NH Public Utilities Commission
Docket No. DE 22-060
Record Request – Set 1 – Response to Initial Filings

Received: April 24, 2024
Request Number: RR-C

Date of Response: July 26, 2024
Witness: CPCNH

Request:

Have any states factored locational marginal pricing into their net metering tariffs?

Response:

To the extent that this inquiry applies to the locational price at nodal points within the overall NH load zone, CPCNH would concur with the Responding Parties.

However, if the question refers to LMPs at the overall NH load zone level, meaning, in particular the hourly LMP for NH, then NH tariffs under the Commission's jurisdiction do factor in LMPs in compensating annual net exports under the NM 1.0 (standard net metering) provisions pursuant to the Puc 900 rules, specifically at Puc 903.02(o)(2):

> (2) The rates for avoided energy costs shall be based on the short-term avoided energy costs for the New Hampshire load zone in the wholesale electricity market administered by ISO New England, Inc., consisting of the hourly real time locational marginal price (LMP) of electricity plus generation-related ancillary service charges, all adjusted for the average line loss in New Hampshire between the wholesale metering point and the retail metering point;

CPCNH's witness in the docket, Clifton Below, served as a PUC Commissioner at the time[4] most of the language in Puc 903.02(o) and related provisions were developed. He served as the Commission's lead on drafting this language and taking it through the rulemaking approval process. He would be happy to provide additional context at the hearing if the Commissioners have further questions. This language was developed when all net metered compensation was detailed in statute, before the Commission was provided additional statutory discretion in 2016 to change the terms of net metering pursuant to RSA 362-A:9, XVI.[5]

Up until the enactment of Chapter 143, NH Laws of 2010 (HB 1353) there was no provision for compensation of surplus generation, and as a result, excess kWh could only be carried forward indefinitely until they were used up behind the meter (BTM). Then Commissioner Below was tasked by the PUC Chair with assisting the sponsor, Rep. Harvey, and the committee in its work sessions with drafting the proposed legislation and House Science, Technology & Energy (ST&E) committee amendment, as that was a normal practice in those days to help with such legislative requests, including the Commission taking a position on such legislation.

The bill, as introduced, was entitled "relative to group net metering;" however, as enacted, it did not actually create group net metering, which came later. It did amend RSA 362-A:9 to provide

[4] His term started in December of 2005 and ended in February of 2012.

[5] Originally enacted as chapter 31 NH laws of 2016, though with significant amendments since then, that law triggered DE 16-576 that resulted in the first update of net metering tariffs.

compensation for annual net surplus generation and expanded net metering eligibility from 100 kW to 1 MW, among other things. As introduced, the bill provided for surplus power exported to the grid in excess of BTM load to be credited at more than the federal Public Utility Regulatory Policies Act (PURPA) avoided cost rate for qualifying facilities (QFs). As introduced, PSNH opposed it.[6] PSNH argued that any monetary credit for surplus exports to the grid was legally limited to what QFs selling into the ISO-NE market would be compensated, basically the real time LMP (and perhaps avoided ancillary services and capacity costs). PSNH dropped that argument when they supported the settlement in DE 16-576, where they supported monetary credit for energy at 100% of their default service rate for monthly net exports, plus 100% of the volumetric (kWh) transmission rate for "small projects" (those up to 100 kW). The concept of treating net metered generation not participating in the ISO-NE market as "load reducers" relative to ISO-NE charges for generation, capacity, ancillary services, and transmission was not as clearly understood as it is today, where there can be considerably more value to be realized as a "load reducer" than selling through the ISO-NE markets. Also, FERC has not sought to assert control over net metering export compensation rates, leaving such matter to state jurisdiction where the generators are not participating in federal markets like that of ISO-NE.

