NH Public Utilities Commission
Docket No. DE 22-060
PUC Record Requests for CPCNH – Responses

Received: November 25, 2024 Date of Response: December 20, 2024
Request Number: **RR-13** Witness: Clifton C. Below

Request:

13. When looking at the current utility default service cost components, which ones would CPCNH recommend including, and not including, in the energy rate for utility net-metered customers. Please list all cost components and their recommended treatment. Would it be the same for residential and commercial customers?

Response:

CPCNH does not recommend excluding any default service components in the utility default service rate for compensation for net metered exports to the grid absent concurrent provision of a credit for avoided transmission costs for net metered systems larger than 100 kw. The Joint Motion for Clarification and Reconsideration of Order No. 27,074, dated December 18, 2024, (at 17, FN8) succinctly summarizes our position in this matter:

> "If the inquiry into Phase IC continues, the Moving Parties ask that the Commission move it to be considered with the Phase II issues in the same phase, as CPCNH intended for those issues to be considered together. CPCNH acknowledged that the default energy service credit alone is undercompensating large customer-generators for their actual value of exported energy, stating "for over 100 KW today, it's not a net cost shift, because of the lack of compensation for avoided transmission cost.· So just getting the full default service rate is still undercompensating compared to the value produced." (Tr. Day 2 at 133:17-22). The premise is that reducing the energy credit would only be fair if a new transmission credit is created for large customer-generators which would result in a net increase in the value of the net metering credit for large customer-generators, but would not be reasonable otherwise. For this reason, adjustments to the default service rate credit should not be considered in isolation, but together with consideration of an added transmission credit."

CPCNH recommends the following rate components be included in the export rate for customer generators greater than 100kW:

1. Avoided transmission cost credit consistent with CPCNH's testimony and briefs in this matter and the benefits identified in Exhibits 8 and 9 in this docket, the Dunsky VDER Study Report and Addendum.

2. Energy supply costs, whether procured at fixed rates selected through competitive solicitations from third party market participants, and/or direct purchases by the utility in the ISO-NE day ahead and real time markets. For Eversource and Liberty this is what they term the "Base [small or large customer] Energy Service Rate", which is inclusive of estimated lines losses from the pooled transmission facilities (PTF) to retail meters. For Unitil it is their power supply charge, or the sum of wholesale suppliers' charges plus direct market purchases by Unitil, adjusted for line losses to the retail meter.
3. An appropriate line loss factor should be used to reflect the fact that local power supplied on the distribution grid will have fewer line losses than regional power supplied over the high voltage transmission grid. CPCNH suggests the use of 2% to 3% or one half the published line loss factors (as applicable to the customer's rate class and service voltage level) until the Commission receives a recommendation from the distribution utilities on the estimated average line loss from the point of customer-generator exports to where load is offset on the distribution grid.
4. Prior period reconciliation for over- and under-recovery of energy supply costs to serve utility default service. For Eversource this is their "Energy Service Adjustment Factor." For Liberty, this is the power supply portion of their "Energy Service Reconciliation Adjustment Factor." For Unitil, this is the portion of "Reconciliation" arising from power supply.

Components two and three are consistent with the Direct Testimony of Clifton C. Below on behalf of CPCNH filed on 12/06/23 at page 23, line 21 through page 27, line 18. That testimony recommended that prior period reconciliations be excluded from the export credit. This recommendation has changed based on how utility default service procurement is changing, as further explained in response to PUC RR-15. Component 1 (Transmission) has been added for clarification that any modifications to the current net metering rate for larger systems would require inclusion of transmission benefits to result in just and reasonable rates in CPCNH's view.

Listed below, the remaining components of the retail default service rate that would be excluded from the utility default service export credit, because they are not values produced or avoided by customer-generators.

