THE STATE OF NEW HAMPSHIRE BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

JOINT REBUTTAL TESTIMONY OF

Edward A. Davis, Brian J. Rice, Dawn Coskren, Joseph Swift and Colleen Bennett on behalf of PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

Karen M. Asbury, John J. Bonazoli, and Jeff Pentz on behalf of UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL, INC.

and

Robert Garcia, Dilip K. Kommineni and Laura Sasso on behalf of LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP. D/B/A LIBERTY

CONSIDERATION OF CHANGES TO THE CURRENT NET METERING TARIFF STRUCTURE, INCLUDING COMPENSATION OF CUSTOMER-GENERATORS

Docket No. DE 22-060

January 30, 2024

TABLE OF CONTENTS **BATES PAGE NO.**

I. INTRODUCTION & QUALIFICATIONS

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

A. My name is Edward A. Davis. My business address is 107 Selden Street, Berlin, CT 06037. My position is Director, Rates at Eversource Energy Service Company and in that position I provide rate and tariff related services to the operating companies of Eversource Energy including Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or "the Company").

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes. I have on many occasions testified before the Commission on behalf of Eversource, and at the state utility commissions in Connecticut and Massachusetts on behalf of other Eversource Energy affiliates on rate related matters.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with other Eversource witnesses as well as Unitil and Liberty witnesses. In that testimony, I summarize my educational and professional background.

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

A. My name is Brian J. Rice. My business address is 247 Station Drive, Westwood, MA 02090. My position is Director, Customer Solar Programs at Eversource Energy Service

Company and in that position I provide oversight of solar programs for Eversource customers in multiple New England states.

Q. Have you previously testified before the Commission?

A. Yes. I have on many occasions testified before the Commission on behalf of Eversource, and at the state utility commissions in Connecticut and Massachusetts on behalf of other Eversource Energy affiliates on rate related matters.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with other Eversource witnesses as well as Unitil and Liberty witnesses. In that testimony, I summarize my educational and professional background.

Q. Ms. Coskren, please state your name, business address, company position, and principal responsibilities in your current position.

A: My name is Dawn Coskren, I work at 73 West Brook Street in Manchester, New Hampshire. I work for Eversource Energy Service Company as Manager for Billing and Data Management for PSNH and Eversource Energy's affiliate in Western Massachusetts. In this role I'm responsible for managing activities associated with billing and meter data management of Eversource Energy and establishing practices to ensure that accurate bills are issued in a timely manner.

Q. Have you previously testified before the Commission?

A. Yes. I have on many occasions testified before the Commission on behalf of Eversource, and at the state utility commissions in Connecticut and Massachusetts on behalf of other Eversource Energy affiliates on rate related matters.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with other Eversource witnesses as well as Unitil and Liberty witnesses. In that testimony, I summarize my educational and professional background.

Q. Ms. Bennett, please state your name, business address, company position, and principal responsibilities in your current position.

A: My name is Colleen Bennett, I work at 107 Selden Street, Berlin, CT 06037. My position is Manager, Load Settlement and Analysis, at Eversource Energy Service Company and in that position I provide load settlement and load research services to the operating companies of Eversource Energy including Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or "the Company").

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Hartford in 2004 with Bachelor of Science in Business Administration from the University of Hartford. After interning with the company since 2001 in Finance and Business Performance at the affiliate Northeast Generation Services, I joined the load research department at Northeast Utilities full time upon graduation. I held various roles in load research with increasing responsibility until July 2022 when I was named to my current position, adding load settlement to my area of responsibility.

Q. Have you previously testified before the Commission?

A. No I have not.

Q. Mr. Swift, please state your name, business address, company position, and principal responsibilities in your current position.

A: My name is Joseph Swift, I work at 107 Selden Street, Berlin, CT 06037. My position is Supervisor, Load and Settlement Planning and Operations, at Eversource Energy Service Company and in that position I provide load settlement services to the operating companies of Eversource Energy including Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or "the Company").

Q. Please describe your educational background and professional experience.

A. I have worked at Eversource for 24 years in Energy Efficiency and Load Settlement. I have a Bachelor of Science Degree in Mechanical Engineering from the University of Rhode Island and a master's degree in Power Systems Engineering from Worcester Polytechnic Institute.

Q. Have you previously testified before the Commission?

A. Yes I have. I provided information to the Commission on the benefit-cost methodology used for the 2018-2020 Statewide Energy Efficiency Plan in Docket No. DE 17-136.

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

A. My name is Karen M. Asbury. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842. I am the Director of Regulatory Services for Unitil Service Corp. which provides centralized management and administrative services to all Unitil Corporation's affiliates including Unitil Energy Systems, Inc.

Q. Have you previously testified before the Commission?

A. Yes. I have testified before this Commission and the Massachusetts Department of Public Utilities on behalf of Unitil and its affiliates.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with other Unitil witness as well as Eversource and Liberty witnesses. In that testimony, I summarize my educational and professional background.

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

A. My name is John J. Bonazoli. I am the Manager of the Distribution Engineering Department for Unitil Service Corp. which provides centralized management and administrative services to all Unitil Corporation's affiliates including Unitil Energy Systems, Inc.

Q. Have you previously testified before the Commission?

A. Yes. I have testified before the Commission and the Massachusetts Department of Public Utilities on behalf of Unitil and its affiliates.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with other Unitil witness as well as Eversource and Liberty witnesses. In that testimony, I summarize my educational and professional background.

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

A. My name is Jeffrey M. Pentz. I am the Supervisor, Energy Supply for Unitil Service Corp. which provides centralized management and administrative services to all Unitil Corporation's affiliates including Unitil Energy Systems, Inc.

Q Please describe your educational background and professional experience.

A. I received my Bachelor of Arts degree in Economics from the University of Massachusetts. Before joining Unitil, I worked as a Contracting and Transaction Analyst with Mint Energy, a retail electric supplier. My range of responsibilities included contract negotiation with brokers and customers, retail billing, and sales. Prior to Mint Energy, I worked as a data analyst for Energy Services Group. My responsibilities included supplier business transaction testing and integration with regulated utilities. I joined Unitil Service Corp. in February 2016. I have primary responsibilities in the areas of default service procurement, renewable energy credit procurement and renewable portfolio standard compliance, load settlement, market research and operations, and monitoring renewable energy policy.

Q. Have you previously testified before the Commission?

A. Yes. I have testified before the Commission and the Massachusetts Department of Public Utilities on behalf of Unitil and its affiliates.

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

A. My name is Dilip K. Kommineni. My business address is 9 Lowell Road, Salem, NH 03079 and I am employed as the Sr. Manager of Engineering by Liberty Utilities Service Corp. ("LUSC"), which provides services to Liberty Utilities (Granite State Electric) Corp. ("Liberty").

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with other Liberty witness as well as Eversource and Unitil witnesses. In that testimony, I summarize my educational and professional background.

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

A. My name is Laura Sasso. I am employed by LUSC as a Senior Manager, Billing, East Region, providing services to the Liberty affiliates in the East Region, including Liberty.

My office address is 15 Buttrick Road, Londonderry, New Hampshire. I have been with Liberty for 11 years and have been in the industry for 27 years.

Q. Have you previously testified before the Commission?

A. Yes, I filed testimony in Docket No. DE 23-063, the Joint Utilities' Petition for Waiver of Certain Provisions of the Puc 2200 Rules.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 11, 2023, I submitted direct, pre-filed joint testimony in this docket with other Liberty witness as well as Eversource and Unitil witnesses. In that testimony, I summarize my educational and professional background.

Q. Mr. Garcia, please state your name, business address, company position, and principal responsibilities in your current position.