Then Commissioner Below helped draft the House compromise to HB 1353,[7] which ended up being a complete repeal and replacement of the entire RSA 362-A:9 that resulted in the support of all stakeholders, including PSNH and renewable energy advocates, who testified in support of the bill as passed by the House[8] with this language:

> V. When a customer-generator's net energy usage is negative (more electricity is fed into the distribution system than is received) over a billing period, such surplus shall either:
>
> (a) Be credited to the customer-generator's account on an equivalent basis for use in subsequent billing cycles as a credit against the customer's net energy usage or bill in a manner consistent with either subparagraph IV(a) or IV(b), as applicable; or
>
> (b) Except as provided in paragraph VI, the customer-generator may elect to be paid or credited by the electric distribution utility for its excess generation at rates that are equal to the utility's avoided costs for energy and capacity to provide default service as determined by the commission consistent with the requirements of the Public Utilities Regulatory Policy Act of 1978 (PURPA). The commission shall determine reasonable conditions for such an election, including the frequency of payment and how often a customer-generator may choose this option versus the option in subparagraph (a).
>
> VI. Instead of the option in subparagraph V(b), an electric distribution utility providing default service to customer-generators may voluntarily elect, annually, on a generic basis, by notification to the commission, to purchase or credit such excess generation from customer-generators at a rate that is equal to the generation supply component of the applicable default service rate, provided that payment is issued at least as often as

[6] *See*, p. 19 of the House legislative history of 2010 HB 1353: https://gencourt.state.nh.us/BillHistory/SofS_Archives/2010/house/HB1353H.pdf .

[7] *See, for example, Id* at pp.46-54, three draft amendment alternatives originally drafted by then Commissioner Below.

[8] *See* page 44 of the Senate legislative history of 2010 HB 1353: https://gencourt.state.nh.us/BillHistory/SofS_Archives/2010/senate/HB1353S.pdf.

> whenever the value of such credit, in excess of amounts owed by the customer-generator, is greater than $50.

This bill was also where the different credit rates for up to 100 kW and > 100 kW up to 1 MW were first established with the expansion over 100 kW as part of the negotiated consensus amendment in the House:

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

NH Public Utilities Commission
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Record Request – Set 1 – Response to Initial Filings

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Request Number: RR-D

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Witness: CPCNH

Request:

In the New Hampshire VDER study, what percentage of the value generated accrues to the customer generator and what percentage flows to (non-customer generator) ratepayers?

Response: (applicable only to "load reducer" DG not participating in ISO-NE markets)

From VDER study update, D. Results Tables (Updated), D.1 Technology-Neutral Value Stack					
		Column C	Column D	Column E	Column F
Table 1: Average Annual Technology-Neutral Value Stack ($/kWh) (2024$)	2024	Default Service Rate Credit	Transmission Rate Credit	Distribution Rate Credit	Benefit to all ratepayers
Energy	0.073	0.073			
Transmission Charges	0.028		0.028		
Distribution Capacity	0.008			0.008	
Capacity	0.005	0.005			
Distribution Line Losses	0.003	0.003			
RPS*	0.003	0.003			
Transmission Line Losses	0.002		0.002		
Risk Premium	0.010	0.010			
Ancillary Services	0.003	0.003			
DRIPE	0.007				0.007
Distribution OPEX	0.002			0.002	
Utility Admin	0.000	0.000			
Environmental Externality	0.065				0.065
Total – Excluding Environmental	0.143	$ 0.097	$ 0.030	$ 0.010	$ 0.007
% of Total - Exc. Environmental**	101%	67.8%	21.0%	7.0%	4.9%
Total – Including Environmental	0.208	$ 0.097	$ 0.030	$ 0.010	$ 0.072
% of Total - Including Environmental**	100%	46.6%	14.4%	4.8%	34.6%
WITHOUT ENVIRONMENTAL EXTERNALITY BENEFIT					
Benefit to DG > 100 kW column C only		**67.8%**			
Benefit to DG up to 100 kW columns C-E		**95.8%**			
Benefit to ALL ratepayers, column F only		When T & D credits go to DG:			**4.9%**
Benefit to ALL ratepayers, columns D-F		When T & D credits don't go to DG:			**32.9%**
WITH ENVIRONMENTAL BENEFIT EXTERNALITY BENEFIT					
Benefit to DG > 100 kW column C only		**46.6%**			
Benefit to DG up to 100 kW columns C-E		**65.9%**			
Benefit to ALL ratepayers, column F only		When T & D credits go to DG:			**34.6%**
Benefit to ALL ratepayers, columns D-F		When T & D credits don't go to DG:			**53.8%**
*RPS benefits flow directly to DG that generates RECs, but also is a credit as part of full default service rate credit .					
** The sum of percentages don't quite equal 100% due to rounding.					

