STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Electric Distribution Utilities

Docket No. DE 22-060

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

SETTLEMENT AGREEMENT ON NET METERING TARIFF

This settlement agreement is entered into by and among Public Service Company of New Hampshire d/b/a Eversource Energy ; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty; Unitil Energy Systems, Inc. (together the "Electric Utilities"); the Office of the Consumer Advocate ("OCA"); Clean Energy New Hampshire ("CENH"); Conservation Law Foundation ("CLF"); Granite State Hydropower Association; Standard Power of America; and Walmart Inc. (collectively, the "Settling Parties"). This settlement agreement resolves all issues among the Settling Parties and the Settling Parties unanimously recommend the following: 1) that the net metering tariff structure currently in place shall stay in effect following approval of this settlement agreement by the Commission ("NEM 2.1"); 2) following approval of this settlement agreement by the Commission, any project newly enrolled in net metering ("NEM") while NEM 2.1 is in effect shall have the option to lock into NEM 2.1 for a 20-year term from the time of enrolling in net metering ("Legacy Period"); 3) implementation of reasonable distributed generation ("DG") application fees; 4) that the Electric Utilities shall, two years from approval of this settlement agreement, file an NEM time-of-use ("TOU") rate with the Commission, along with a petition to open a new docket for consideration of the same; 5) that upon approval of this settlement agreement, the Electric Utilities will undertake a data collection effort to support development of the NEM TOU rate proposal prior to the Electric Utilities' filing their NEM TOU rate proposal with the Commission. The scope and parameters of the data collection effort referred to in item 5), above, will be subject to a stakeholder process comprised of the Settling Parties and the Department of Energy ("Department" or "DOE"), that will commence following approval of this settlement agreement by the Commission. In support of this settlement agreement, the Settling Parties offer the following for the Commission's consideration.

II. SETTLEMENT TERMS

The Settling Parties agree that this Agreement, as described below, should be approved by the Commission as written. The terms of this Agreement constitute an interdependent, comprehensively negotiated whole, and each Settling Party's agreement to each individual term is dependent upon agreement with all terms.

A. Net Metering Tariff and Future Utility NEM Time of Use Rate Design

1. Consistent with RSA 362-A:9 and the New Hampshire 10-Year State Energy Strategy, the Settling Parties agree that NEM 2.1, shall remain at currently tariffed levels for both small and large DG projects following Commission approval of this Settlement Agreement. The Settling Parties further agree that the basis for maintaining the status quo is that the currently effective net metering tariffs have not resulted in any demonstrable unjust or unreasonable cost shifts from one class of customers to another, which is echoed by the conclusions of the DOE VDER study filed to this docket. See Attachment A for further information supporting this position.
2. The Electric Utilities shall continue to apply the large customer tariff terms to projects from 1 to 5 MW as approved in Order No. 26,029, as projects of this size are limited to municipal hosts and there is no evidence of unjust or unreasonable cost for such projects.

The Settling Parties agree that alternative net metering tariffs should not be considered at this time, as any such tariff would likely be less efficient because it would incur additional costs to implement, and, could also incur incremental, ongoing maintenance and administration costs, depending on the nature and complexity of the changes made and the relative benefits to many customers in relation to the costs incurred by all customers.

3. The Settling Parties agree that the Electric Utilities will develop a NEM TOU rate informed by the data collection effort and stakeholder process referenced below in section D, to be submitted two years from Commission approval of this settlement agreement. The Electric Utilities will petition and request for the Commission to open a new docket to adjudicate the Utilities' proposal.

B. Legacy Period

4. The Settling Parties agree that any NEM project that first commences receiving NEM compensation under the NEM 2.1 tariff will be eligible to continue to receive the NEM 2.1 tariff for 20 years from the year in which it first begins net metering (the "Legacy Period"). For a table demonstrating the necessity of the Legacy Period to sustain the solar NEM industry and projects, including NEM project payback periods, please see Attachment B to this settlement agreement.

5. After the expiration of the Legacy Period, the NEM project will default to the tariff currently in effect at that time. At any time during the Legacy Period, the project may elect to transfer to the tariff in effect at the time, but if it chooses to do so, the Legacy Period will terminate, and the project may not return to the NEM 2.1 tariff.

6. To administer the Legacy Period, the Electric Utilities shall do an annual review at the start of each calendar year to move any projects for which the Legacy Period has expired from NEM 2.1 to the net metering tariff in effect at that time.

7. When the Electric Utilities file the NEM TOU rate proposal for a new docket to be opened in two years from approval of this settlement agreement as described in Paragraph 3 above, the Legacy Period may be reexamined as appropriate. Any change to the Legacy Period will only apply on a prospective basis and will not affect NEM projects that began net metering under the NEM 2.1 tariff prior to such change.

C. Application Fees

8. In the interest of minimizing cost shifts due to net metering, the Settling Parties agree that it is appropriate to implement reasonable net metering application fees, so that those who benefit most directly benefit from net metering are bearing an appropriate share of the costs. The Settling Parties recommend the fee structure detailed in Attachment C to this settlement agreement, and summarized below.

9. The Electric Utilities shall collect the application fees and apply them to the eligible utility costs detailed in Attachment C. Should the fees collected exceed the qualifying costs, the Electric Utilities shall each use an existing annual reconciling mechanism to credit any excess fee revenue to all customers.

