -
13000	2022	6	26	6	2443.0437	0	$ -	0.05	0	$ -	0.5	0	$ -
13001	2022	6	26	7	2429.35	0	$ -	0.443	0	$ -	8.5	0	$ -
13002	2022	6	26	8	2419.375	0	$ -	132.303	0	$ -	23.2	0	$ -
13003	2022	6	26	9	2414.2125	0	$ -	294.249	0	$ -	35.8	0	$ -
13004	2022	6	26	10	2403.7563	0	$ -	493.304	0	$ -	38.3	0	$ -
13005	2022	6	26	11	2390.2375	0	$ -	634.504	0	$ -	39.4	0	$ -
13006	2022	6	26	12	2367.4	0	$ -	731.383	0	$ -	40.1	0	$ -
13007	2022	6	26	13	2349.55	0	$ -	784.078	0	$ -	39.1	0	$ -
13008	2022	6	26	14	2368.975	0	$ -	788.331	0	$ -	38.8	0	$ -
13009	2022	6	26	15	2354.625	0	$ -	728.603	0	$ -	38.4	0	$ -
13010	2022	6	26	16	2132.55	0	$ -	666.494	0	$ -	35.1	0	$ -
13011	2022	6	26	17	2146.6375	0	$ -	551.351	0	$ -	35.0	0	$ -
13012	2022	6	26	18	2223.725	2223.725	$ 26,459	406.972	406.972	$ 4,842.27	27.9	27.856	$ 331
13013	2022	6	26	19	2272.1562	0	$ -	218.702	0	$ -	16.4	0	$ -
13014	2022	6	26	20	2273.1625	0	$ -	0.157	0	$ -	4.1	0	$ -
13015	2022	6	26	21	2281.5625	0	$ -	0	0	$ -	0.2	0	$ -
13016	2022	6	26	22	2274.3	0	$ -	0	0	$ -	0.0	0	$ -
13017	2022	6	26	23	2139.1563	0	$ -	0	0	$ -	0.0	0	$ -
13018	2022	6	26	24	2133.95	0	$ -	0	0	$ -	0.0	0	$ -
13019	2022	6	27	1	2271.5	0	$ -	0	0	$ -	0.0	0	$ -

	A	B	C	D	AG	AH	AI	AJ	AK	AL
1	AVOIDED TRANSMISSION CO!				9. Two Dual Axis Trackers in Leb.			10. Hypothetical LFGTE		
2	by Clifton Below for CPCNH, 1				4/1/21 to 3/31/22 only			Equal production all hours		
3	2022 % on T peaks,								0.14%	$ 0.0163
4	2021 % on T peaks,					0.14%	$ 0.0163		0.14%	$ 0.0155
5	Year	MO.	Day	Hour Ending	watts	On RNS peak	Value/kWh Value	kWh	On RNS peak	Value/kWh Value
6	Totals for Year 2022				-	-	$ -	7,008,000	9,600	$ 114,104
7	Totals for Year 2021				12,885,749	17,989	$ 209	7,008,000	9,600	$ 108,878
12994	2022	6	25	24				800	0	$ -
12995	2022	6	26	1				800	0	$ -
12996	2022	6	26	2				800	0	$ -
12997	2022	6	26	3				800	0	$ -
12998	2022	6	26	4				800	0	$ -
12999	2022	6	26	5				800	0	$ -
13000	2022	6	26	6				800	0	$ -
13001	2022	6	26	7				800	0	$ -
13002	2022	6	26	8				800	0	$ -
13003	2022	6	26	9				800	0	$ -
13004	2022	6	26	10				800	0	$ -
13005	2022	6	26	11				800	0	$ -
13006	2022	6	26	12				800	0	$ -
13007	2022	6	26	13				800	0	$ -
13008	2022	6	26	14				800	0	$ -
13009	2022	6	26	15				800	0	$ -
13010	2022	6	26	16				800	0	$ -
13011	2022	6	26	17				800	0	$ -
13012	2022	6	26	18				800	800	$ 9,519
13013	2022	6	26	19				800	0	$ -
13014	2022	6	26	20				800	0	$ -
13015	2022	6	26	21				800	0	$ -
13016	2022	6	26	22				800	0	$ -
13017	2022	6	26	23				800	0	$ -
13018	2022	6	26	24				800	0	$ -
13019	2022	6	27	1				800	0	$ -

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 22-060

Date Request Received: November 01, 2023 **Date of Response: November 09, 2023**
Data Request No. CPCNH 2-002 **Page 1 of 1**

Request from: Community Power Coalition of New Hampshire

Witness: Swift, Joseph R

Request:

(for each utility): Is it possible for the loss adjustment factor between retail meter loads and generation supplied over the LNS and RNS to go negative, if exports to the grid by net metered generation that does not sell its power into the ISO-NE wholesale market and thus is treated as a load reducer under applicable tariffs and policies? In other words, is it possible that the apparent line losses on the distribution grid could go negative, such that less power is being purchased and delivered to the distribution grid through ISO-New England than is being consumed at retail, due to otherwise unaccounted for NEM exports to the distribution grid?