NH Public Utilities Commission
Docket No. DE 22-060
Record Request – Set 1 – Response to Initial Filings

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Request Number: RR-E

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Witness: CPCNH

Request:

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

Response:

CPCNH agrees with the first paragraph of the Responding Parties response. Another simple example of deliberate and acceptable cross-subsidization is with regard to cost-causation to serve customers in denser urban and town centers with lots of load per mile of distribution lines versus more rural areas where there are fewer customers and amount of load per mile of distribution poles and wires with higher corresponding maintenance costs including vegetation management and storm recovery/customer and kWh than in more dense areas, yet we don't differentiate based on density per mile of distribution line both for good practical and policy reasons.

In the last net metering docket, DE 16-576, CPCNH witness Below observed that as net metering started out and developed prior to 2016, the compensation and credits mechanisms were ***a <u>rough</u> justice***, legislatively determined, and that the development of alternative NM tariffs (NM 2.0) to be reviewed and approved by the PUC was an opportunity to make the rough justice somewhat more granular and accurate. Likewise this case is an opportunity to refine the fairness of net metering and minimize undue, or not reasonably necessary cost shifting or cross-subsidization that may be considered unjust and unreasonable, especially as time goes on.

CPCNH concurs with CENH's conclusion that if anything, overall, net metering customer-generators produce more benefits than they are currently compensated for and so are "subsidizing" non-net-metered customers. This is especially true for NM customer-generators >100 kW that function as load reducers because they are not ISO-NE market participants as discussed in CPCNH's direct testimony particularly at pp. 19-23 and rebuttal testimony at p. 9.

NH Public Utilities Commission
Docket No. DE 22-060
Record Request – Set 1 – Response to Initial Filings

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Request Number: RR-F

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Witness: CPCNH

Request:

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

Response:

As noted in the DOE and Responding Parties response to the request, there was only one study prior to the recent Dunsky VDER study, which was the New Hampshire Locational Value of Distributed Generation Study by Guidehouse, July 31, 2020 (LVDG study). That study strongly supports CPCNH's position that we need to start sending strong temporal price signals to DG production, and enable storage to be part of net metering, in order to realize the greatest value of DG and DS to avoid or defer potentially large capital investments to make up for capacity deficiencies in the grid.

The LVDG study also showed that the value of DG in avoiding distribution system investment costs is highly dependent on both location (i.e., whether it is on a part of the distribution system that has or may have capacity deficiencies in the foreseeable future) and on the production profile of the DG as to its coincidence with periods of peak demand when capacity deficiencies occur. The study focused "on significant distribution system capacity deficiencies to be addressed through planned or potential capital investments, such as replacements or upgrades of substations or circuits." (At p. iii.) The study compared the production profiles of various PV technologies, including fixed tilt at various orientations and single and dual axis trackers, as well as coupling storage with solar and hydroelectric DG and found (at p. 82) that:

- "The number of hours of capacity deficiency varies significantly by location, with some locations with fewer than 15 hours of deficiency per year, while other locations are capacity deficient for several thousand hours per year.
- "**Most locations have capacity deficiencies during late afternoon or early evening hours. Solar PV production profiles do not fully align with those hours of capacity deficiency. Solar PV paired with energy storage typically can produce electricity during most or all hours during which there are locational capacity deficiencies.**
- "Hydro production profiles typically align with hours of capacity deficiency, but with lower production during summer months as compared to winter months."