A. My name is Robert Garcia. My business address is 15 Buttrick Road, Londonderry, New Hampshire. My title is Manager, Rates and Regulatory Affairs. As Manager of Rates and Regulatory Affairs, I am primarily responsible for rate administration and regulatory affairs for Liberty EnergyNorth and Liberty Utilities (Granite State Electric) Corp.

Q. Please describe your educational background and professional experience.

A. I have an Artium Baccalaureus (Bachelor of Arts) degree in Political Science and French from Wabash College (Crawfordsville, Indiana) and a Master of Public Administration degree from the School of Public and Environmental Affairs at Indiana University (Bloomington, Indiana) with concentrations in Policy (Quantitative) Analysis and International Affairs. I also obtained a Certificat De Langue Et Civilisation Française from the Université de Paris – Sorbonne (Paris, France) and, as part of my graduate studies, studied French and European government at the École Nationale D'Administration (Paris, France).

I was employed by ComEd from April 2001 to March 2023. I began my employment with ComEd in the Regulatory Department as a Regulatory Specialist and moved on to the positions of Senior Regulatory Specialist in 2004, Manager of Regulatory Strategies and Solutions in 2008, and Director of Regulatory Strategy and Services in 2013 before assuming my last position as Director or Regulatory Innovation & Initiatives in 2021.

Prior to joining ComEd, I worked for nearly nine years at the Illinois Commerce Commission, beginning in 1992 as an intern in what was then the Office of Policy and Planning and ending in 2001 as the senior policy advisor to a Commissioner. I initially joined the Commission Staff through the James H. Dunn Memorial Fellowship program, a one-year program sponsored by the Office of the Governor. Through this Fellowship, I also held short-term positions in the Bureau of the Budget and the Governor's Legislative Office.

Q. Have you previously testified before the New Hampshire Public Utilities Commission?

A. Yes, I have.

Q. What is the purpose of this joint rebuttal testimony?

A. The purpose of Eversource, Unitil, and Liberty's (the "Joint Utilities") rebuttal testimony is to address various proposals made by parties to this docket submitted in testimony filed on December 6, 2023.

Q. How is this rebuttal testimony organized?

A. Our rebuttal begins by endorsing certain parties' support of sustaining grandfathering for existing net metering customers. We then discuss various proposed adjustments to the current compensation levels and structure of net metering credits. This is followed by a discussion of the implications of Community Power Coalition of New Hampshire's ("CPCNH") proposal involving accounting for unregistered customer energy exports as a reduction to the Joint Utilities' competitive suppliers' wholesale load obligation. We briefly assess the Office of the Consumer Advocate's ("OCA") central recommendations, and our testimony concludes by presenting the Joint Utilities' proposal for interconnection application fees.

II. GRANDFATHERING

Q: Clean Energy New Hampshire ("CENH") proposes a 20-year term for grandfathering existing projects that are currently assigned to either of the two net metering tariffs, and the CPCNH likewise supports grandfathering. Do the Joint Utilities have a position on this issue?

A: The Joint Utilities appreciate the reasoning for grandfathering as proposed by CENH, which after clarifying discussions at docket technical sessions, we understand to mean a 20-year term from the time each project begins net metering, *not* when the project interconnects to the grid. If a net metering customer wishes to move to a newer tariff, they may do so, but they cannot return to their original tariff. The 20-year term as proposed by CENH provides stability to the distributed generation ("DG") industry and to the regulatory community. The Joint Utilities agree with this policy objective, but we note that it will be difficult to implement and enforce through a project-specific policy. Currently, the interconnection application process and Joint Utility billing systems do not have the functionality to track when a system comes online and start a 20-year clock. We support the concept of grandfathering but would recommend a standardized term that the Joint Utilities can implement without incurring incremental costs or complexity, which would strike the balance of allowing for the evolution of net metering compensation while ensuring market stability by "serv[ing] to preserve the value of the investments [net-metered customer-generators] have made in DG systems." (Order No. 26,047 at 12 (August 18, 2017)).

III. ADJUSTMENTS TO COMPENSATION

Q: CENH and CPCNH suggest altering current net metering compensation in various ways. Do you have any general impressions regarding such proposals or comments on specific proposals?

A: As a general matter we understand the desire to adjust compensation to preserve or expand the accessibility of clean energy options for New Hampshire customers. The

Joint Utilities are also interested in maximizing the choices our customers have to meet their energy needs. Our concern remains the same as it was articulated in our original testimony in this docket – that any upward adjustment to credit for excess generation risks shifting costs to non-net metered customers as larger credits and expanded participation would increase overall program costs borne by all customers. Assertions that the revenues and customers benefits produced by distributed generation ("DG") are commensurate with proposed credits remain, to various degrees, based on assumptions and estimates that are ultimately difficult to validate. A compensation structure that remains weighted toward values that can be most readily measured and quantified will continue to support customer choices while mitigating the risk of cost shifting. The Joint Utilities believe energy values can be readily quantified and validated based on wholesale market prices and meter data and, as such, customers should continue to be credited for excess generation based upon the prevailing default energy service rate.

Long-term reductions in distribution and transmission system investment and operating expenses associated with deployment of DG will depend on the location of each DG project and the performance of those assets over time. Many DG projects will not meaningfully reduce or avoid expenses to operate the electric power system and may in fact result in additional costs for system upgrades and operating requirements. The Joint Utilities believe the current net metering tariff appropriately limits the inclusion of transmission and distribution values in credit for surplus generation to only the smallest projects which, by virtue of their size, are more likely to provide an incremental impact on loaded circuits and be distributed throughout a utility's service territory. Expanding credit based on transmission and distribution rates, both in magnitude and the scope of eligible projects, risks crediting projects for value that they may be less likely to realize.

CENH's proposal to include a one-cent adder for west facing solar is technically possible to implement but unfortunately cumbersome to enforce. Compensation based on the direction panels are facing would require a process to confirm the direction, which in turn would require a site visit to verify and consequently could delay the application process for the customers with west-facing panels as well as other customers in the interconnection queue. The west-facing adder would also create some degree of new administrative and billing costs associated with tracking the direction of each customer's panels and establishing separate credits in the applicable systems and equipment. Conceptually, the criteria for "west-facing" would also need to be more clearly defined. For example, it is unclear how a home with fixed panels facing both south and west (within the 225 to 315 degrees azimuth range proposed by CENH) would be credited under this proposal. Depending on the type of solar installation (*e.g.*, pedestal), the policy purpose of the adder also could be circumvented to take advantage of the credit by pointing southwest (225 degrees azimuth) initially and moving the direction of the panel due south after any utility inspection. This adder also runs the same risk of slowing down the application process due to verification requirements.

CENH also proposes to increase surplus generation credit for large customers (projects over 100kW) to include up to 50 percent of the transmission kWh rate and 50 percent of the distribution kWh rate. The surplus generation for small projects up to 100kW is also proposed to increase by inclusion of 50 percent of the distribution kWh rate, up from 25 percent. The CENH proposal would likely support further growth of distributed generation in New Hampshire as more customers would be able to cost-effectively install renewable energy by virtue of receiving increased credit for their excess generation. However, implementation of the proposal would also likely increase the level and risk of costs being shifted to other customers.

CPCNH has proposed numerous changes to compensation including: reducing the energy supply portion of the credit to essentially that of the competitive supplier's bid price to supply default energy service (eliminating RPS compliance and line loss); making all DG-connected storage eligible for compensation including storage charged from the grid; addition of credit for "actual avoided transmission costs" – for those projects with interval meters, and individual bespoke credit based on meter data, and for projects without meters one blanket credit amount – for all large projects over (100kW); and adding compensation for avoided capacity costs.