- Renewable Portfolio Standard (RPS) charges, called the "Renewable Portfolio Standard Adjustment Factor" by Eversource; the "Renewable Portfolio Standard Adder" by Liberty; and the "Renewable Portfolio Standard (RPS) Charge" by Unitil (which is also inclusive of prior period reconciliation of RPS costs and charges)..
- RPS Reconciliations, called the "Renewable Portfolio Standard Reconciliation Adjustment Factor" by Eversource and the RPS portion of Liberty's "Energy Service Reconciliation Adjustment Factor."
- General and Administrative Costs, including utility costs to administer default service, working capital costs, bad debt, prior period reconciliations of over and under

collection of these costs, and in the case of Unitil, the default service portion of the annual PUC [now DOE] Assessment and GIS Support Payments. Eversource calls these "A&G Adjustment Factor" (apparently inclusive of prior period reconciliation) and "[Small or Large Customer] Working Capital Adjustment Factor." Liberty calls these "Energy Service Cost Reclassification Adjustment Factor," which is apparently inclusive of prior period reconciliations. Unitil does track each of these components; however, it rolls them into "Total Costs." Unitil appears to track prior period under- and over-collection of such costs, but rolls them into "Reconciliation," along with power supply reconciliations.

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Request:

14. For the question above, will CPCNH handle its net-metering customers in the same way?

Response:

CPCNH has not yet developed terms, conditions, and rates for financial compensation for exports to the grid by net metered customer-generators that are not grandfathered into net metering 1.0, the original system of using kWh credits rather than a monetary credit. CPCNH does serve a significant number of customer-generators on NEM 1.0 on utility consolidated billing because the utility nets kWh exports to the grid against kWh consumption in future billing periods, so over time only the net consumption adds to the wholesale load obligation and RPS compliance obligation of each Community Power Aggregation (CPA). CPCNH is thus able to charge a rate for net consumption that covers the cost of power supply and RPS compliance obligation for that net consumption.

For customer-generators on alternative net metering rates that monetize monthly exports to the grid (e.g. NEM 2.0), the utility does not provide a kWh credit for such exports to offset consumption and instead the utilities treats those exports as if they did not exist, zeroing them out in load settlement. As a consequence, CPCNH is unable to offer any monetary credit for those exports, because it does not realize value from reduction in its wholesale load settlement obligation, nor in the cost of its RPS compliance obligation, that is commensurate with the quantity of those reductions.[1]

Terms and conditions, including export credit rates, if and when CPAs are able to properly serve customer-generators that are not on original net metering (NEM 1.0), will be determined consistent with CPCNH's cost sharing agreements and rates policy. These policies and agreements do contemplate the possibility of having different rates and rate structures for different CPAs being served by CPCNH, so net metering rates and terms may vary across CPAs served by CPCNH to some extent.

[1] Those exports do reduce the apparent line losses in Unaccounted for Energy, the benefits of which are socialized to suppliers as an across-the-board reduction in load settlement quantities. As a result, each CPA served by CPCNH, which typically have separate load asset ids, only benefits to the extent of their share of the total load across the utility metering domain.

Any such net metering rates will need to be informed by the approved electric aggregation plan (EAP) of each CPA. As the first EAP approved by the Commission in DE 21-143 on 8/30/22, the City of Lebanon's EAP provided a template on how CPAs may serve net metered customer-generators, which many subsequent EAPs have been modeled on with varying degrees of customization and modifications. Attached is Lebanon Community Power's Attachment 6 to its approved EAP that discusses how net metered customers might receive credit for their exports to the grid. One approach contemplated is to dual bill such customers and, in effect, turn them back into NEM 1.0 customers for the supply portion of their bill.

It should be noted that the approved Lebanon EAP and many, of those subsequently adopted by CPCNH members before we initially launched incorrectly assumed that the utility would net exports by CPA customer-generators against overall consumption in determining the CPA's wholesale load obligation with ISO-NE in accord with RSA 362-A:9, II.[2] For example:

> "The cumulative surplus generation exports of net metered customer-generators will decrease the amount of electricity that Lebanon Community Power will have to purchase from the regional power market to supply other customers in the program. The surplus generation from both NEM 1.0 and NEM 2.0 customer-generators will be tracked and netted out from the program's wholesale load obligations by Liberty Utilities for this purpose." (Lebanon Community Power EAP at ,

As this has not the case to date, no credit or compensation for net metered exports or output to the grid has been approved by CPCNH or any CPCNH CPAs.