CPCNH would like to call attention particularly to Figures 47 through 50 on pp. 65-67 of the LVDG study that illustrate how single and dual axis trackers (especially in the winter for the later) have production profiles that can better match overall daytime load and times of peak demand, as excerpted on the next two pages.

Figure 47. Average Summer Production by Solar Array Configuration Type

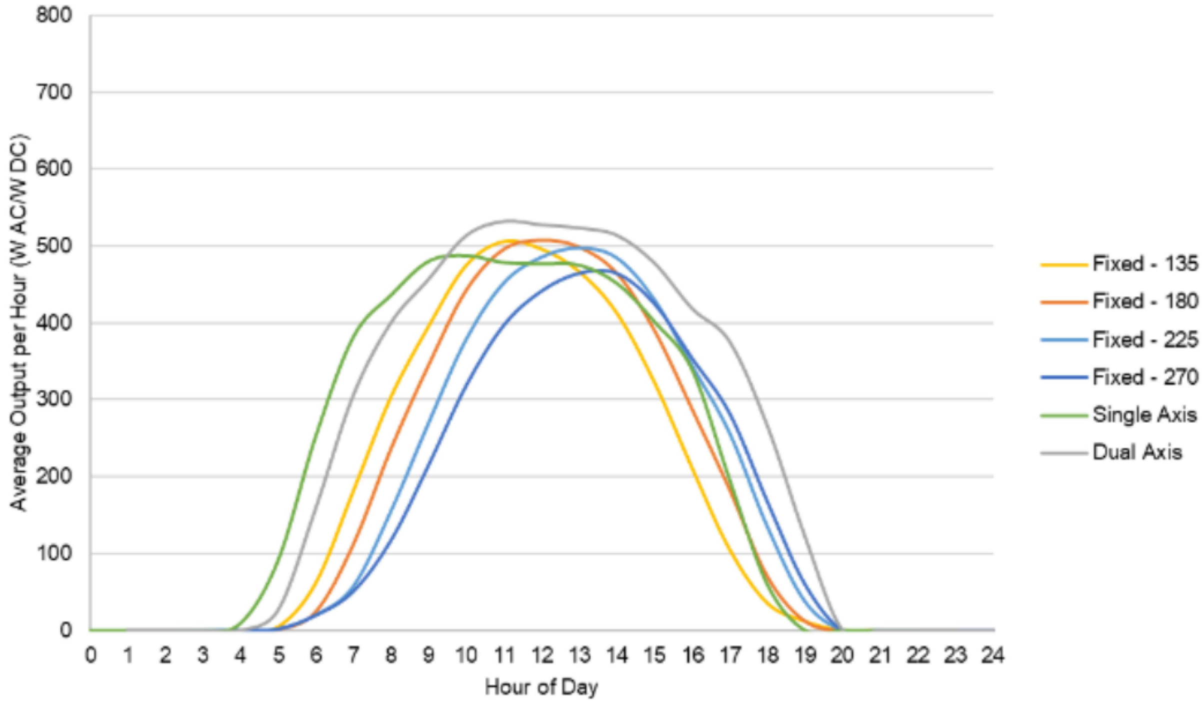
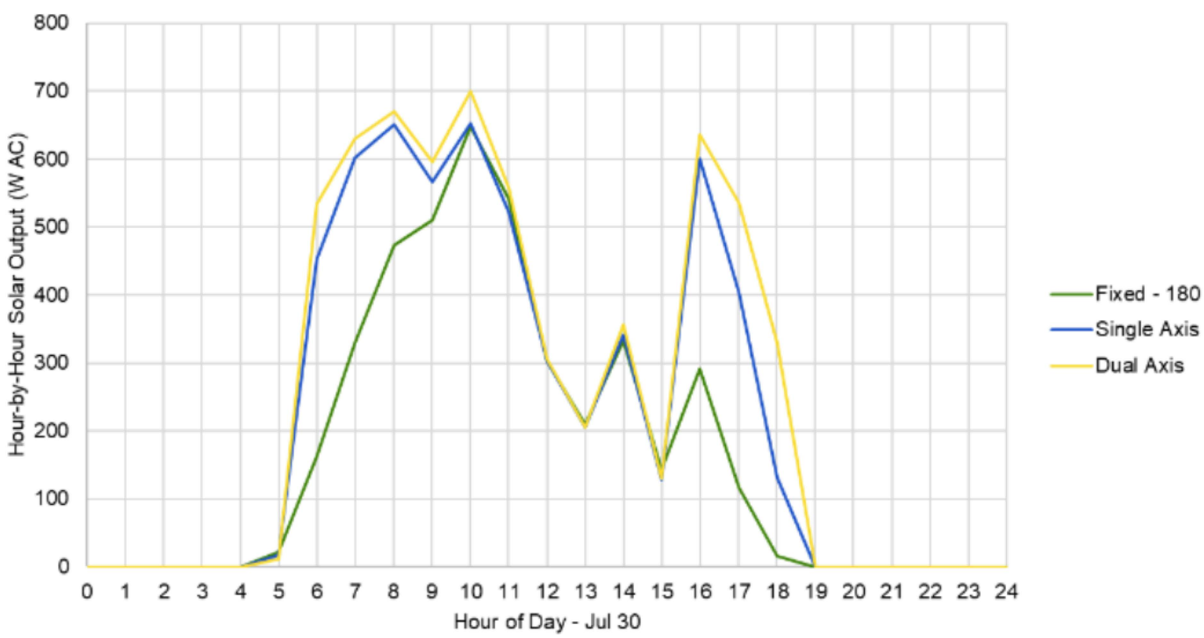