10. The Electric Utilities may petition the Commission to propose changes to the fee levels and structure to better address costs, as necessary.

11. The Settling Parties agree to the following fees based on project size:

- Up to and including 25 kW: $200
- Greater than 25kW kW to 100 kW: $500
- Greater than 100 kW: $1,000

Further detail regarding the fee collection, application to costs, and crediting to customers can be found in Attachment C.

D. Data Collection Effort and Stakeholder Process

12. The Settling Parties agree that the Electric Utilities shall undertake an 18-month data collection effort that further elucidates the costs and benefits of NEM to residential customers. The Settling Parties shall, following approval of the settlement agreement by the Commission, confer and agree upon the data elements to be collected.

13. Any customer sensitive data will be collected only after explicit customer consent, which shall be acquired by the Electric Utilities using a consent agreement or by including in the data questionnaire a request for customer consent, examples of which are included as Attachment D.

14. The data collection effort and stakeholder process will conclude prior to the submittal of the petition and NEM TOU proposal of the Electric Utilities and will be used to inform such proposal.

III. GENERAL PROVISIONS

The Settling Parties agree that all testimony and supporting documentation may be admitted as exhibits for purposes of consideration of this settlement agreement. Assent to admit all direct testimony without challenge does not constitute agreement by the Settling Parties that the content of the written testimony is accurate nor is it indicative of what weight, if any, should be given to the views of any witness. Reflecting the intent of this settlement agreement, the Settling Parties agree to forego cross-examining witnesses of the Settling Parties regarding their pre-filed testimony, and therefore, the admission into evidence of any witness's testimony or supporting documentation shall not be deemed in any respect to constitute an admission by any party to this settlement agreement that any allegation or contention in this proceeding is true or false, except that the sworn testimony of any witness shall constitute an admission by such witness.

This settlement agreement is expressly conditioned upon the Commission's acceptance of all of its provisions without change or condition. All terms are interdependent, and each Settling Party's agreement to each individual term is dependent upon all Settling Parties' agreement with all terms. If such complete acceptance is not granted by the Commission, or if acceptance is conditioned in any way, each of the Settling Parties shall have the opportunity to amend or terminate this settlement agreement or to seek reconsideration of the Commission's decision or condition. If this settlement agreement is terminated, it shall be deemed to be withdrawn and shall be null and void and without effect and shall not constitute any part of the record in this proceeding nor be used for any other purpose. The Settling Parties recommend approval of this settlement agreement before the Commission. The Settling Parties also agree that they shall not oppose this settlement agreement before any regulatory agencies or courts before which this matter is brought, but shall take all such action as is necessary to secure approval and implementation of the provisions of this settlement agreement in the instant docket.

The Commission's acceptance of this settlement agreement does not constitute continuing approval of or precedent regarding any particular issue under this docket, but such acceptance does constitute a determination that this settlement agreement and each and all of its provisions are just and reasonable. All discussions leading to and resulting in this settlement agreement have been conducted with the understanding that all offers of settlement and discussion relating to these terms are and shall be protected and treated as confidential and privileged, and shall be so without prejudice to the position of any party or participant representing any such offer or participating in any such discussion, and are not to be used in any manner in connection with this proceeding, any further proceeding, or otherwise. Further, the settling parties agree that the settlement agreement and settlement discussions are not intended to prejudice, be used in any manner against, or bind parties to any positions in subsequent dockets, except as related to enforcement of the terms of the settlement agreement. Finally, the Settling Parties reiterate that approval by the Commission and implementation of the terms of this settlement as proposed will result in rates that are just and reasonable.

This Agreement may be executed by facsimile or electronically and in multiple counterparts, each of which shall be deemed to be an original, and all of which, taken together, shall constitute one agreement binding on all of the Settling Parties.

IN WITNESS WHEREOF, the Settling Parties have caused this Agreement to be duly executed in their respective names by their authorized representatives, each being fully authorized to do so on behalf of the party represented.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/ A EVERSOURCE ENERGY

By:__ ________________ August 1, 2024
Jessica Chiavara, Esq.
Senior Counsel

LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP. d/b/a LIBERTY

By:____________________________ August 1, 2024
Michael J. Sheehan, Esq.
Director, Legal Services

UNITIL ENERGY SYSTEMS, INC.

By:__ __Patrick H. Taylor___________ August 1, 2024
Patrick H. Taylor, Esq.
Chief Regulatory Counsel

OFFICE OF THE CONSUMER ADVOCATE

By:__ ____________________________ August 1, 2024
Donald M. Kreis
Consumer Advocate

CLEAN ENERGY NEW HAMPSHIRE

By:___/s/ Sam Evans-Brown_________ August 1, 2024
Sam Evans-Brown
Executive Director

CONSERVATION LAW FOUNDATION

By:____/s/ Nicholas Krakoff__________ August 1, 2024
Nicholas Krakoff, Esq.
Staff Attorney

GRANITE STATE HYDRO ASSOCIATION

By:_ __________________________ August 1, 2024
Madeleine Mineau
Chief Operating Officer, Essex Power Services

STANDARD POWER OF AMERICA

By:___/s/_Robert Hayden_________ August 1, 2024
Robert Hayden
President

WALMART, INC.

By:___/s/ Melissa Horne_________ August 1, 2024
Melissa Horne, Esq.
Of Counsel, Higgins Cavanagh & Cooney, LLP

TABLE OF ATTACHMENTS

Q: Do current net metering tariffs balance the interests of customer-generators with those of non-net metered customers?