[2] "Such output shall be accounted for as a reduction to the customer-generators' electricity supplier's wholesale load obligation for energy supply . . ."

Attachment 6: Lebanon Community Power Net Metering, Group Net Metering and Low-Moderate Income Solar Project Opportunities

Please refer to Attachment 5: Overview of Utility Net Metering Tariffs as context for this section.

RSA 362-A:9, II grants Community Power programs broad statutory authority to offer customer-generators new supply rates and terms for the generation supply component of Net Energy Metering (NEM). The relevant statutory authority is quoted in full below:

> *"Competitive electricity suppliers registered under RSA 374-F:7 and municipal or county aggregators under RSA 53-E determine the terms, conditions, and prices under which they agree to provide generation supply to and credit, as an offset to supply, or purchase the generation output exported to the distribution grid from eligible customer-generators. The commission may require appropriate disclosure of such terms, conditions, and prices or credits. Such output shall be accounted for as a reduction to the customer-generators' electricity supplier's wholesale load obligation for energy supply as a load service entity, net of any applicable line loss adjustments, as approved by the commission. Nothing in this paragraph shall be construed as limiting or otherwise interfering with the provisions or authority for municipal or county aggregators under RSA 53-E, including, but not limited to, the terms and conditions for net metering."*

Lebanon Community Power intends to offer a NEM generation rate and terms to customers with onsite renewable generation eligible for net metering from Liberty Utilities. Note that any non-supply related components of the Net Energy Metering tariff (e.g., credits for transmission and distribution) will continue to be provided to customer-generators directly by Liberty Utilities.

How Lebanon Community Power calculates, accounts for and provides NEM credits to participating customer-generators for the different types of eligible system sizes, customer types and group configurations will have a number of important financial and practical implications for the program and customers in the City.

Lebanon Community Power also anticipates encountering practical challenges of an operational nature in administering net metering and group net metering programs. This is partly because net energy metering continues to evolve in response to new policy and regulatory requirements, and the day-to-day processes that govern the coordination between the program, participating customers and Liberty Utilities are subject to refinement and change over time.

Lebanon Community Power will be one of the first default aggregation programs to launch in Liberty Utilities' service territory, and the process of transferring significant numbers of NEM customers may cause unanticipated issues due to the metering, billing. and data management requirements of this subset of customers. Lebanon Community Power will maintain close coordination with Liberty Utilities to expeditiously resolve any such issues that may occur.

For example, Lebanon Community Power may decide to separately issue supply bills to customers that have installed systems after September 2017.

The advantage in dual-billing this subset of customers stems from what is essentially an accounting irregularity in how Liberty Utilities' billing system and PUC policies currently treat customer-generators taking service under the NEM 1.0 tariff, which applies to systems installed before September 2017, versus the NEM 2.0 tariff, which applies to all systems installed after that date. As context:

- The cumulative surplus generation exports of net metered customer-generators will decrease the amount of electricity that Lebanon Community Power will have to purchase from the regional power market to supply other customers in the program. The surplus generation from both NEM 1.0 and NEM 2.0 customer-generators will be tracked and netted out from the program's wholesale load obligations by Liberty Utilities for this purpose.
- However, for the purpose of netting out of the program's Renewable Portfolio Standard (RPS) compliance requirements, the surplus generation from NEM 1.0 customers is tracked and accounted for differently than it is for NEM 2.0 customers:
    - Surplus generation from NEM 1.0 customers is tracked as a kWh credit that is carried forward to offset the customer's future electricity supply requirements; these kWh credits will be counted as an offset that decreases the total electricity supplied by the program to retail customers in aggregate — which lowers the program's RPS compliance obligation.
    - Surplus generation from NEM 2.0 customers is tracked as a monetary credit that is carried forward to offset the customer's future electricity bills; even though the monetary credit is calculated each month based on every customer's kWh surplus generation, the monetary credit is treated as a re-sale or delivery of power generated by NEM 2.0 customer and provided to other participating customers through the program — it is not treated, in other words, as an offset that decreases the total electricity supplied by program to retail customers in aggregate — and therefore does not lower RPS compliance obligations in the same way.