Response:

Yes, the apparent loss factors between the generation supplied over the LNS and retail loads are negative for some hours. That is, for some hours the wholesale loads measured at the LNS are lower than retail loads reported at customers′ meters. While unaccounted NEM exports to the distribution grid (load reducers) will have a downward impact on apparent line losses, there are other substantial contributing factors to apparent line losses including differences between estimates of customer usage based on hourly rate class profiles used in load settlement calculations and actual customer energy usage.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 22-060

Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators

Community Power Coalition of New Hampshire Data Requests - Set 2

Date Request Received: 11/1/23
Request No: CPCNH 2-2

Date of Response: 11/29/23
Respondent: Jesse Wooster

REQUEST:

Is it possible for the loss adjustment factor between retail meter loads and generation supplied over the LNS and RNS to go negative, if exports to the grid by net metered generation that does not sell its power into the ISO-NE wholesale market and thus is treated as a load reducer under applicable tariffs and policies? In other words, is it possible that the apparent line losses on the distribution grid could go negative, such that less power is being purchased and delivered to the distribution grid through ISO-New England than is being consumed at retail, due to otherwise unaccounted for NEM exports to the distribution grid?

RESPONSE:

Yes, the apparent line losses could appear negative due to unaccounted NEM exports to the distribution grid and other contributing factors such as differences between estimates of customer usage based on hourly rate class profiles used in load settlement calculations and actual customer energy usage.

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 22-060

Date Request Received: November 13, 2023 **Date of Response: November 29, 2023**
Data Request No. OCA 2-014 **Page 1 of 1**

Request from: Office of Consumer Advocate

Witness: Davis, Edward A

Request:

Please provide the following hourly profiles (8760 hours in year) for 2018-2022 in Microsoft Excel. If the data requested are not available, please provide the data that most closely match that requested.

a. Average per-customer load profile (*i.e. total load divided by total customers*) for all residential customers.
b. Average per-customer load profile for all residential customers with distributed solar.
c. Average per-customer hourly exports profile for all residential customers with distributed solar.
d. Average per-customer hourly self-consumption profile for all residential customers with distributed solar. If this is not available, please provide the estimated percent of self-consumption for residential customers.
e. Average per-customer hourly total generation, absent any netti ng of load, for residential customers with distributed solar.
f. Average per-customer load profile for all residential customers without distributed solar.
g. Average per-customer load profile for all residential customers with distributed solar plus storage.
h. Average per-customer hourly export profile for all residential customer with distributed solar plus storage.

Response:

a. Average per-customer load profiles for residential Rate R for the period 2018-2021 are included as Attachment OCA 2-014. 2022 data is not yet available.

b-h. Eversource does not have separate interval meters and profiles for such residential customers, and therefore does not have this information. Use of data from part a. might provide a starting point from which to estimate such information.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 22-060

Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators

Office of the Consumer Advocate Data Requests - Set 3

Date Request Received: 11/15/23
Request No: OCA 3-12

Date of Response: 11/30/23
Respondent: Robert Garcia

REQUEST:

Please provide the following hourly profiles (8760 hours in year) for 2018-2022 in Microsoft Excel. If the data requested are not available, please provide the data that most closely match that requested.

a. Average per-customer load profile (i.e. total load divided by total customers) for all residential customers.
b. Average per-customer load profile for all residential customers with distributed solar.
c. Average per-customer hourly exports profile for all residential customers with distributed solar.
d. Average per-customer hourly self-consumption profile for all residential customers with distributed solar. If this is not available, please provide the estimated percent of self-consumption for residential customers.
e. Average per-customer hourly total generation, absent any ne□ng of load, for residential customers with distributed solar.
f. Average per-customer load profile for all residential customers without distributed solar.
g. Average per-customer load profile for all residential customers with distributed solar plus storage.
h. Average per-customer hourly export profile for all residential customer with distributed solar plus storage.