Figure 48. Peak Day Summer Production by Solar Array Configuration Type



Source: Guidehouse

Figure 49. Average Winter Production by Solar Array Configuration Type

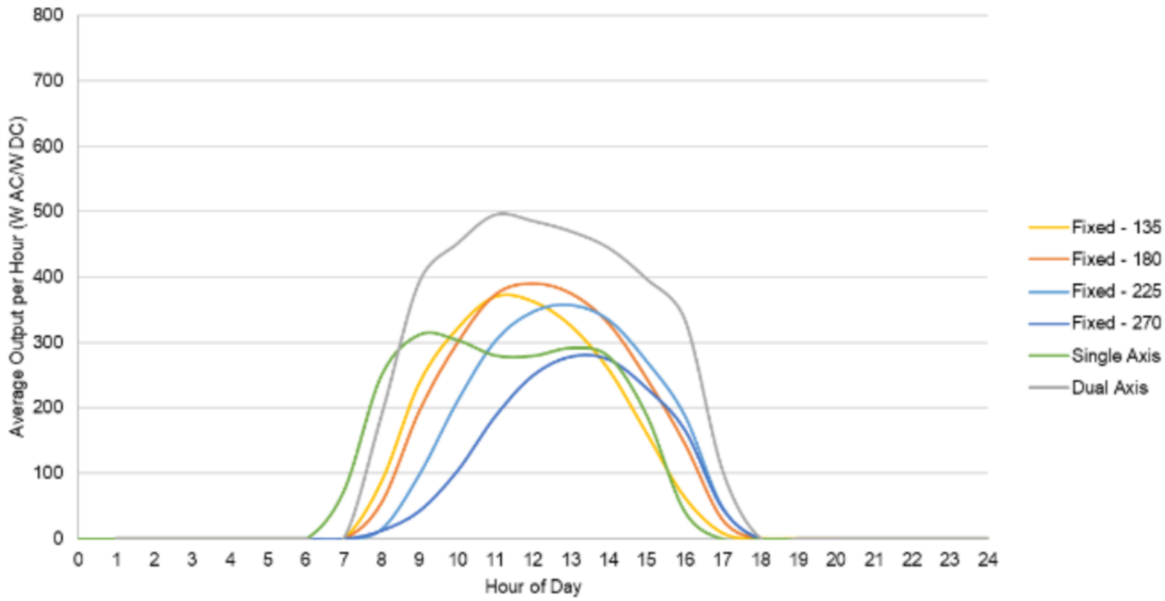
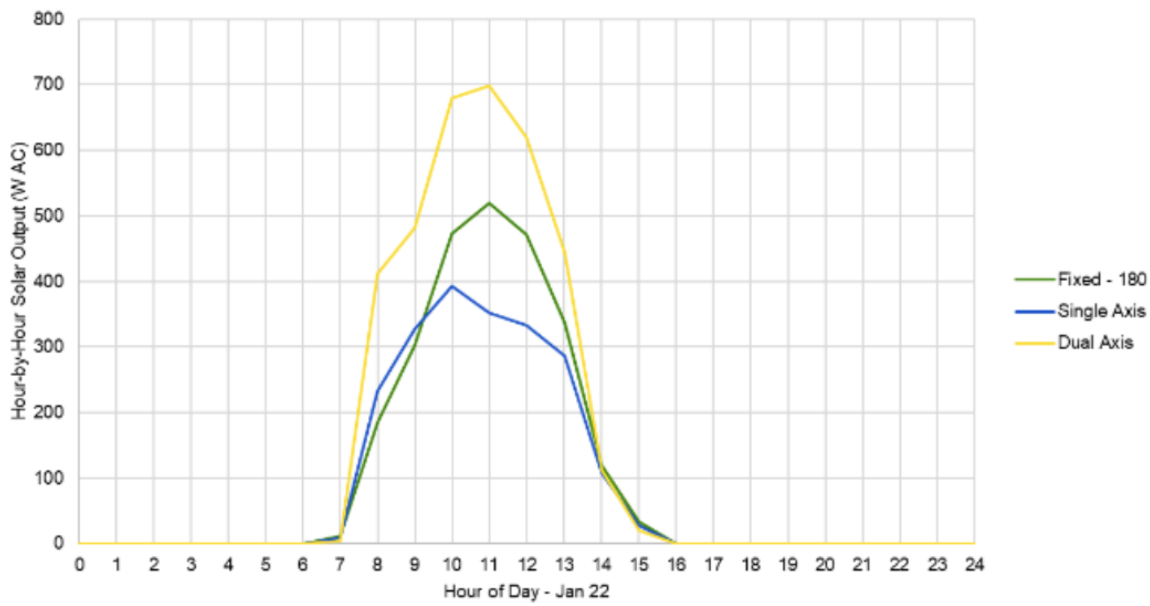


Figure 50. Peak Day Winter Production by Solar Array Configuration Type



Source: Guidehouse

As single and dual axis trackers typically require more capital investment than fixed tilt systems, there needs to be clear and accurate temporal price signals, such as the avoided cost value of reducing net load on the system coincident to monthly and annual system peaks, when transmission and generation capacity charges are incurred, in order to maximize cost effective benefits from DG and DG with storage.

NH Public Utilities Commission
Docket No. DE 22-060
Record Request – Set 1 – Response to Initial Filings

Received: April 24, 2024 | Date of Response: July 26, 2024
Request Number: RR-G | Witness: CPCNH

Request:

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

Response:

No, CPCNH disagrees with the Responding Parties. With the exception of CPCNH, all the other parties in this docket, via pre-filed testimony, assert that this is the appropriate rate. In their answer to this question, the Responding Parties assert that “there is no evidence that this level of compensation creates unjust cost shifting.” The DOE in their response states that the “default service rates are what the utilities will incur to purchase electricity supply for their customers.” CPCNH disagrees with both assertions.