  The practical consequence of this accounting treatment is that Lebanon Community Power would have to purchase Renewable Energy Certificates for the amount of surplus generation supplied by NEM 2.0 customer-generators (but not NEM 1.0 customer-generators) in the same way as if the program had imported that amount of electricity from the regional wholesale market.

- Taking on the responsibility of billing this subset of NEM 2.0 customers directly may allow Lebanon Community Power to track and account for the impact of their surplus generation in ways that lower the program's RPS compliance obligations and costs. Specifically, the program could credit customers currently on the utility's NEM 2.0 tariff in the same way that NEM 1.0 customers are credited (i.e., using kWh credits to track surplus generation on the supply portion of the bill). Note that RSA 362-A:9,II explicitly grants Community Power programs the flexibility to offer net metered customers either:
    - A "*credit, as an offset to supply*" for their surplus generation, which is equivalent to the NEM 1.0 tariff accounting practices; or
    - To "*purchase the generation output exported*" which is equivalent to how the NEM 2.0 tariff tracks surplus generation.

  Exercising the first option listed above, by offering NEM 2.0 customers a kWh credit tracked as an offset to supply, would allow Lebanon Community Power to harmonize the accounting treatment of NEM 1.0 and 2.0 surplus generation for the purpose of program RPS compliance reporting. This would help lower program rates and is an option that the program may therefore find cost-effective to implement.

Additionally, certain customer-generators currently receiving IRS Form 1099 taxable income from monetary credits under Liberty Utilities' NEM 2.0 tariff may benefit financially from receiving kWh credits for the supply portion of their monthly surplus generation instead.

While dual billing is typically avoided — as it is less convenient for most customers to receive a separate bill from their utility and supplier — customers with onsite generation systems tend to be highly informed on energy issues and respond positively to more active engagement with both their utility and supplier.

Consequently, dual billing may enhance customer satisfaction, awareness and ongoing participation in the program for customer-generators. Furthermore, dual billing could be done electronically, which is more convenient for the customer and will be less costly for the program than sending paper bills.

Furthermore, Lebanon Community Power may be able to create additional value for customer-generators through a combination of dual billing, assistance with metering upgrades and time-varying rate structures. For example:

- Many customer-generators with solar systems may benefit from local programs that help them reduce their full energy bill costs;
- Providing the customer with a separate supply-only bill would allow Lebanon Community Power to also offer a time-varying rate (which may not otherwise be available through Liberty Utilities' billing system);
- Upgrading to an interval meter (if the customer does not have one) and installing onsite battery storage, combined with a time-varying rate, may enable the customer-generator to further lower their overall bill by shifting their pattern of electricity usage at times of high-power prices and constrained generation and transmission capacity. This could also help to manage and lower the program's electricity supply costs in aggregate as well, and thus benefits all participating customers.

Similarly, Lebanon Community Power may be able to streamline the process and cost of installing REC production meters for customer-generators that don't already have one. By registering customer-generators and purchasing their RECs for their onsite power generation Lebanon Community Power could use them to satisfy part of the program's overall RPS compliance requirements. This would allow the program to source RECs locally and would provide an additional source of revenue for customer-generators in the City.

Lebanon Community Power also intends to evaluate ways to enhance the value of the NEM credits that customers receive overall, from both the program and Liberty Utilities. For example, customer-generators may benefit by becoming hosts in Group Net Metering, including by establishing a Low-Moderate Income Solar Project group. The program may be able to streamline the process required to do so, which entails:

- Matching customers interested in becoming members with prospective group hosts;
- Executing a Group Net Metering Agreement together;
- Registering the group with the Public Utilities Commission and Liberty Utilities; and
- Thereafter filing annual compliance reports.

Lastly, NEM tariffs are subject to revision and Lebanon Community Power, through the Coalition, intends to work with Liberty Utilities, participate in Public Utilities Commission proceedings and engage at the Legislature on issues that impact how the tariffs evolve going forward.