A: The Joint Utilities believe they do. A large portion of credit provided to customer-generators through the net metering tariff is directly tied to the wholesale cost of energy reflected within default service rates and generally avoided or realized through utility market activity. This ensures a large portion of net metering credit remains market-based and distributed generation development in New Hampshire is market-driven, as has been demonstrated through recent increases in solar deployment in response to changes in energy supply rates. This shows that the current net metering tariff encourages customers to make investment decisions based on real market conditions, and not just level of subsidization.

Current net metering tariffs do risk shifting costs to non-net metered customers by providing credit in excess of the wholesale market value of energy, in this instance, the full default service rate, along with a portion of distribution and transmission rates, but the risk of significant cost shifting in New Hampshire is mitigated by several factors. The current net metering tariff limits credit for distribution and transmission values to only small customer-generators, providing credit for excess generation at only 25 percent of the distribution rate and providing credit for only kWh-based retail rates limits the amount of credit provided to New Hampshire customer-generators that may exceed the wholesale energy market value of energy and risk shifting costs to non-net metered customers. Net metering tariff designs which have more expansive customer eligibility or issue credits for larger portions of retail rates (i.e. for rates other than supply-related rates) are at higher risk of shifting costs to non-net metered customers.

The Joint Utilities also generally agree that distributed generation facilities can provide greater benefits than larger generation resources by reducing line losses, lowering peak loads on portions of the distribution system and diversifying energy resources. These benefits are more difficult to objectively quantify and are likely to vary based on resource type and location on the electric power system, but they should be considered in any assessment of the balance of Customer-Generator interests with those of non-net metered customers. This is consistent with the 2022 update to the New Hampshire Ten Year State Energy Strategy, which states: "**Having a diverse resource mix can help ensure a secure, reliable, and resilient energy system.**" (New Hampshire 10-Year State Energy Strategy at page 39, emphasis in original).

The actual costs and benefits of distributed generation facilities are difficult to completely validate and the current net metering structure does create a risk that electric power system costs could be shifted from net metered customers to non-net metered customers. However, the Joint Utilities do not believe the current net metering structure is creating a clear or significant imbalance between the interests of net metered and non-metered customers that requires the Commission to address through significant revisions to the existing net metering tariff.

Q: Should the Commission implement new alternative net metering tariffs?

A: The Joint Utilities do not recommend new alternative net metering tariffs at this time. The current net metering tariffs are not creating clearly unbalanced outcomes that merit correcting. A growing number of New Hampshire residents and businesses are increasingly able to make renewable energy choices that reduce their electric bills and introduce potential indirect benefits that are realized by all customers. Moreover, the current net metering tariff is a workable model that is administratively efficient and aligned with technical capabilities, further ensuring an equitable net metering program. If the Commission were to consider alterations to the existing tariff, the Joint Utilities recommend that the Commission consider only limited adjustments to the existing net metering tariffs, and that any such adjustments maintain the level of facility of administration and work within respective technical capabilities and processes to prevent any incremental administrative or equipment and system costs. Costs that are not necessarily commensurate with benefits would have an overall effect of diluting the cost effectiveness of the New Hampshire net metering program, increasing the cost shift to non-net metered customers.

Q: Should the Commission consider alternative rate structures, including time-based tariffs?

A: Alternative rate structures are not necessary right now and would not be practicable or necessarily appropriate for incorporation into a net metering program in New Hampshire. Current rate structures provide adequate opportunity for New Hampshire customers to

Request from: New Hampshire Public Utilities Commission

Request:

Would any cross subsidization between customer generators and (non-customer generator) ratepayers be appropriate and acceptable?

Response:

No rate structure recovers from each individual customer the exact cost to serve that customer – cross subsidies are always present. In its approval of the current net metering structure in Docket No. DE 16-576 the Commission concluded that there was "little evidence of *significant* cost-shifting from DG customers to customers without DG" (Order No. 26,029 at 72, emphasis added). The reference to significant cost-shifting suggests that the Commission previously found the relationship between customer generators and (non-customer generator) ratepayers was just and reasonable when approving the compensation level of customer generators to as permitted by RSA 362-A:9 to enable net metering. The standard of "unjust and unreasonable cost shifting" is also explicitly called out in RSA 362-A:9, XVI(a) as something the Commission should consider when developing net metering tariffs, which pretty clearly indicates that some level of cost shifting is warranted to support New Hampshire's net metering policy.

The parties to this response agree with the Commission's position in the last net metering docket, which is why the utilities testified that current compensation levels have not demonstrated a significant level of cost shifting, and that any cost shifting that may be present is justified by the policy objectives that net metering compensation sustains, as the parties believe that this is consistent with New Hampshire law.

CENH has presented analysis that indicates there are oversetting cost factors that more than compensate non-NEM customers for any current costs of supporting NEM based on current levels of NEM customers in NH and levels likely in the near future.

Request from: New Hampshire Public Utilities Commission

Request:

How do the prior studies completed in dockets related to net-metering support the parties' positions in this docket?