Taking these recommendations in order, reducing the supply credit to eliminate the component associated with RPS costs and a designated line loss adjustment factor would be feasible and would lower the costs of utility net metering that might otherwise result by reducing overall supply credits paid out. This would also create two different supply rates for net metered customers: one applicable to supply and the other applicable to customer exports. The full supply rate would be billed on net usage, and a different, lower rate would be credited for net generation. The Joint Utilities would incur some implementation costs for billing systems to credit at a different rate. But our larger concern is that having two different supply rates on one bill would risk creating customer confusion and make it more difficult for net metered customers to understand their bill if multiple supply rates are used. The Joint Utilities recommend preserving the administrative and customer efficiencies associated with crediting customers at the same supply rate they are billed.

And to clarify a factual matter in response to the assertion in CPCNH's testimony that there is no basis to include RPS compliance costs in the net metering credit, it is true that the bulk of the difference between the full default service rate and what the supplier is paid is mainly the cost of RPS compliance, which is calculated on utility MWh sales. However, there is a credit adjustment percentage that is released by the DOE in February each year that reduces the RPS obligation each utility owes through a credit to Class I and Class II Renewable Energy Certificates ("RECs") based on the capacity of net metered facilities that are not certified to produce Class I or Class II RECs, pursuant to RSA 362-F:6, II-a and Puc 2503.04(d). The RECs that Eversource receives from facilities that are on Eversource's Group Host Program, for example, are not certified for use, which therefore contributes to the credit from the DOE and reduces the RPS expense.

CPCNH's testimony cites an RPS adder of $0.00834, but it does not include the corresponding DOE RPS adder credit of $0.00607 which nets to $0.00227. The netted amount should be the basis for CPCNH's hypothetical cost examples rather than the $0.00834. There is also a comment in CPCNH testimony on Page 25, row 21 that the RPS reconciliation credit is unusually large. That is because the referenced credit includes the adjustment made to the Class III REC obligation made in April after the reporting year has concluded. For added context and clarification, the DOE has the option to ratchet down the Class III REC obligation for Load Serving Entities each year. And though it is optional, the DOE (and previously PUC through PUC staff) have exercised that option every year since 2008 except 2017-2019, and every year that reduction is pronounced down from the required eight percent to usually two percent or less. Ultimately, removing the RPS added from the net metering credit would be a negligible change in compensation, but would add significant complexity to compensation administration and to customers understanding their bills.

Making DG-connected storage eligible for net metering credits raises some questions. As an initial matter, the net metering statutory provisions and Puc 900 rules allow only customers generating electricity using renewable energy sources to be eligible for net metering. RSA 362-A:1-a, II-b and Puc 902.05 define an "eligible customer generator" as "an electric 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." Batteries do not fit within this definition of "generator". Furthermore, there is concern about customers charging their batteries from the grid instead of using their solar. Puc 902.05 requires any discharge to the distribution system be from renewable energy. While customers participating in Liberty's battery pilot were allowed to charge from the grid and receive credits when paired with solar, the Commission made it clear that this was only permitted because Liberty, not the customer, discharged the battery per pilot study parameters, which was for the specific and narrow purpose of offsetting predicted system peaks. Order No. 26,784 at 5-6, Docket No. DE 17-189 (March 15, 2023). So the policy purpose behind credit afforded customers in the Liberty pilot is not analogous to simply making all battery storage eligible for net metering credits, particularly if there are no checks on customer charging and discharging behavior. Liberty's control over discharging the battery ensured the battery was only used for the pilot's policy purpose. In contrast, there is little the Joint Utilities can do to ensure customers are not going to charge batteries from the grid, discharge to the grid, and then receive credit for that discharge erodes the policy objectives of net metering. The Joint Utilities therefore recommend that this proposal not be adopted at this time, or not without substantial qualifications or limitations on eligibility and application.

Also pertaining to battery storage is the related proposal by CENH to provide a two-cent adder for battery storage paired with DG, which unfortunately suffers from the same infirmary of enforceability. Namely, there is no efficient way to police customers with solar and storage to ensure they are not charging the storage with grid power and then discharging the storage to the grid. Efforts to do so will again add costs associated with site visits and potentially disrupt the interconnection queue, in addition to any incremental billing and other tracking costs to implement the adder. Lastly, it is unclear whether a two-cent adder, even if limited to a battery charged by a resource that qualifies for net metering, would materially change the economics of a battery investment and induce battery adoption by net metering customers. Thus, while there is certainty that costs will be incurred by the Joint Utilities to implement such an adder, there is no certainty that it would achieve the policy objective of expanding storage resources in the State.

The Joint Utilities have both practical and policy concerns with the CPCNH proposal that customers be compensated for avoided Regional Network Service ("RNS") charges. Implementation of the CPCNH proposal would risk crediting customer-generators amounts that significantly exceed any potential benefits that might be ultimately realized for utility customers and would further increase costs through expansion of utility administrative requirements.[1]

As an initial practical matter, the CPCNH proposal would increase the costs incurred by the Joint Utilities to administer net metering tariffs by requiring monthly, individual calculations of transmission credit based on interval data for those customer-generators with interval meters. Such a process would be a significant departure from preferred bulk

[1] The Joint Utilities also note that the CPCNH proposal may implicate federal jurisdictional issues regarding wholesale reassignments or sales of transmission service and potential "cost-trapping" of charges assessed based on FERC-approved transmission rates, as described in their submissions in Docket No. DE 23-026. *See* Joint Utilities' Initial Brief at 14-20; Joint Utilities' Reply Brief at 17-22; both as filed in Docket No. DE 23-026.

billing processes that efficiently support service to a high volume of customers. The CPCNH proposal that additional load profiles be derived for non-interval metered customers would also expand utility responsibilities and require considerable data and analysis.

More importantly, the CPCNH proposal appears based on incomplete analysis that equates charges assessed to utilities as regional network customers and then as costs charged to New Hampshire customers through operation of ISO-NE transmission tariffs with the actual costs incurred to build, maintain and operate the electrical transmission system for New Hampshire customers. These values are not the same, and it is important that their differences be recognized in the design of any net metering credit structure. The RNS costs referenced in the CPCNH proposal are shared regional costs *allocated* to New Hampshire customers (through their utilities as network customers) on the basis of each New Hampshire utility's proportional share of New England's peak load each month. Apportioning the costs of the regional transmission system on the basis of peak load is an efficient and reasonable method for recovering costs fairly from all New England customers, but it does not provide a price signal for actual transmission cost avoidance that should be incorporated into New Hampshire's net metering tariff. The RNS charges that result from this allocation method represent the total *average cost* of the regional transmission system expressed in $/kW and reflecting the regulated cost of service of the transmission system. Wholesale energy and capacity prices, on the other hand, reflect the *marginal cost* of competitively bid generating resources required to satisfy regional energy and generating capacity requirements. Actual transmission system costs are also not exclusively correlated with regional peak load. A significant portion of transmission investment and operating expense is driven by asset condition and reliability requirements. Even when transmission investments are made to address increased load, those investments are planned to address loading periods that extend beyond a single peak hour, and which may vary from regional peak periods. As a result, a net metering tariff that fully credits net metering customers for transmission charges on the basis of coincident peak load would likely credit customers for costs of the regional transmission system that have already been incurred and are unlikely to be avoided through peak load reduction.

The Joint Utilities recommend that the Commission decline to expressly credit customer-generators for allocated transmission costs as proposed by CPCNH for the reasons outlined above, but potential transmission system benefits should still be considered in this proceeding. The VDER study appropriately sought to assess potential transmission value based on the best available information. The Commission can reasonably expect that distributed generation is likely to have some aggregate beneficial impact on transmission costs that offsets the costs of net metering credits, even if that value cannot be precisely quantified and is likely much less than the value CPCNH proposes be credited to customer-generators.