Customers are increasingly adopting new energy technologies and expect to be offered rates and services that provide them with new choices and fair compensation based on their investment; the program's ability to assist customers in these ways is heavily dependent on how state policies and utility regulations evolve over time.

Lebanon Community Power will seek to represent the interests of our community and customers in these matters.

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Request Number: **RR-15** Witness: Clifton C. Below

Request:

15. Please explain with an example how CPCNH envisions using the "Base Energy Service Rate" in lieu of the Default Service Rate for energy to implement the compensation mechanisms as proposed, given that the current default service approach sets rates based on a mix of direct procurement from the ISO-NE markets, and solicitation for the remaining load.

Response:

Here's an example, say the full default service rate is $0.088/kWh, the Base Energy Service Rate is $0.0800/kWh (mixing direct procurement and solicited fixed price supply) and the line loss factor is 3%, then the export credit rate would be $0.0800/kWh/1.03 = $0.0776/kWh, plus or minus any prior period true-up to actual supply costs. Although there would be a lagging true-up of market costs, most customer-generators are stable customers who generally do not switch suppliers, so most such true-ups would eventually flow directly to them. If the avoided transmission costs were $0.016, then the net compensation rate for exports by a large customer-generator would be $0.0776 + $0.016 = $0.0936.

The mix of direct procurement and solicitation for fixed pricing for portions of utility default service will require the prior period reconciliation of power supply costs to be applied to the utility default service export rate to properly reflect the value of those exports and result in just and reasonable rates.

At the time our testimony was developed and filed, almost all of utility default service was being procured through competitive solicitations that provided fixed monthly prices for all-requirements power for any and all load that showed up on utility default service. As such the risk of under- and over-collection of supply costs from customer migration should generally be borne by the all-requirements supplier. Presuming that all kWh billed to customers in the large customer group (grossed up for line losses) aligns with the kWh that the all-requirements supplier was paid for and settled in the ISO-NE market, then there should be little reason for under- or over-collection of supply costs in that group given the fact that the rate charged to customers changed on a monthly basis should be in alignment with the monthly rate paid to the supplier.

In the small customer group, where a single price was fixed for six months based on a forecasted monthly load weighted average price, some over- or under-collection would occur to the extent that the actual monthly load shape deviates from the forecast monthly load shape (the portion of total six-month load occurring in each month). The line loss adjusted Base Energy Service Rate was still a reasonable proxy for hedged average market costs that customer-generators displaces, which is to say, energy and capacity value produced or avoided in purchases from the ISO-NE market.

The Commission is now requiring utilities to forecast unhedged forward wholesale energy market and capacity costs. This will result in actual costs deviating from forecasted costs as the protection of a load following all-requirements contract is missing. Thus, to reflect that actual value produced or avoided by exports to the grid by customer-generators, the true-up to actual market costs should be part of the export compensation rate.

Furthermore, due to the way each utility implemented the Commission's market price proxy methodology, all proposed market proxy price rates under consideration at present or recently approved for the rate period beginning February 1, 2025 appear to be priced significantly below the average ISO-NE spot market cost to serve load observed over the last four years. This is primarily due to how each utility estimated the energy and capacity rate components of the market proxy price calculation. The Commission's prescribed methodology was to compute the market proxy price as the "average of (a) the four-year rolling weighted average of ISO-New England market prices in the New Hampshire load zone, and (b) the NYMEX future prices for the upcoming six-month energy service period". However, none of the utilities appear to have calculated the historic load-weighted cost of energy for default customers, which would be computed by multiplying hourly wholesale load against hourly LMPs observed in the NH load zone. Instead, each utility is basing their energy cost estimates upon simple averages of hourly LMPs. Because load and market prices are positivity correlated, i.e., market prices tend to rise in relation to customer load levels, assuming that the simple average of hourly prices will be reflective of the hourly load-weighted price will systemically underestimate the historic and projected cost to purchase energy to serve default supply customers on the ISO-NE market. Each utility's capacity price assumptions also appear to be similarly under-estimating the actual cost of capacity to serve default customers.