At the outset though, we would note that for customer-generators > 100 kW, the utility default service rate is only compensation paid for exports to the grid, so while the full default service rate may be somewhat more that the avoided cost incurred to purchase supply for other customers, it is generally ***less than the value actually realized*** by such generation which does typically reduce transmission costs charged to ratepayers for which they receive no credit. The value realized in avoided transmission costs appears to generally be more than the over-compensation resulting from the use of the full default service rate as credit for exports to the grid, meaning non-net metered customers are realizing greater benefit.

RSA 374-A:9, XXIII provides that “the commission shall consider whether and when further changes should be made to the net metering tariff structure approved in Order No. 26,029 issued on June 23, 2017, applicable to” new customer-generators > 1 MW which **consideration “shall include but not be limited to whether or not the cost of compliance with the electric renewable portfolio standard, RSA 362-F, inclusive of prior period reconciliations, should be excluded from the monetary credit for exports to the grid**, as well as whether or not the monetary credit should include compensation for services and value currently not compensated such as avoided transmission, distribution, and capacity costs and other grid services.” [Emphasis added.]

In CPCNH’s direct testimony starting at page 23, line 21, witness Below explains why inclusion of RPS compliance costs for the consumption of electricity, including prior period reconciliation, should be excluded from the credit given to exports to the grid going forward as part of NM 3.0. Evidence of this unjust cost shifting is provided in its direct testimony on page 24, lines 5-28 and again in the Rebuttal Testimony of Clifton C. Below at pp. 4-6.

DOE's assertion that the full default service rate is what the utilities will incur to purchase electricity is inaccurate. The "Base Large C&I [or Small Customer] Energy Service Rate" in Eversource and Liberty nomenclature is what the utility pays to purchase electricity supply, inclusive of generation capacity costs. The difference between the full default service rate and the base rate includes the cost of RPS compliance for consumed electricity, including prior period over- or under-collection, plus utility administrative and general costs of administering default service, which includes working capital costs for default service and bad debt expense, and broadly, prior period under- and over-collection, none of which is provided by the supplier of electricity or net metered generation.

Indeed, this is exactly the rate that CPCNH has proposed the compensation rate for exports to the grid in NM 3.0 be reduced to, thereby avoiding undue and unjust cost shifting of RPS compliance costs and G&A expenses. *See* Direct Testimony of Mr. Below at pp. 25-27. Both RPS compliance and G&A costs are incurred for the benefit of NM customer-generators in months when they are net consumers of electricity, as well for as members of group net metering arrangements, so it would be fair and just if the credit for such was excluded from their credit rate for exports to the grid. The particular irony here under NM 2.0 is that a NM customer-generator can generate and sell RECs for their entire production (both exports to the grid and for BTM consumption); however, when it comes to their own net consumption, or that of group members, which incurs an RPS compliance obligation, they pay nothing for it up to the amount of kWh exported to the grid for which they receive compensation. Thus, the cost of their RPS compliance, up to the amount of exports to the grid in a different time or location, is unduly, and without regard to cost causation, shifted to non-NM customers.

In context though, it is important to note that while compensating for exports at the full default service rate is in and of itself over-compensation for this rate component, for customer-generators > 100kW, ***it still represents overall under-compensation for value produced***, because there is no credit for actual avoided transmission charges, which based on the evidence presented in Mr. Below's testimony, is typically more than the difference between the full default service rate and the base default service rate.

Further, there is some argument that unlike larger systems, many smaller systems under 100 kW, especially residential systems, do not produce RECs, though they could with a REC production meter. Nonetheless, pursuant to RSA 362-F:6, II-a, in a process known as "REC sweeping" the DOE annually estimates the amount of PV production from NH systems that do not produce RECs, allocates such REC equivalencies to all suppliers on a proportionate basis (according to total load share) to use in satisfying their RPS compliance obligation. Provision of credits at the full default service rate, in excess of the base default service rate that aligns with the avoided energy cost value, can thus be seen as a way to compensate such customer-generators for the value of the REC-equivalent sweeping for which they do not otherwise receive compensation.