RESPONSE:

a. Please see Attachment 22-060 OCA 3-12.xlsx.
b. No separate load profile is generated for this classification.
c. No separate load profile is generated for this classification.
d. No separate load profile is generated for this classification

e. No separate load profile is generated for this classification.

f. No separate load profile is generated for this classification.

g. No separate load profile is generated for this classification.

h. No separate load profile is generated for this classification.

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
Docket No. DE 22-060
Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators

Data Requests of the Office of the Consumer Advocate to the Joint Utilities, Set 3
October 18, 2023

Data Request 3-12:

Please provide the following hourly profiles (8760 hours in year) for 2018-2022 in Microsoft Excel. If the data requested are not available, please provide the data that most closely match that requested.

a. Average per-customer load profile (*i.e. total load divided by total customers*) for all residential customers.

b. Average per-customer load profile for all residential customers with distributed solar.

c. Average per-customer hourly exports profile for all residential customers with distributed solar.

d. Average per-customer hourly self-consumption profile for all residential customers with distributed solar. If this is not available, please provide the estimated percent of self-consumption for residential customers.

e. Average per-customer hourly total generation, absent any netting of load, for residential customers with distributed solar.

f. Average per-customer load profile for all residential customers without distributed solar.

g. Average per-customer load profile for all residential customers with distributed solar plus storage.

h. Average per-customer hourly export profile for all residential customer with distributed solar plus storage.

Response:

a. The Company is unable to directly provide this information. For purposes of this response, the load for each hour is divided by the number of residential customers in each month so there may be a mismatch between hourly and monthly data. Please see OCA 3-12 Attachment 1 for this calculation.
b. The Company does not track load profiles for customers with distributed solar.

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
Docket No. DE 22-060
Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators

Data Requests of the Office of the Consumer Advocate to the Joint Utilities, Set 3
October 18, 2023

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c. The Company does not track hourly exports for residential customers.
d. The Company does not have the requested information.
e. The Company does not track hourly total generation for residential customers with distributed solar.
f. The requested information is not available.
g. The Company does not have load profile information for all residential customers with distributed solar plus storage.
h. The Company does not have hourly exports for all residential customers with distributed solar plus storage.

Witness: K. Asbury / E. Leake **Date:** November 30, 2023

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 22-060

Date Request Received: November 01, 2023 **Date of Response: November 09, 2023**
Data Request No. CPCNH 2-003 **Page 1 of 2**

Request from: Community Power Coalition of New Hampshire

Witness: Burnham, David J, Swift, Joseph R, Rice, Brian J

Request:

(Eversource) RE: Eversource Response to CPCNH 1-003(d): Eversource indicated that they hold “49 ISO-NE asset ID numbers for which the Company receives generation and capacity payment.”

a) Are there any additional NEM customer-generators for which Eversource receives ONLY generation payment and not capacity payments?
b) Of the 49 identified, how many were registered as “Generators” or market participants with ISO New England before becoming net metered customer-generators, and not in conjunction with net metering, and how many were registered with ISO-NE in conjunction with or after becoming NEM customer-generators?
c) Does Eversource require some or all of these net metered customer-generators to remain registered with ISO-NE as Generators? If so how many and why?
d) Has Eversource ever expressly sought or been given New Hampshire PUC permission to have state jurisdictional net metered customer-generators to continue to be or become with ISO-NE as “Generators” that sell power into the FERC jurisdictional interstate wholesale electricity market?
e) Does Eversource require some of all of these customer-generators to bid their capacity into the ISO NE forward capacity market? If so, how many?
f) Please identify how many of these 49 customers generators are hydroelectric facilities, PV facilities, or other types of generation (e.g. wind, landfill gas, methane gas, CHP, etc.).

Response:

a) Eversource is not aware of any additional ISO-NE-registered assets that are net metered customers for which Eversource receives generation but not capacity payments. The Company is still reviewing and will supplement this response should any differing information become available.

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 22-060

Date Request Received: November 01, 2023 **Date of Response: November 09, 2023**
Data Request No. CPCNH 2-003 **Page 2 of 2**

b) Eversource does not track information as to whether the 49 customer generators became net metered customers before or after registering as assets with ISO-NE.

c) The Company does not impose any requirements on net-metered, customer-generators to register with the ISO-NE.

d) Eversource is not aware that it specifically requested or was given express permission for net-metered customer-generators to be registered as generators with ISO-NE. However, the Commission approved a settlement agreement in Docket No. DE 20-136 which allowed for wholesale market revenue generated from net metered customers with facilities that are registered with ISO-NE as settlement only generators to be credited to customers through the Stranded Cost Recovery Charge.

e) The Company does not impose any requirements on net-metered, customer-generators to bid their capacity into the FCM.

f) The table below provides the generator type for the 49 generators.