Finally, the Joint Utilities note, as we did in our original testimony, that the default service supplier bid price includes costs for capacity, so customers are already receiving capacity credit through the energy supply portion of the current net metering tariff. CPCNH also proposes changes to the calculation of capacity obligations for competitive and default service suppliers which are discussed in the following section.

IV. ACCOUNTING FOR EXPORTS TO THE GRID BY MODIFYING LOAD SETTLEMENT

Q: CPCNH recommends that utility default service customers' energy exports to the grid moving forward are accounted for as a reduction in the wholesale load obligation of the utilities' respective suppliers. What changes does this implicate and what would those changes entail?

A. To account for energy exports to the grid that are not registered with ISO-NE, the Joint Utilities would have to make fundamental changes to how we settle load with ISO-NE. Currently, load settlement is done uniformly throughout the ISO-NE territory, so if New Hampshire were to change its process, it would be anomalous in the region. Adjusting the load settlement process is a matter of significant complexity that would take substantial time and resources to implement, as outlined in Liberty and Eversource's joint response to CENH data request 3-002, included with this testimony as Attachment A, and with which Unitil concurs. As stated in that response, numerous factors contribute to the time and resources that would need to be dedicated even to exploring this change: the implications to the whole of the New Hampshire competitive supplier community will necessitate a working group to reach consensus on any changes; and the load settlement systems of the Joint Utilities are enterprise-wide systems not dedicated exclusively to New Hampshire. This unfortunately slows any changes, because changes to these systems must wait in a larger queue and are inherently complex because it will be a New Hampshire-only change to a uniform, multi-state process.

Even without having completed actual cost estimates, the Joint Utilities can state with confidence that the proposed change to load settlement would be a seven-figure investment that would easily take two years, likely more, to complete. CPCNH's proposal did not state from whom the costs of these changes would be recovered—we assume that it would be from all customers—and it is unclear which customers would ultimately see benefits from this change. The proposed change would provide a relatively small reduction to suppliers' wholesale load obligation, and only for those suppliers that have disproportionally high penetration of behind-the-meter generation. And the reduction does not represent pure savings. Any savings seen by one supplier would have to be offset by increases to remaining suppliers that have disproportionally lower penetration of behind-the-meter generation. Costs shift from one supplier to another because overall, total load obligations remain the same across the whole of each utility's meter domain; in other words, the same amount of dollars is due to ISO-NE, regardless of the change to load settlement methodology, meaning there are no net savings, just a different allocation of costs.

As an additional matter, suppliers that provide utility default service bid an all-in rate – there is nothing that would require them, or any other competitive supplier, to pass on any savings they may receive (and it is unclear how much savings, if any, there will be) to utility default service customers or any other customers, or aggregations, they serve. Furthermore, for the utility to offset net metering credit costs by building a requirement to pass along any potential savings from adjustments to load settlement into default service RFPs would likely have a detrimental effect on the number and competitiveness of bids received for those RFPs, due to the likely reluctance of suppliers wanting to agree to this without knowing what the implications would be. So ultimately, for multiple reasons, the actualization of tangible benefits to customers, particularly once accounting for the costs to implement, is speculative.

Of significant concern is that the recommendation to modify the load settlement process entails an extensive effort with many moving pieces and ripple effects for many entities, most of which are not parties to this docket. If the Joint Utilities were to modify how they settle load for default service energy suppliers, load settlement would have to be modified across the board for all suppliers in New Hampshire, for several reasons. First, load settlement is administered pursuant to the Joint Utilities' tariffs, which must be applied uniformly; and to apply different methods for load settlement ad hoc would be fundamentally unfair to suppliers who do business in the state. And as a practical matter, a single method for settling load is the only feasible way to execute load settlement. So these changes are really implicating the New Hampshire supplier community as a whole, and as such the supplier community should have an opportunity to weigh in on a topic that would directly and significantly impact their business.

When combining the repercussions discussed above to the considerable costs attendant to the proposed modification to the load settlement process, costs that have a high level of uncertainty regarding commensurate benefits, we do not support adopting this recommendation to apply to utility default service energy suppliers. The Joint Utilities refrain from commenting on the merits of applying these changes to enable community power aggregation ("CPA") net metering, as that is a different question with distinct issues that are outside the scope of this docket and thus must be addressed in a dedicated proceeding of its own; and in any event, adjusting the load settlement process should be addressed in a separate proceeding to provide notice of the issue to all appropriate and potentially affected parties. Relatedly, we note that neither the rule cited to in CPCNH's testimony, Puc 2205.15, nor the statutory provision of RSA 362-A:9, II, contain any compliance obligation of the Joint Utilities as they are enabling provisions allowing CPAs to offer net metering credit programs. Therefore, there are no compliance implications in this docket.

However, before concluding the discussion of accounting for unregistered generation of net metered customers, we would like to mention the merit in a possible alternative to changing the load settlement process. Developing load profiles for net metered customers has the potential to achieve the same policy objective more efficiently and with less disruption. These profiles currently do not exist, because there is no rate class for net metered customers. However, if these profiles were created and used to calculate suppliers' load, it would result in a wholesale load obligation for each supplier that more accurately accounts for the load reduction resulting from behind-the-meter generation of net metered customer-generators served by each supplier than the existing load profiles currently provide.

If the Commission were to see merit in this approach, with the necessary Commission authorization for the Joint Utilities to acquire and install interval meters with a sufficient number of each utility's net metered customers (for those that do not have interval meters already), gather and validate the utility-specific data, and develop the profiles, this is an approach which the Joint Utilities already have the expertise to execute. However, we must provide the caveat that each utility would have to acquire interval meters capable of netting that are also compatible with existing utility billing and meter systems. Though this approach would take incremental resources and a couple of years to execute—hence the need for Commission authorization—it is in our view a more equitable solution as it is less cost, impacts fewer people that would not benefit from the changes, and would not insert risk into enterprise systems of the Joint Utilities.

V. HOURLY NETTING AND COMPREHENSIVE NET METERING STUDY, ANALYSIS AND PROPOSAL

Q. The Office of the Consumer Advocate has proposed that utilities provide hourly netting as opposed to monthly netting. Can you explain the logistical implications of this shift and the practical impacts of its application?

A. Each of the Joint Utilities has different capabilities when it comes to both metering and billing. But at its core, it seems that shifting to hourly netting from monthly netting would incur substantial complexity in administration, as reflected in each of Eversource's and Liberty's responses to CENH's data request 3-001[2], included as Attachment B to this testimony, and the corresponding costs of added administrative complexity. And while there is validity in Mr. Woolf's testimony that moving to hourly netting has the potential to result in more accurate compensation for net metering customers, the benefit seemingly would be limited to net metering that incorporated time of use pricing, which is a discussion that OCA itself has deferred to years into the future. But, to make such a change now, absent such a rate structure, makes it unclear what, if any, associated benefits there would be to customers, putting aside the question of whether such benefits would be proportionate to the costs required to implement the change and administer accordingly, So while we see the potential merit in the policy objective of Mr. Woolf's proposal, ultimately we think it is not likely to yield a net benefit to the existing net metering compensation structure and process.

[2] At the time of this filing, Unitil is still finalizing this information.

Q. Can you also comment on Mr. Woolf's proposal that the Joint Utilities execute an analysis of possible changes to the current net metering tariff to be completed by December 2025, and the recommendation that the Commission review net metering compensation and alternatives to it every three years?