Response:

The parties' various positions are informed by the totality of relevant circumstances surrounding net metering and the evolution of the distributed generation ("DG") and clean energy industries as they specifically apply to New Hampshire. That is to say that any decision regarding the compensation level for net metered customer-generators is closely tied to a constellation of characteristics that is temporally specific. Reports from previous dockets, while informative as to the history of past or current compensation levels, are not necessarily indicative of what is appropriate or justified in this docket and for compensation moving forward, so those reports or studies are not necessary or germane to the party positions in this docket.

The Joint Utilities' position is supported by their collective experience operating the electric power system and administering net metering tariffs, as well as the general findings of prior studies. In particular, the initial pre-filed testimony of the Joint Utilities explains that:

> *.....distributed generation facilities can provide greater benefits than larger generation resources by reducing line losses, lowering peak loads on portions of the distribution system and diversifying energy resources. These benefits are more difficult to objectively quantify and are likely to vary based on resource type and location on the electric power system, but they should be considered in any assessment of the balance of Customer-Generator interests with those of non-net metered customers.* (Joint Utility Testimony at 11)

The Joint Utilities' testimony is generally consistent with the results of the New Hampshire Department of Energy's Locational Value of DER Study, conducted pursuant to the Commission's Order in Docket No. 16-576 and which is to be administratively noticed in this docket, which estimated a benefit of capacity avoidance while concluding it may range from under $1/kW to over $4,000/kW based on location (LVDG Study, Executive Summary at vii). This response does not characterize the position of any party on the substance of the VDER study.

Request from: New Hampshire Public Utilities Commission

Request:

Is the utility default service rate the ppropriate rate to compensate generation for net metering parties? If so, why?

Response:

The Joint Utilities recommended in their Direct Testimony in this docket that the Default Service rate is an appropriate and efficient compensation credit for the electricity supply rate component for excess generation from customer-generators. Please refer to the Direct Testimony of the Joint Utilities at:

Page 10, Lines 3-11
Page 14, Lines 1-5

Please also see the Rebuttal Testimony of the Joint Utilities at Page 17, Lines 5-10. The CENH testimony also supports using the utility default service rate for setting the NEM electricity supply rate component of NEM rates. *See* Testimony of David P. Littell on Behalf of Clean Energy NH, NH PUC Dock. No. DE 22-060 (Dec. 6, 2023), pp. 7, 10, 15- 22, 32-33. 36.

Setting the NEM credit level for electricity supply at the utility default service rate has encouraged the development and expansion of distributed clean energy, and there is no evidence that this level of compensation creates unjust cost shifting. In addition, the DOE VDER study indicates that there is no significant or unjust cost shifting at the current level of compensation.

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

TESTIMONY OF

David P. Littell on behalf of
Clean Energy New Hampshire

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

Docket No. DE 22-060

December 6, 2023

testify to the balance between value and costs. The costs are quite modest, and the benefits are substantial for all ratepayers. The benefits are even greater to NEM-customers. In total, the substantial net benefits are achieved at a very modest cost. Those benefits for all customers exceed the costs even without accounting for environmental benefits.

Q. When you say benefits to all customers exceed the costs, can you clarify?

A. The costs (as analyzed by the Dunsky NH VDER Study and confirmed by Tom Beach and other studies) are substantially below the value of the DERs in the NEM program.

Q. How does New Hampshire's cost to benefit compare to other New England states?

A. Since other New England states NEM programs pay more for the same DER kWh of energy, without doing quantitative analysis, it is fairly clear that New Hampshire's NEM 2.0 program procures more value per dollar than other New England states.

Q. Is New Hampshire more frugal than other New England states?

A. Yes. New Hampshire's NEM 2.0 program is both more frugal and more thrifty than other New England states. None of the recommendations in this testimony would vary New Hampshire's status as the most frugal and thrifty New England state on net energy metering.

Q. Has DER activity increased in New Hampshire?

A. DER activity increased in New Hampshire and across the region in recent years largely as a result of the price of energy. This is a natural and expected response to increase in energy prices. Price drivers for energy include a constrained gas supply: gas is increasingly being exported from the U.S. Multiple international markets, including European markets, have experienced severe supply disruptions with the February 2022 Russian invasion of the Ukraine. As a result, prices of petroleum and gas have increased and severely increased over the last year and half.

**THE STATE OF NEW HAMPSHIRE
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TESTIMONY OF

**R. Thomas Beach
on behalf of
Clean Energy New Hampshire**

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Docket No. DE 22-060

December 6, 2023

- **9.54% factor applied to both avoided transmission costs and transmission lost revenues.** The Dunsky RBI model applies this factor to both the avoided transmission costs and transmission lost revenues, dramatically reducing both. Dunsky says that "the rate impacts assessment assumes only the portion [of transmission costs] attributable to the New Hampshire load as a percentage of the ISO-NE system, which is approximately 9.54%."[20] But New Hampshire ratepayers pay in their rates for 100% of the New England transmission costs allocated to them, and they can avoid 100% of New England ISO transmission charges allocated to the New Hampshire utilities if they reduce their demand during the hours when transmission costs are assessed. This is what is correctly assumed in Dunsky's avoided cost model, but not in its RBI analysis. This 9.54% factor should be eliminated.

In addition, the Dunsky RBI model predates the joint testimony of the utilities proposing, in concept, application fees for new NEM participants. The utilities then supplemented their testimony in discovery, providing a straw proposal for such fees. As discussed in Mr. Littell's testimony, CENH does not oppose the implementation of reasonable application fees, provided the utilities also commit to providing timely service in interconnecting DG customers. An application fee would provide a revenue stream to offset some of the program administration costs included in the Dunsky RBI analysis.