In part, this may be due to the evident misinterpretation of the figures published in ISO-New England's Monthly Wholesale Load Cost Reports. As explained in the report, the figures are based on what a hypothetical large wholesale customer using 1,000 kilowatts of energy in every hour of the month would have been charged in the real-time market. In other words, the "rates" in these reports are only representative of the cost to serve customer load in the ISO New England spot market for customers with perfectly flat load profiles. The rates therefore understate the cost of capacity for default service customers, who's average ICAP tags reflect system coincident peak hourly usage that is above their average hourly usage, and also understates the cost of energy to serve default service customers, because the cost to a customer with a flat load profile is mathematically equivalent to taking the simple average of hourly LMPs.

That is why the ISO-NE monthly reports contain a paragraph in the introduction, which is emphasized in bold font, stating that "*[m]any important assumptions have been made in the formulation of this analysis*" and directing readers that "*[t]he 'Overview and Assumptions'*

Appendix to this report is vital to understanding the information presented", which, in turn, explains that "*[t]he rates represent the costs associated with serving one megawatt hour (MWh) of wholesale electricity in the New England wholesale markets*" and warns readers that "*[b]ecause the data presented here are averages, it is virtually impossible to accurately compute an average customer bill from these data. The series may assist in spotting trends, differentiating between costs at times of the day or year, and showing zonal differences*." For additional context, refer to the section "*Report Content and Timing*" in the introduction of the reports, and then to sections titled "*Assumptions*" and "*Using the Component Costs*" in the appendix of the reports. (*See*, e.g., the most recent ISO-NE *Wholesale Load Cost Report November 2024*, at 3, 22, and 27.)

The ISO-NE Monthly Wholesale Load Cost Reports are online at:

https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/mthly-whl-load-cost-rpt

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Request:

16. Please provide a short and simple narrative on the advantages and disadvantages of moving from the energy component being the default service rate to the proposed "Base Energy Service Rate."

Response:

The advantages of moving from a full default service rate credit for exports to the grid by customer-generators to one built from the Base Energy Service Rate (by adjusting for line losses and prior period market cost true-ups are:

1. It would align the compensation provided from this rate component with the value produced (or costs avoided) by such exports, which can be characterized as including avoided energy, capacity, and ancillary costs from the ISO-NE market, plus a substantial portion of line losses between bulk generation on the transmission grid and retail meter.
2. Such exports would not be compensated for costs they do not help avoid, including RPS compliance costs for the consumption of electricity and utility costs to administer default energy service, which includes providing on-bill credits for customer-generator exports.
3. Shifting of costs for RPS compliance and utility administrative costs would not be shifted to other customers.
4. It would move utility tariffs for net metering closer to a market based approach consistent with New Hampshire statutory policy, including RSA 362-A:1[3] and RSA 374-F:1, II.[4]

The disadvantage of this approach are as follows:

1. There would be a one-time cost, likely modest, to modify utility billing systems to enable a different default service rate for exports than for consumption, as was done after the last net metering docket for distribution rates for small customer-generators.
2. There would be some modest changes and additional analysis work in presenting proposed utility default service rates for Commission review and approval.

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[3] RSA 362-A:1 states the goals of the chapter inclusive of net metering "should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3."
[4] RSA 374-F:1, II on the purpose of electric utility restructuring states that "Competitive markets should . . . provide electricity buyers and sellers with appropriate price signals . . .".

3. There could be an unjust reduction in overall compensation of customer-generators larger than 100 kW if not coupled with credit for avoided transmission costs.
4. A modest reduction in compensation for small customers-generators could cause some customer confusion and additional inquires to utility customer service. Such confusion could be largely mitigated by not including customer-generators in the residential rate classes in the proposed reduction toward the Base Energy Service Rate. This could be justified by the additional value that such small systems produce in avoided line losses compared to larger systems being very proximate to nearby load to be offset, the fact that some significant portion of small residential systems do not produce RECs but do help reduce the RPS compliance obligation of all suppliers without any other compensation by pursuant to the compliance reduction attributed to solar systems that do not produce RECs, and non-economic benefits that such systems produce, such as public health benefits from reduced air pollution from emissions as cited by the Conservation Law Foundation's brief in this case. .