A. Yes. The Joint Utilities are capable of conducting such an analysis, but we question whether the Joint Utilities, rather than the New Hampshire Department of Energy ("DOE"), as the State's energy policy agency, are the appropriate entities to conduct such an analysis. Ultimately, the Joint Utilities are program administrators, and as such relatively neutral as to the compensation level to net metering customers. We can certainly provide input regarding practical and policy implications of various aspects of such an analysis, the analysis itself – what should be examined and what, if any, changes should be recommended – is a matter of State policy and as such seems to rightfully belong with the DOE. The Joint Utilities would certainly be willing to lend support and expertise where needed and useful.

We would caution against a three-year Commission review of alternatives to existing net metering. Doing so would not only significantly increase the overall administrative efforts of net metering regulation and administration, it would also inject an element of market uncertainty that could have an unintended detrimental effect on the market.

VI. APPLICATION FEE PROPOSAL

Q. The DOE in its testimony noted that further detail and a sufficiently granular proposal was needed to consider implementing interconnection application fees as a part of this docket. Do you have a proposal for consideration of the parties?

A. Yes, we do. The DOE's chief concern was that the Joint Utilities demonstrate that the fees proposed were going to cover only those costs that are incremental and not covered by existing base distribution rates, to avoid "double recovery" of application processing costs; they also wanted a more clearly articulated and definitive proposal, and a description of the benefits that customers will yield in return for these fees. We have addressed both with the proposal included with this testimony as Attachment C, which proposes graduated application fees that begin at $200 for projects less than 30 kW, increases to $500 for projects up to 100 kW and $1,000 for all other applications. The total amount collected through proposed fees will depend on the volume of applications submitted to each utility, but is expected to be generally consistent with the amount of administrative cost each Company anticipates to incur to support the interconnection and enrollment process for customer-generators. These costs that are expected to be funded through fees from customer-generators are presented and described in Attachment C. The administrative costs presented in Attachment C include costs incurred during the test year applied in each company's most recent base rate proceeding that could be reasonably identified to have been incurred directly in support of the interconnection and enrollment process for customer-generators. It is not possible for the utilities to comprehensively isolate all costs historically incurred to support customer-generators since a number of activities are performed in the normal course of business by staff with other responsibilities. For example, the billing department tasks outlined in the Joint Utilities initial testimony are more involved for customer-generators, but have not been managed or tracked separately from other billing operations in a way that would enable the utilities to readily isolate the billing costs that have resulted from growth in the volume of customer-generators.

The Joint Utility fee proposal includes several provisions that will ensure that the revenues collected by each utility through both fees and base distribution rates are commensurate with the administrative costs incurred to support customer-generators, and that double-recovery of costs does not occur. The Joint Utilities propose to track and report, on an annual basis, (1) the total amount of application fees collected from customer-generators, and (2) the total administrative cost incurred to directly support the interconnection and enrollment of customer-generators. The total amount of application fees will be added to the annual amount of administrative costs incurred during the test year applied in each company's most recent base rate proceeding to determine the revenue each utility received in support of the interconnection and enrollment of customer-generators. If this combined revenue exceeds reported administrative costs for any annual period, the excess revenue shall be credited to all customers through each utilities Stranded Cost Recovery Charge. [3] At this time the Joint Utilities do not propose

[3] At this time, Unitil intends to credit 100% of application fee revenues to its SCRC deeming its current costs as not incremental. To the extent Unitil hires new employees or temporary help in the future to directly support interconnection and tariff enrollment of customer-generators, these costs would be identified in its annual report and netted from the application fee revenue. In addition, should Unitil incur other incremental costs including but not

that any administrative costs in excess of revenue would be eligible for recovery through the SCRC. Utility costs eligible for inclusion in amounts funded by application fees through this proposed mechanism shall also be limited to operation and maintenance costs that can be demonstrated to have been incurred to directly support interconnection and tariff enrollment of customer-generators. Lastly, reported administrative costs shall be subject to review and approval by the Commission in each utility's annual SCRC proceeding.

Q. What are the anticipated benefits from implementation of the proposed application fee structure?

A. The Joint Utilities believe there are several benefits to implementing the fee proposal. As an initial matter, the proposal will result in a more equitable allocation of utility costs among customer-generators and all other customers in a uniform statewide manner. Services to customer-generators are presently funded through distribution rates paid by all customers. Operation of the fee proposal will ensure that customer-generators fund, through fees, expansion of utility resources that support their interconnection and enrollment.

The Joint Utilities also expect that the collection of application fees will expand opportunities to improve service to customer-generators. Application fees will automatically support revenue that is directly correlated to the volume of customer-

limited to system or software costs, such as licensing and maintenance fees, those incremental costs would also be applied as an offset to application fee revenues.

generator applications and enable the Joint Utilities to responsively expand resources to match customer demand. A dedicated revenue source enables more responsive management of resources than what regulatory and enterprise budgeting processes are likely to support.

With scalable resources, the application process and processing times are expected to improve or be consistently sustained at a higher level than they otherwise would. While there are too many variables, both on the utility and customer/developer sides of the application process, to offer guarantees or a set number of days for process completion the Joint Utilities are confident that customers will see benefits of these fees. The Joint Utilities propose to provide quarterly reports that includes application processing metrics and narrative descriptions of how each Utility is managing interconnection processes to streamline and expedite the experience of customer-generators. Proposed reports will be sufficiently detailed to assess whether the fees are having the intended effect and support opportunities for the DOE, Joint Utilities and stakeholders to meet and discuss process improvements or adjustments to the fees.

VII. CONCLUSION

Q. Are there any overarching considerations you would like to note?

A. Yes, overall, the Joint Utilities see the merit in fostering the continued growth of DG and the DG market in New Hampshire, as increased implementation of DG advances multiple state policy objectives. The range of proposals contained in the testimony submitted by certain parties to this docket were thoughtfully developed and all aim to fulfill various policy objectives. As administrators of the State's net metering program and tariff, the Joint Utilities have tried to provide additional information and considerations pertaining to some of the recommendations made by those parties so that all parties to the docket and the Commission can proceed with more complete information in reaching conclusions regarding possible changes to the net metering tariff and net metering compensation and the policy objectives represented by New Hampshire net metering. Generally, we are also supportive of any entity supplying energy to customers, whether a CPA or competitive supplier, be able to offer net metering credits, if it can be accomplished in a way that is equitable for all customers and is not disruptive to utility operations. Regarding the current net metering tariff, we still believe that maintaining the status quo of net metering customer compensation levels and process is in the public interest, but also see room for implementing changes along the lines of some of those suggested to foster policy advancement, again taking into account customer equity and feasibility of administration.

Q. Does this conclude your testimony?

A, Yes, it does.