Q: Have you re-calculated Dunsky's RBI results based on all of the issues you have identified in your testimony?

A: Yes. My revised RBI results use (1) Dunsky's updated avoided costs, (2) modifications to address the inconsistencies and problems in the RBI analysis noted above, and (3) revenues from an application fee (based on the utilities' straw proposal), then add (4) marginal line losses in all hours, and finally incorporate (5) the revised avoided distribution costs presented in Table 1 above (with a PCAF-based allocation across hours). **Table 2** shows the cumulative impacts of each of these changes, in terms of the average bill impacts on non-participating Eversource ratepayers over the years 2021-2035, when these changes are made, step by step, to the Dunsky RBI analysis.

Several points about Table 2 need to be emphasized, so that what the table shows is clear. First, the bill impacts shown in the table represent the average change in

[20] See Dunsky Report, at Appendix F.2.2.

I have performed analyses similar to the one shown in Table 2 for Liberty and Unitil. The bottom-line results for all three utilities are presented in Table 3, showing the bill impacts after making all changes to the RBI analysis discussed in my testimony.

Table 3: *Impact of Changes to RBI Analysis – Non-participating Customers*

Utility	**2021 – 2035 Bill Impact (%)**		
	Residential	SG	LG
Eversource	- 0.51%	- 0.70%	- 1.05%
Liberty	+ 0.30%	- 0.15%	- 1.07%
Unitil	+ 0.19%	- 0.14%	- 0.08%
Average	**- 0.4%**	**- 0.6%**	**- 0.9%**

Note: **Table 3** includes all **Table 2** changes for each utility. Average results are weighted by each utility's sales.

Table 3 shows that, when all of these changes are made, the result is that future DER deployment in New Hampshire will result in small decreases in the rates and bills for all non-participating commercial ratepayers and for Eversource's non-participating residential customers. There would be slight rate and bill increases for the non-participating residential customers of Liberty and Unitil. On average statewide, across all three utilities, net metered DG installations will provide a small net benefit to customers, including to customers who do not install solar. Although the changes that I have made to the Dunsky RBI analysis have small impacts, they do reverse the findings of the Dunsky Report that future DER development would result in slight rate and bill increases for non-participants. My revisions support a conclusion that future DER deployment in New Hampshire will result in slight rate and bill decreases for most non-participants.

IV. IMPACTS OF RECOMMENDED CHANGES TO NET METERING

Q: In light of the results of your analysis, what adjustments could be made to NEM policy in New Hampshire?

A: CENH has asked me to assess whether adjustments to the current design of the export rates paid to solar customers could be made, without burdening non-participating ratepayers, in order to provide a stronger incentive for customers to adopt DERs. I used

STATE OF NEW HAMPSHIRE
Before the
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Docket No. DE 23-060
ELECTRIC DISTRIBUTION UTILITIES
Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators

Responses of David Littell on behalf of Clean Energy NH to of the Granite State Hydropower Association to Clean Energy NH Data Requests, Set 1
January 10, 2024

Please refer to the testimony of David Littell on behalf of Clean Energy NH filed on December 6th at page 40 line 20 which states the following:

“Q. What is the second recommendation?

A. The second recommendation is that, assuming NEM 3.0 is any different than NEM 2.0, to ask for the same effective grandfathering for NEM customers taking NEM 3.0 after the Commission’s new program becomes effective, so 20 years of NEM for new customers.”

3. Can you please clarify under your proposal what would be the starting point in time for the 20-year term of grandfathering under NEM 3.0?

Answer: The starting point for the proposed 20-year term for NEM would be when the facility begins to physically generate power under the NEM tariff. In the case of a newly constructed NEM facility that requires utility permission to interconnect, synchronize with the grid, and energize, that starting point is the date the customer is approved to energize and operate with the utility interconnection facilities. In the case of facilities that energized some time prior, that start date would be the date the facilities began to participate in an NEM tariff.

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4. Please clarify what is meant in your response by "new customers".

Answer: New customers in this CENH proposal for a 20-year term refers to customers who take NEM service for the first time under any NEM tariff. The purpose of this 20-year NEM proposed term is to provide adequate and stable customer expectations that allow for project financing including re-financing associated with hydro facility (or any resource type) upgrades and commercial transactions. If there is a risk that NEM qualifications or payment will vary in the future, it can present commercial and transactional risk issues that are not supportive of competitive distributed resource markets in New Hampshire.

for customer-generators than New Hampshire and tended to, through multiple iterations of net metering tariffs, provide for predictable rates that support distributed resource development over many years for interested customers.

As set forth in Mr. Littell's testimony, Connecticut sets a several rates for PV customers compensation. Connecticut has transitioned from a pure NEM regime to two different distributed solar compensation regimes for residential customers with PV systems up to 25 kW and non-residential customers up to 5,000 kWs of PV. PURA sets a rate for a "buy-all" energy and RECs annually which is $0.3189/kWh in 2024 for residential customers and can be increased for low-income customers or customers in economically distressed area. For non-residential PV customers, the "buy-all" rates start at $199.82/MWh for projects with generating capacity up to 200 kW. There is a competitive procurement above 200 kW to 5,000 kW for non-residential new system.