Generator Type	Total
Hydroelectric	38
PV	10
Gas	1
Total	**49**

Public Service Company of New Hampshire
d/b/a Eversource Energy
Stranded Cost Recovery Charge (SCRC)
Net Metering Adder Recovery Analysis

Line #	Month/Year	NEM Expense to Customer Generators					
			Gross		Revenues		Net
	Col. A		Col. B		Col. C		Col. D
							Col. B - Col. C
1	Feb-20	$	777,081	$	82,202	$	694,879
2	Mar-20		832,998		111,398		721,600
3	Apr-20		1,198,515		135,206		1,063,308
4	May-20		927,492		110,112		817,380
5	Jun-20		789,060		42,545		746,515
6	Jul-20		715,782		48,532		667,250
7	Aug-20		684,318		31,074		653,243
8	Sep-20		608,068		19,817		588,251
9	Oct-20		651,134		60,752		590,382
10	Nov-20		654,942		67,380		587,562
11	Dec-20		792,688		203,827		588,861
12	Total 2020	$	8,632,077	$	912,845	$	7,719,232
13	Jan-21	$	756,529	$	203,288	$	553,242
14	Feb-21		672,506		242,694		429,812
15	Mar-21		808,755		198,562		610,193
16	Apr-21		1,286,754		146,468		1,140,287
17	May-21		1,103,260		153,070		950,190
18	Jun-21		909,500		116,044		793,455
19	Jul-21		918,452		194,366		724,086
20	Aug-21		1,369,147		236,247		1,132,900
21	Sep-21		1,388,339		216,545		1,171,794
22	Oct-21		955,265		210,496		744,770
23	Nov-21		1,071,755		292,246		779,509
24	Dec-21		1,177,471		296,851		880,620
25	Total 2021	$	12,417,734	$	2,506,878	$	9,910,856
26	Jan-22	$	554,529	$	344,643	$	209,886
27	Feb-22		1,012,813		494,081		518,731
28	Mar-22		1,824,816		521,488		1,303,328
29	Apr-22		2,840,412		454,679		2,385,733
30	May-22		2,356,823		547,666		1,809,157
31	Jun-22		1,817,383		318,621		1,498,763
32	Jul-22		1,608,012		204,430		1,403,582
33	Aug-22		2,478,979		216,671		2,262,308
34	Sep-22		2,798,072		167,769		2,630,304
35	Oct-22		3,107,519		242,793		2,864,726
36	Nov-22		3,482,471		449,094		3,033,377
37	Dec-22		4,463,410		1,135,768		3,327,642
38	Total 2022	$	28,345,240	$	5,097,704	$	23,247,536
39	Jan-23	$	5,471,063	$	619,048	$	4,852,015
40	Feb-23		6,076,714		541,863		5,534,851
41	Mar-23		4,436,225		309,460		4,126,765
42	Apr-23		6,634,233		327,238		6,306,996
43	May-23		4,485,066		234,901		4,250,165
44	Jun-23		4,432,543		227,650		4,204,893
45	Subtotal 2023	$	31,535,844	$	2,260,161	$	29,275,684
46	Grand Total	$	80,930,895	$	10,777,587	$	70,153,307

Public Service Company of New Hampshire d/b/a Eversource Energy
Stranded Cost Recovery Charge (SCRC)
Net Metering Adder Recovery Analysis

Line #	Year	NEM - Export Sales kWh			
		Billing System: C2		Billing System: NHLPB *	
		NEM 1.0 Standard Net Metering Tariff	NEM 2.0 Alternative Net Metering Tariff	NEM 2.0 Alternative Net Metering Tariff	
		Small Gen <= 100kW	Small Gen <= 100kW	Small Gen <= 100kW	Large Gen > 100kW
	Col. A	Col. B	Col. C	Col. D	Col. E
1	2018	23,402,017	5,777,343	1,100	-
2	2019	30,044,258	8,061,261	15,500	592,173
3	2020	19,575,966	6,331,068	-	7,051,813
4	2021	38,424,184	11,962,623	2,830	4,773,071
5	2022	50,298,125	14,363,079	-	7,678,101
6	2023 **	45,667,304	12,288,666	-	4,211,814
7	Grand Total	207,411,854	58,784,040	19,430	24,306,972

* NHLPB at this time does not have grandfathered NEM 1.0 Standard Net Metering EXPORT SALES kWh data within the core Billing System. A manual reporting process outside of the core Billing System would be needed to provide this data separately.

** as of August 2023