Request from: Clean Energy NH

Witness: Swift, Joseph R, Bennett, Colleen E

Request:

In the direct testimony of Clifton Below on behalf of the Community Power Coalition of New Hampshire (CPCNH), there is a section regarding "Accounting for Exports from the Grid," in which CPCNH discusses how Eversource could "change the load settlement process for all suppliers, including CEPS, and default service suppliers." Cf. page 15 of 32. In this section, there is reference to a "residual" calculation to balance between wholesale utility meter reads and retail meter reads, this discussion occurs or use settlement for each hour as an illustration.

a. Can the Joint utilities explain how this settlement process and residual calculation referenced by CPCNH works? If the explanation is different by utility, please specify.

b. If there is a socialized residual from these calculations, can the Joint Utilities or each utility explain how a residual crediting mechanism (+ or -) is applied? How frequency (*e.g*., hourly, daily, monthly, annually)?

c. Can the Joint Utilities or each utility explain if DER customers see bill impacts that are positive or negative (from the customers perspective) as a result this residual crediting mechanism?

d. Can the Joint Utilities or each utility explain if all ratepayers see bill impacts that are positive or negative (from the customers perspective) as a result of this residual crediting mechanism?

e. Is it possible to resolve the bill impact benefit or negative impacts that this residual crediting mechanism creates just for NEM customers in this docket? Or would changes to the mechanism necessarily have to be holistic and therefor incorporate more stakeholders?

f. CENH understands the CPCNH proposal for a residual crediting mechanism (+ or -) to be proposed for >100 kW NEM customer-generators.

i. Can the Joint Utilities confirm if they understand the CPCNH proposal similarly, and offer any analysis or thoughts, assuming the CPCNH residual crediting mechanism (+ or -) is not applied directly to <100 kW NEM customer-generators' accounts, on whether this proposal would impact <100 kW NEM customer-generators?

g. Do the Joint Utilities or each utility have any estimates for costs to accomplish and implement a residual crediting mechanism as proposed by CPCNH?

   i. If the Joint Utilities or each utility do not have cost estimates, can the joint utilities opine on whether the costs would be six figure or seven figure magnitude to implement?

Response:

a. The residual includes the difference between the total customer consumption including line losses at the distribution meter and wholesale loads measured by the utility and ISO-NE at the transmission level, both on an hourly basis. The residual is a combination of several items. The first component is the delta between the statistically-developed rate class load profile estimates that approximate usage for customers within that class and the eventual calibration with actual customer hourly consumption. The second addition is the differences in estimated versus actual line losses; then unregistered distributed generation—which is not part of the wholesale market and therefore not captured or quantified as part of wholesale settlement—is added to the residual. There are additional ancillary differences that arise from meter precision and other variables, but these are de minimus factors. Currently, the residual is first compiled and then distributed to each supplier according to each supplier's percentage of the total utility profiled load. The CPCNH proposed modification to the load settlement process would change the order in which these calculations are done, by applying and deducting excess generation from unregistered customer-generators to the customers' suppliers' load obligation before the compilation of the residual. The residual would then still be compiled using all remaining factors and distributed to suppliers in the same manner. The only change is that excess generation of each customer-generator gets applied to the corresponding supplier first. This turns what is currently a one-step process into a three-step process: calculate the excess generation that is associated with each supplier; calculate supplier load obligation by subtracting excess generation, then apply the residual to that new resulting number for each supplier. The proposed modified calculation would shift some costs between load assets due to the assignment of customer exports to their suppliers, but overall ISO-NE Joint Utility hourly settlement totals would not and cannot change, and there is still a residual that gets allocated among the suppliers after the deduction of the exported unregistered energy from customer generators.

b. The residual crediting mechanism (+ or -) is applied hourly to supplier loads based on their share of profiled loads during each hour. This would not change if the proposed calculation method were applied, as the residual will remain.

c. The Joint Utilities do not have insight into the analytics that suppliers use to determine retail prices. Therefore, Eversource cannot determine what, if any, impact the residual calculation has on the retail rates that suppliers charge customers. This would be entirely up to the discretion of the suppliers to adjust what they charge to retail customers.

d. Based on 2022 PSNH settlements, the residual resulted in an average adjustment of -2.77 percent (credit) to load assets. As explained in (a) above, the -2.77 percent consists of several factors including estimated versus actual profiles and line loss assumptions, as well as unregistered generation. Eversource does not have insight into the analytics that suppliers use to determine retail prices and how the -2.77 percent adjustment to hourly loads are reflected in retail energy rates that suppliers charge. However, the residual will still exist, it will just be modified in the manner described in part a.

   Liberty does not have the residual average adjustment available that Eversource has provided, but agrees that we do not have insight into the analytics suppliers use to determine retail prices and that the residual continues to exist.

e. Deciding whether to adjust suppliers wholesale load obligation would necessarily impact any supplier that does business in New Hampshire, most if not all of which are not parties to this docket. Those entities that would be affected by this proposal should have an opportunity to intervene and participate fully in a docket. There could also be ISO-NE implications that accompany this proposal so the full extent of the entities affected isn't definitely known at this time.

   Changes to existing settlement calculations, however minor, need to be transparent and should be vetted through a working group consisting of energy suppliers, the ISO New England Meter Reader Working Group, and possibly other New England state regulatory bodies. Any proposed revisions should be thoroughly studied and deemed appropriate prior to implementing. The CPCNH proposal, while technically feasible, is more complex and would require hourly quantification of all excess generation, and therefore, Eversource would need hourly metering and data collection systems for net metered customers or would need to develop statistically valid profiles for these customers. Beyond that, the proposal would require significant and costly modifications to the settlement system to allow for direct treatment of excess generation. Any modifications to settlement calculations should be transparent and vetted through the Working Group and stakeholder process just mentioned.

f. Eversource (the Joint Utilities) understands the mechanics of the proposal. By not applying all attributable exports to suppliers, the change to the calculation of the residual is only a partial one, essentially leaving an element of the existing methodology in place. The proposed revisions would result in some minor cost shifting, because load settlement is a zero-sum game – ISO-NE has to receive the same payment no matter how it is distributed among suppliers. The proposed calculation would favor (give some credit to) load assets with higher amounts of excess generation; and would give less or no credit to load assets with lower amounts of excess generation, compared to current methodology which distributes all excess generation credit uniformly according to a supplier's share of the total utility profiled load. Overall, it would result in no savings for Joint Utility wholesale customers (suppliers) in aggregate, because the same amount is paid to ISO-NE, once the residual has been distributed among the suppliers.

g. There are no estimates of the costs to accomplish and implement the modified crediting mechanism and change to load settlement as proposed by CPCNH, but the Joint Utilities can safely say that the costs to implement would be substantial and would likely enter seven figures when considering necessary metering upgrades and settlement system upgrades. Liberty and Eversource use the same settlement calculations including the residual allocation methodology throughout their service territories, consistent with all of ISO-NE and also uses one load settlement system across all service territories in its enterprise, making any changes to it a complex and time-consuming undertaking. [1] It is unclear from which customers the proposal intends the costs of these changes be collected.

[1] Changes to the settlement process in New Hampshire could impact calculation processes used for settlement in other ISO-NE states outside of New Hampshire, which could cause confusion and operational complications for suppliers who do business across the Joint Utilities' territories. It is also unclear what the position of the FERC-regulated ISO-NE would be toward New Hampshire settling load differently than the rest of the ISO-NE states.

Date Request Received: December 19, 2023
Data Request No. CENH 3-001

Request from: Clean Energy NH

Witness: Davis, Edward A.; Coskren, Dawn

Request:

In the direct testimony of Tim Woolf and Eric Borden of Synapse on behalf of the New Hampshire Office of Consumer Advocate (OCA), Mr. Woolf and Mr. Borden advocate for an hourly netting regime for NEM in New Hampshire and a proceeding to figure that regime out. Cf. Woolf and Borden testimony at p. 32.

a. Is hourly netting feasible for each of the Joint Utilities given current utility systems? Can hourly netting be implemented at a nominal or negligible cost? Please suggest a rough cutoff for how the utility might define nominal or negligible cost.

b. If hourly netting is not immediately feasible at nominal or negligible cost(s), please explain the utility hardware, software, firmware systems and processes that would require update or replacement to accomplish hourly netting for the Joint Utilities or each utility including but not limited to:
   i. Customer meters
   ii. Meter communications systems and relays
   iii. Customer information storage database(s)
   iv. Customer information data management and access system(s)
   v. Customer data information sharing system(s) through either
      1. Customer service representatives, or
      2. Directly through customer data portals,
      3. Or otherwise (please explain)
   vi. Load settlement system(s)
   vii. Billing system(s)
   viii. Other systems or hardware that would require updates or upgrades?
   ix. If any of these systems or functions would require manual calculation and

dedication of personnel beyond current assignments and functions to accomplish hourly netting, please explain.

c. Does each utility have any estimated costs for performing the upgrades and updates address in question 1b?

    i. If no specific estimated costs, do the Joint Utilities or each utility have any order of magnitude cost estimates for individual items explained in the answer to 1b (e.g., is each a six figure or seven figure upgrade or update)?