The alternative compensation scheme in Connecticut, at the customer's option, provides for "netting" of net excess energy not used onsite and all RECs at a credit equal to the retail kWh charge for that customers rate class. Vermont has a very complex system to ensure solar development away from sensitive areas and provides a blended net metering rate which in 2024 was re-set at $0.18398/kWh and subject to various "Siting Adjustor Factors" and other factors.

In Massachusetts, customers with eligible PV up to 5,000 kW can qualify net excess generation compensation for up to 100% retail basic service, distribution, transmission on a per kWh basis for PV up to 25 kW, and solar facilities serving onsite local or governmental facilities. A lower net credit is available for other renewable facilities is " based on 60% of the excess kWh generated, as opposed to 100%." Hydro in Massachusetts can net up to 2,000 kW for credit set at retail basic service. The utility description above provides more detail on Massachusetts.

Maine's programs, called Net Energy Billing take two different forms, full NEM for residential and small business customers known as Maine's KWH credit. The KWH credit includes the default service, transmission, and distribution charges. Likewise, Rhode Island provides a full credit for the default service charges, as well as charges for distribution, transmission, and transition, but in Rhode Island, DG customers are always responsible for customer and demand related charges

Using the same format as the NH summary of NH's NEM, Maine's and Rhode Island's programs are summarized graphically below as they have different compensation levels but similar structure whereas the Connecticut, Massachusetts, and Vermont programs are not structured similarly to New Hampshire's so do not lend themselves to the same tables for comparison.

Maine (KWH Program)	
Bill Component	**Credit or Charge**
Demand Charge	Not Applicable
Min. Bill Charge	Charge
Default Service (Energy)	Full Credit
Distribution	Full Credit
Transmission	Full Credit
System Benefits	Charge
Stranded Cost	Charge

Rhode Island	
Bill Component	**Credit or Charge**
Demand Charge	**Charge**
Customer Charge	Charge
Default Service (Energy)	Full Credit
Distribution	Full Credit
Transmission	Full Credit
Transition Charge	Full Credit

For NH Systems less than and equal to 100 kWac

Bill Component	NEM 1.0 (Standard NEM)	NEM 2.0 (Alternative NEM)
Customer Charge	Yes	Yes
Demand Charge (if applicable)	Yes	Yes
Default Service (Energy)	Full Credit	Full Credit
Distribution	Full Credit	25% Credit
Transmission	Full Credit	Full Credit
System Benefits	Full Credit	No Credit
Stranded Cost	Full Credit	No Credit
Storm Recovery	Full Credit	No Credit
Credit Mechanism (end of each billing cycle)	Net kWh Carried Forward	kWh converted to monetary credit. Monetary credit carried forward as a bill credit.

For NH Systems larger than 100 kW up to 1 MWac

Bill Component	NEM 1.0 (Standard NEM)	NEM 2.0 (Alternative NEM)
Customer Charge	Yes	Yes
Demand Charges	Yes	Yes
Default Service (Energy)	Full Credit	Full Credit
Distribution	No Credit	No Credit
Transmission	No Credit	No Credit
System Benefits	No Credit	No Credit
Stranded Cost	No Credit	No Credit
Storm Recovery	No Credit	No Credit
Credit Mechanism (end of each billing cycle)	Net kWh Carried Forward	kWh converted to monetary credit. Monetary credit carried forward as a bill credit.

The above graphics for New Hampshire NEM compensation can also be found here: (NHPUC, What is Net Metering, , **Net Metering Tariff Overview 2020**, on the web: https://www.puc.nh.gov/sustainable%20energy/Net%20Metering/Net_Metering.html.)

Attachment B –
CENH Pro-forma of new NEB Solar Projects in New Hampshire

CENH has simplified the pro forma summary for NEB solar projects in New Hampshire provided to all parties on March 28, 2024. (This version eliminates the transmission credit scenarios for projects > 1 MW which are not part of this settlement.)

The calculations includes median assumptions for the variables that impact new solar NEB project in New Hampshire for projects of 1 MW and qualifying municipal projects of 4.99 MW. The pro formas scenarios lay out pro forma revenues for those two solar projects that begin in 2031 with the current 2041 NEM cliff, for those two solar projects that begin in 2026 with the current 2041 NEM cliff, and finally for those two solar projects that begin in 2026 with a 20-year term recommended in the settlement.

The after-tax internal rates of return (IRR) vary from a negative 2.68 percent to a positive 5.78 percent among these six scenarios.

The pro forma show median project revenue including::

1. Solar power production;
2. Development expenses;
3. Interconnection costs;
4. Net metering discount,
5. Renewable Energy Certificate values;
6. Financing costs;
7. Land lease costs;
8. Taxes; and
9. Operations & maintenance cost.

The pro formas indicate that, even with the 20 year term, solar projects under the current NEM tariff provide relatively low returns for developers, even as they may offer significant value to business and local government. The returns for future projects with current 2041 cliff in place will become negative soon as illustrated by the first two pro formas scenarios. These pro forma scenarios illustrate the modest positive returns NEM solar projects will be able to pursue under the settlement terms.