        1. Are there any estimate for accomplished those functions in 1b manually for NEM ratepayers in NH annual or over a multi-year period?

    ii. Would the utility in its judgement plan any of these update(s) for purposes of the NEM tariff compliance?

d. Does the utility have any information or data on the customer or system benefits of implementing the hourly netting proposal?

Response:

a.

The answer depends on what Mr. Woolf and Mr. Borden are seeking with hourly netting. If they are only seeking to apply what Eversource does with Large Commercial customers, which is instantaneous netting and involves using net consumed energy from one billing meter channel and net excess generation from another billing meter channel and apply that process to small commercial and residential customer generators, Eversource would not require interval meters. This scenario would be possible to implement with existing meters and supporting systems, and so Eversource could implement this version of hourly netting comparable to what Eversource does for Large Commercial customers through modifications to its C2 billing system.

These changes would incur more than nominal costs, as changes to the C2 system are typically complex undertakings. Without having done an actual cost estimate, Eversource can provide an initial assumption that these costs, at an order of magnitude level, would be about six figures, likely mid to high six figures. However, regardless the approach to hourly netting, it is almost certain that some degree of manual intervention would have to be involved and would create ongoing, incremental costs additional to the implementation costs, which have not been estimated at this time. The degree of manual intervention would vary depending on the specifics of the approach to hourly netting (i.e. the need for interval meters, or not), but examples of the types of manual intervention that could be required are: manually tracking account data, creating custom reports to pull the relevant data and then regularly running those reports every billing cycle, and creating and using calculation sheets to manually calculate the net metering credits, if the crediting calculation function cannot be automated. These are examples of manual intervention efforts that are currently applied to the "instantaneous netting" that is done for the small group of Large Power Billing customer generators.

This scenario also assumes that the current compensation structure stays the same, because changes to the compensation structure would necessitate additional modifications to the Eversource billing systems. Any of these changes could not happen overnight and could take a minimum of several months and could take a year or more.

If, however, Messrs. Woolf and Borden are suggesting using hourly data to conduct hourly netting, hourly data would require interval meters, such as AMI technology. For Eversource, hourly net metering is currently not feasible with existing meter or billing systems, or existing AMR meters, which is what approximately 98% of Eversource customers have. Implementing hourly netting in this fashion cannot be done at a nominal or negligible cost, assuming the definition of nominal or negligible to be $100,000 or less. Given the number of systems implicated, and the need for interval meter installation, the company can state with relative confidence that implementing hourly netting using interval data would be a nine-figure investment.

b.

The systems that would likely need to be modified or replaced wholesale would be the following listed below, in italics. This is the company's best assumption at this time, without a granular proposal to assess.

i. Customer meters – *yes, customers would need AMI/interval meters installed*

ii. Meter communications systems and relays – *for interval time of use cellular meters, existing systems could be used, the meters themselves are just very expensive (approx. $650 per meter, plus installation and setup – these also have a one-year lead time to obtain). However, to implement AMI, new meter systems able to interface with the new meters would need to be installed, as well as all accompanying software and reading equipment necessary for communication between meters and the corresponding systems. This would also likely entail wholesale replacement of all billing systems.*

iii. Customer information storage database(s) – *without a more granular proposal it is unclear what would be needed to satisfy the data storage needs, but it would likely require either considerable changes to existing billing and meter systems to hold exponentially greater interval meter data, or new systems altogether. One factor that would influence this would be how many meters this would apply to for instance.*

iv. Customer information data management and access system(s) – *the answer to this would likely parallel or depend upon the answer to iii. Above.*

v. Customer data information sharing system(s) through either – *this element would depend on the proposal as well – it is not sufficiently clear what kind of customer contact, education, and service would be expected with hourly netting.*

1. Customer service representatives, or
2. Directly through customer data portals,
3. Or otherwise (please explain)

c.

i. If the above were the scope of the changes required to implement hourly metering, which is Eversource's best assumption at this time, this would like be a nine-figure initial investment for Eversource, with additional incremental ongoing operation and maintenance costs. However, if the testimony is suggesting the first example discussed in this response (mimicking instantaneous netting like is done for Large Commercial Eversource customers), then the costs would likely be more in the range of mid to high six figures.

1. As previously discussed, the first option (instantaneous netting) could be implemented with a degree of manual intervention, using existing systems. If hourly netting would require interval data, the new systems described above would be a necessary condition precedent.

ii. If the question is asking if Eversource would recommend moving to hourly netting as a means of updating the current net metering tariff, in either scenario of hourly netting discussed above, this functionality needs further examination and analysis of a more granular and detailed proposal before the full scope of the needed investments can be determined. Eversource does not believe that compliance with the current NEM tariff requires hourly netting, and believes it is premature to attempt this update without knowing exactly what is being proposed to be implemented and a plan for execution of that implementation is fleshed out.

d.

Eversource is uncertain of any net customer or system benefits resulting from switching to hourly netting once accounting for the upfront investments and ongoing, incremental costs required to implement such an update. It is possible that moving to hourly netting would not result in commensurate system or customer benefits, as it is unknown if the costs to implement hourly netting would outweigh any possible benefits created by more accurate net meter crediting compensation as a result of hourly netting, as is posited in testimony by Messrs. Woolf and Borden.

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

Clean Energy New Hampshire Data Requests - Set 3

Date Request Received: 12/19/23	Date of Response: 1/11/24
Request No: CENH 3-1	Respondent: Robert Garcia

REQUEST:

In the direct testimony of Tim Woolf and Eric Borden of Synapse on behalf of the New Hampshire Office of Consumer Advocate (OCA), Mr. Woolf and Mr. Borden advocate for an hourly netting regime for NEM in New Hampshire and a proceeding to figure that regime out. Cf. Woolf and Borden testimony at p. 32.

a. Is hourly netting feasible for each of the Joint Utilities given current utility systems? Can hourly netting be implemented at a nominal or negligible cost? Please suggest a rough cutoff for how the utility might define nominal or negligible cost.
b. If hourly netting is not immediately feasible at nominal or negligible cost(s), please explain the utility hardware, software, firmware systems and processes that would require update or replacement to accomplish hourly netting for the Joint Utilities or each utility including but not limited to:
    i. Customer meters
    ii. Meter communications systems and relays
    iii. Customer information storage database(s)
    iv. Customer information data management and access system(s)
    v. Customer data information sharing system(s) through either
        1. Customer service representatives, or
        2. Directly through customer data portals,
        3. Or otherwise (please explain)
    vi. Load settlement system(s)
    vii. Billing system(s)
    viii. Other systems or hardware that would require updates or upgrades?
    ix. If any of these systems or functions would require manual calculation and dedication of personnel beyond current assignments and functions to accomplish hourly netting, please explain.
c. Does each utility have any estimated costs for performing the upgrades and updates address in question 1b?
    1. If no specific estimated costs, do the Joint Utilities or each utility

have any order of magnitude cost estimates for individual items explained in the answer to 1b (e.g., is each a six figure or seven figure upgrade or update)?

i. Are there any estimate for accomplished those functions in 1b manually for NEM ratepayers in NH annual or over a multi-year period?

ii. Would the utility in its judgement plan any of these update(s) for purposes of the NEM tariff compliance?

d. Does the utility have any information or data on the customer or system benefits of implementing the hourly netting proposal?