New Hampshire Net Metering Analysis																						
	Year		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Scenario 1A: 1 MW AC with current Eversource Net Metering Rate and 2041 Net Metering Cliff with Operations beginning in 2031	Net Metering Rate1	-						$0.1201	$0.1225	$0.1250	$0.1275	$0.1300	$0.1326	$0.1353	$0.1380	$0.1408	$0.1436					
	AC Size (kW)	1,000																				
	After-tax IRR	-2.68%																				
	Footnotes																					
	1 Assumes 2.0% per annum net metering rate escalation																					
Scenario 1B: 4.99 MW AC with current Eversource Net Metering Rate and 2041 Net Metering Cliff with Operations beginning in 2031	Net Metering Rate1	-						$0.1201	$0.1225	$0.1250	$0.1275	$0.1300	$0.1326	$0.1353	$0.1380	$0.1408	$0.1436					
	AC Size (kW)	4,999																				
	After-tax IRR	-0.59%																				
	Footnotes																					
	1 Assumes 2.0% per annum net metering rate escalation																					
Scenario 2A: 1 MW AC with current Eversource Net Metering Rate and 2041 Net Metering Cliff with Operations beginning in 2026	Net Metering Rate1	-	$0.1201	$0.1225	$0.1250	$0.1275	$0.1300	$0.1326	$0.1353	$0.1380	$0.1408	$0.1436	$0.1464	$0.1494	$0.1524	$0.1554	$0.1585					
	AC Size (kW)	1,000																				
	After-tax IRR	1.57%																				
	Footnotes																					
	1 Assumes 2.0% per annum net metering rate escalation																					
Scenario 2B: 4.99 MW AC with current Eversource Net Metering Rate and 2041 Net Metering Cliff with Operations beginning in 2026	Net Metering Rate1	-	$0.1201	$0.1225	$0.1250	$0.1275	$0.1300	$0.1326	$0.1353	$0.1380	$0.1408	$0.1436	$0.1464	$0.1494	$0.1524	$0.1554	$0.1585					
	AC Size (kW)	4,999																				
	After-tax IRR	3.45%																				
	Footnotes																					
	1 Assumes 2.0% per annum net metering rate escalation																					
Scenario 3A: 1 MW AC Eversource current Net Metering Rate and 20 Year Net Metering Term with Operations beginning in 2026	Net Metering Rate1	-	$0.1088	$0.1110	$0.1132	$0.1155	$0.1178	$0.1201	$0.1225	$0.1250	$0.1275	$0.1300	$0.1326	$0.1353	$0.1380	$0.1408	$0.1436	$0.1464	$0.1494	$0.1524	$0.1554	$0.1585
	AC Size (kW)	1,000																				
	After-tax IRR	4.09%																				
	Footnotes																					
	1 Assumes 2.0% per annum net metering rate escalation																					
Scenario 3B: 4.99 MW AC with current Eversource Net Metering Rate and 20 Year Net Metering Term with Operations beginning in 2026	Net Metering Rate1	-	$0.1088	$0.1110	$0.1132	$0.1155	$0.1178	$0.1201	$0.1225	$0.1250	$0.1275	$0.1300	$0.1326	$0.1353	$0.1380	$0.1408	$0.1436	$0.1464	$0.1494	$0.1524	$0.1554	$0.1585
	AC Size (kW)	4,999																				
	After-tax IRR	5.78%																				
	Footnotes																					
	1 Assumes 2.0% per annum net metering rate escalation																					

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 25 kW	$200
Greater than 25 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 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:** An annual report and reconciliation of application fees shall take place in each Company's annual filing for the reconciling mechanism selected for crediting any overcollections back to customers as described below.. 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 (1) total application fees collected in the prior year as well as (2) 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 an existing reconciling mechanism[1]. 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 a reconciling mechanism without prior authorization by the Commission. However, the Commission may approve changes to fee amounts in any Companies applicable annual filing to achieve better alignment of revenues and administrative expenses in future years.

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

   Performance Reporting: The Joint Utilities shall provide quarterly reports that include application processing metrics and narrative descriptions of how each utility is managing interconnection processes to streamline and expedite the experience of customer-generators.

[1] Eversource will credit applicable costs to Stranded Cost Recovery Charge: Unitil will credit applicable costs to XX; Liberty will credit applicable costs to XX

Application processing metrics may be adjusted or expanded based on stakeholder input and Distribution Company experience, but will initially include:

1. Total number of complete applications submitted
2. Total number of Permissions to Operate issued
3. Total complete applications by MW submitted
4. Total MW issued Permissions to Operate
5. Total Average time to issue Contingent Approvals
6. Percent of applications requiring customer correction (Eversource and Liberty)
7. Average time to complete the meter installation after complete and correct submittal of Completion Documents

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.

Direct Ownership Customer Disclosure Form

CUSTOMER INFORMATION	
Customer Name:	
Name on Electric Bill (if different):	
Site Address:	
City, State, Zip:	
Phone:	
Email:	
INSTALLER CONTACT INFORMATION	**PRIMARY SERVICE CONTACT INFORMATION**
Company:	Company:
Street Address:	Street Address:
City, State, Zip:	City, State, Zip:
Phone:	Phone:
Email:	Email:

CONTRACT, COST, AND ESTIMATED PERFORMANCE INFORMATION	
System Size (kW DC):	
System Size (kW AC):	
Where in the contract is the warranty information located?	
Are all warranties transferrable?	☐ Yes or ☐ No
Has a shading analysis been completed for the property?	☐ Yes or ☐ No
How much production is expected to be lost due to shading? (%):	
Estimated Year One Production (kWh):	
What is the Final Purchase Price for the system before any rebates or other incentives ($ and $/watt)	**$** **$/Watt**
Estimated net average monthly savings ($)	**$**
Starting utility rate used to estimate net average monthly savings:	
Escalator rate used to estimate net average monthly savings:	
FINANCING INFORMATION*	
Does the above-listed Final Purchase Price include any dealer fees or other finance-related charges that would not be charged to a customer in a similar cash transaction?*	☐ Yes or ☐ No
Amount of dealer fees or other finance-related charges in the Final Purchase Price ($):	**$**
OTHER INFORMATION	
Describe any system performance or electricity production guarantees:	
Have you and the customer discussed the condition of the roof and the potential for removing and reinstalling the array in the event that repair or replacement of the roof is needed?	☐ Yes or ☐ No

KEY RESPONSIBILITIES CHECKLIST*	PRIMARY INSTALLER	OWNER
System Operations and Maintenance		
Submission of Interconnection Application to Utility	X	
Securing Required Permits		
Obtaining Engineering Approvals		
Scheduling Inspections		
Participation in Inspections		
Copy of Customer-Contractor Contract/Agreement		
OWNERSHIP OF INCENTIVES	**PRIMARY INSTALLER**	**OWNER**
Owner of Renewable Energy Attributes		**X**
Owner of Federal Investment Tax Credit		**X**

* If your System is financed, carefully read any agreement and disclosure forms provided by your lender. Your installer may not be aware of the terms of your financing agreement, which may include fees not listed above. This disclosure does not contain the terms of your financing agreement. If you have any questions about your financing arrangement, contact your finance provider before signing a Contract.

I, ________________________________, hereby confirm that I have received and understand the information above and understand the information. I further confirm that I have had a chance to ask questions of my Installer and have received sufficient answers, if applicable.

Customer Signature	Date

I, _____________________________, hereby confirm that the information provided on this form is true and accurate and that any factual misrepresentations on this Customer Disclosure Form may be grounds for enforcement action by the New Hampshire Public Utilities Commission up to and including permanent removal from participation in Net Metering.

Signature of Installer Representative	Date

Third Party Ownership Customer Disclosure

CUSTOMER INFORMATION	SYSTEM OWNER CONTACT INFORMATION
Customer Name:	Company:
Name on Electric Bill:	Street Address:
Site Address:	City, State, Zip:
City, State, Zip:	Phone:
Phone:	Email:
Email:	
INSTALLER CONTACT INFORMATION	**PRIMARY SERVICE CONTACT INFORMATION**
Company:	Company:
Street Address:	Street Address:
City, State, Zip:	City, State, Zip:
Phone:	Phone:
Email:	Email:

CONTRACT, COST, AND ESTIMATED PERFORMANCE INFORMATION			
System Size (kW DC):		System Size (kW AC):	
Contract Effective Date:		Contract End Date:	
Option to Renew	☐ Yes or ☐ No	Option to Buyout	☐ Yes or ☐ No
Starting Rate PPA/Lease Rate (Select one)		$_________/kWh	$_________/month
Lease down payment and/or pre-payment amount		$	
Contract Rate Increase Frequency		☐ Monthly or ☐ Annually or ☐ N/A	
Amount of Rate Increase			
Has a shading analysis been completed for the property?		☐ Yes or ☐ No	
How much production is expected to be lost due to shading? (%):			
Estimated Year One Production (kWh):			
Estimated Year One Payments ($):		$	
Estimated Year One Customer Net Savings ($):		$	
Starting utility rate used to estimate net year one savings:		$_________/kWh	
Escalator rate used to estimate net year one savings:		_________%	
Is the contract transferrable?		☐ Yes or ☐ No	
Where in the contract is the warranty information located?			
Are all warranties transferrable?		☐ Yes or ☐ No	

OTHER INFORMATION	
Describe any system performance or electricity production guarantees:	
Describe opt-out or early termination terms:	
Must the customer continue to make payments in the event of an extended system shutdown?	☐ Yes or ☐ No
Will a filing be recorded in the land records of the customer's municipality pursuant to the contract for this system?	☐ Yes or ☐ No
Describe any protections for the customer in the event that the service provider goes out of business:	

Has the condition of the roof and the potential for removing and reinstalling the array in the event that roof repair or replacement is needed been discussed with the customer?	☐ Yes or ☐ No

KEY RESPONSIBILITIES CHECKLIST**	PRIMARY INSTALLER/OWNER	CUSTOMER
System Operations and Maintenance		
Submission of Interconnection Application to Utility	X	
Securing Required Permits		
Obtaining Engineering Approvals		
Scheduling Inspections		
Participation in Inspections		
Application for Program	X	
Copy of Customer-Contractor Contract/Agreement***		
OWNERSHIP OF INCENTIVES	**PRIMARY INSTALLER/OWNER**	**CUSTOMER**
Owner of Renewable Energy Attributes	X	
Owner of Federal Investment Tax Credit	X	

I, ________________________________, hereby confirm that I have received and understand the information above and understand the information. I further confirm that I have had a chance to ask questions of my Installer and have received sufficient answers, if applicable.

Customer Signature | Date

I, ____________________________, hereby confirm that the information provided on this form is true and accurate and that any factual misrepresentations on this Customer Disclosure Form may be grounds for enforcement action by the New Hampshire Public Utilities Commission up to and including permanent removal from participation in net metering.

Signature of Installer Representative | Date