<u>RESPONSE</u>:

a. Liberty's current metering cannot accomplish this. AMR meters do not collect data hourly. Liberty will need to install AMI metering for all customers to accomplish this feat. As for the billing system, assuming Liberty has AMI, the current billing system would need upgrades to integrate hourly interval netting. The costs and timeline to implement are not known at this time.

b. Please see the information provided below:

    i. Requires AMI – see response to part a.
    ii. Requires AMI and all backend software/hardware necessary to have meter communications and relays function accordingly
    iii. Requires AMI and all backend software/hardware necessary
    iv. Requires AMI and all backend software/hardware necessary
    v. This question is unclear as to what the parties are referring, nonetheless any information to be shared about hourly netting will require AMI as provided in part a.
    vi. See Joint Utilities responses to CENH 3-002 and CENH 3-003
    vii. Requires AMI – see response to part a.
    viii. Requires AMI – see response to all sections above
    ix. Requires AMI – see response to part a.

c. Liberty does not have costs at this time, though estimated costs for AMI implementation is provided in Docket No. DE 23-039.

d. Liberty does not have benefits at this time, though assumed benefits for AMI implementation is provided in Docket No. DE 23-039.

New Hampshire Customer-Generator Application Fee Proposal

The Joint Utilities propose to collect standard, graduated fees for all applications to interconnect by customer-generators. Fees collected by the Utilities will offset the general administrative costs incurred for personnel, systems and services that support the review and processing of applications to interconnect and administration of the net metering credit program.

1. **Fee Amounts:** The following proposed fees by project size are consistent with interconnection application fees assessed by electric distribution companies in other New England states and represent a very small percentage of anticipated overall project costs:

Generating Capacity (AC)	Application Fee
Up to 30 kW	$200
Greater than 30 kW, up to 100 kW	$500
Greater than 100 kW	$1,000

2. **Eligible Administrative Expenses:** Revenues collected from application fees will offset utility costs for staff, services and systems that are required to efficiently process customer-generator applications to interconnect consistent with Puc 900 and other applicable rules and tariffs for electric service. This processing of applications begins with the initial acceptance and review of interconnection applications and extends through issuance of permission to operate and billing account creation for a customer-generator. Utility resources are required to review application materials, communicate with customer-generators and renewable energy installers, track progress through applicable process milestones and ensure required information is recorded into utility systems. General administrative resources that utilities propose to fund through application fees include the following categories:

Category	Description
Labor	Utility employees or contracted staff in positions that directly support the processing of applications to interconnect by customer-generators. Includes staff assigned to departments dedicated to support of customer-generators and proportional costs of staff assigned to other departments with documented responsibilities in support of customer-generator interconnection. Includes labor costs inclusive of benefit loaders and employee expenses
Outside Services	Vendors that provide specialized services and/or technology solutions to support utility interconnection processes. Includes consulting services and license fees
Information Systems	Information technology solutions that support utility interconnection processes. Amounts expected to be included as outside service costs

The Joint Utilities have already incurred costs within some or all of the above categories. These amounts, including those incurred in the test year applied in each company's most recent base rate proceeding, are summarized in appendices to this proposal. These costs have or are expected to grow as the Joint Utilities expand resources to efficiently process an increasing number of applications to interconnect by customer-generators.

3. **Excluded Costs:** Proposed application fees will not offset costs associated with evaluation of individual projects through Pre-Application Reviews conducted pursuant to Puc 904.01, Studies and Analysis conducted pursuant to Puc 905.06, or Upgrades or Improvements to the Electric Distribution System identified pursuant to Puc 905.07. Since there is no overlap among these various fees, the aforementioned costs will continue to be funded by individual Customer-Generators through Pre-Application fees, Supplemental Review Fees and payments for Upgrades or Improvements. Customer-Generators shall not be assessed any Supplemental Review Fees to cover general administrative costs funded through application fees.

4. **Annual Reconciliation:** The Joint Utilities propose that an annual report and reconciliation of application fees take place in each Company's annual Stranded Cost Recovery Charge ("SCRC") filing. Each utility shall provide a comparison of application fee revenues collected to actual general administrative costs incurred to support the review and processing of applications to interconnect. Revenues collected to support general administrative costs shall include total application fees collected in the prior year as well as costs for review and processing of applications to interconnect included in operations and maintenance expense of the test year applied in each Company's most recent base rate proceeding. Revenues and general administrative costs shall not include amounts associated with individual projects for Pre-Application, Supplemental Review or Upgrades and Improvements.

   If revenues collected to support general administrative costs exceed actual general administrative costs in any year, the excess amount shall be credited to customers through the SCRC. The Utilities shall not include any deficiency in revenues from the combination of base rate revenues and application fees to support general administrative costs in amounts for recovery through the SCRC without prior authorization by the Commission. However, the Commission may approve changes to fee amounts in any Companies SCRC filing to achieve better alignment of revenues and administrative expenses in future years.

   Each Company shall be responsible for reasonably demonstrating, within each annual SCRC filing, that administrative costs were incurred directly in support of the interconnection processes for customer-generators.

5. **Performance Reporting:** The Joint Utilities propose to provide quarterly reports that includes application processing metrics and narrative descriptions of how each Utility is managing interconnection processes to streamline and expedite the experience of customer-generators. Proposed reports will be sufficiently detailed to assess whether the fees are

having the intended effect and support opportunities for the DOE, Joint Utilities and stakeholders to meet and discuss process improvements or adjustments to the fees.

Interconnection Application Fee Proposal

Eversource Illustrative Calculations

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Line	Project Size		Application Volume	Potential Fee	Revenue	Description
1	< 30 kW		4,115	$ 200	$ 823,000	
2	30 - 100 kW		22	$ 500	$ 11,000	
3	> 100 kW		20	$ 1,000	$ 20,000	
4						
5	Total Revenue					
6	Application fees				$ 854,000	Sum of Line 1 to Line 3
7	Distribution rates				$ 353,027	Page 2, Line 5
8		Total			$ 1,207,027	Line 6 + Line 7
9						
10	Annual interconnection admin costs				$ 1,155,652	
11						
12	Amount to be Credited/(Surcharged) to Customers through SCRC[1]				$ 51,376	Line 8 - Line 10

[1] *Subject to PUC approval*

Interconnection Application Fee Proposal
Eversource *Administrative Costs*

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Line		2018	2023	Projected
1	Employee Labor	351,161	563,892	863,892
2	Employee Expenses	1,866	1,523	1,500
3	Contractor Labor	-	70,130	140,259
4	Outside Services	-	-	150,000
5	Total	353,027	635,544	1,155,652

Interconnection Application Fee Proposal
Liberty Illustrative Calculations

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Line	Project Size	2023 Application Volume	Potential Fee	Revenue	Description
1	< 30 kW	613	$ 200	$ 122,600	
2	30 - 100 kW	5	$ 500	$ 2,500	
3	> 100 kW	10	$ 1,000	$ 10,000	
4					
5	Total Revenue				
6	Application fees			$ 135,100	Sum of Line 1 to Line 3
7	Distribution rates[1]			$ 118,005	
8	Total			$ 253,105	Line 6 + Line 7
9					
10	Annual interconnection admin costs[2]			$ 236,010	
11					
12	Amount to be Credited/(Surcharged) to Customers through SCRC			$ 17,095	Line 8 - Line 10

[1] *One fully loaded FTE which includes the burdens*
[2] *Based on the uptick of the applications, Liberty will utilize the fee revenue to retain a second FTE*