This argument regarding compensation of smaller customer-generators was made by the Joint Utilities in a data request to CPCNH, which CPCNH will mark as an exhibit for introduction during the examination of CPCNH witness Below. The Joint Utilities also briefly noted this argument in their rebuttal testimony at p. 17, lines 12-22, though not specific to generation < 100 kW.

CPCNH concurs with the Responding Parties that smaller DG does tend to offset load that is quite close by, minimizing line losses and use of the distribution system while larger systems will offset both near and more distant loads and make greater use of the distribution system for such power flows with more resulting line loss than smaller systems.[9]

[9] *See, for example*, in DE 22-073 the UES Testimony of Jacob S. Dusling at p. 20, starting at line 14: "…each component of the utility distribution system contributes to electricity line losses and the amount of losses depends on the distance from the source to the load. Generally speaking, the longer the distance over which electricity is transmitted, the more electricity is lost. Output from the [Project] will be injected directly into the electric distribution system and will offset the amount of electricity that must be delivered to that point on the electric distribution system, marginally reducing distribution system losses."

NH Public Utilities Commission
Docket No. DE 22-060
Record Request – Set 1 – Response to Initial Filings

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Request Number: RR-H
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Witness: CPCNH

Request:

How does the avoided cost analysis in the VDER study support each party's position on the appropriate compensation mechanism in the net metering tariff?

Response:

CPCNH's understanding is somewhat different than the Responding Parties that the study merely "illustrates the potential sources of value that [DERs] may provide to the electric power system as a whole." The VDER study strongly supports key CPCNH positions:

It clearly shows that a large portion of the value of DERs is in the avoidance of transmission costs when DERs function as load reducers relative to the ISO-NE transmission grid and load settlement systems. DERs only function as load reducers when they are not registered with ISO-NE as "Generators" participating in those federal markets. This is noted in CPCNH's direct testimony staring at p. 17, line 26.

The study also showed how system design choices affect the potential production profiles and value of DERs, where systems that generate more power during periods of peak demand (typically later afternoon and early evening) produce more value than fixed tilt systems facing south, that dominate current ground mount installations. This is discussed in CPCNH's direct testimony starting on p. 19 at line 2 to some extent. Also of note are these observations in the VDER study:

- The avoided cost value that net-metered DERs provide to the electricity system is assessed by considering DER production profiles in combination with the hourly value stack, as described in the DER Avoided Cost Value section above. [p. 25]
- Throughout the study period, residential west-facing solar PV generates 5%-10% more avoided cost value than residential south-facing solar PV.38 Although south-facing systems have greater production overall, west-facing systems generate energy later in the day, increasing the portion of generated energy that is coincident with ISO-NE and New Hampshire-specific peak hours. This allows west-facing systems to generate greater value for those avoided cost categories that are driven by peak demand. Customer generators in New Hampshire are currently incentivized to maximize solar production by installing south facing systems, given that those systems produce a greater volume of electricity overall. [pp. 26-27]
- West-facing commercial solar PV systems produce 6%-10% more value than south-facing commercial solar PV systems, again due to their production having greater coincidence with evening system peaks. [p. 28]

- In any given year, residential solar PV systems paired with storage generate between 14% and 82% greater base avoided cost value than solar-only systems; commercial solar PV systems paired with storage generate 12% to 70% greater base avoided cost value.47 The battery storage system is assumed to be charged with energy generated by the solar array during off-peak times when avoided costs are low and solar generation is high (i.e., HE11 to HE14). The storage system is assumed to discharge during peak periods in the early evening (HE18 to HE21 in Winter and HE17 to HE20 in Summer) when solar production is lower and avoided cost values are higher. This timing of battery charging, and discharging provides considerable additional benefits for many avoided cost categories, including transmission charges, energy, line losses, and DRIPE. [p. 33]
- Unlike solar-only systems, the total avoided cost value for solar paired with storage systems increases over time. These increases are primarily a result of transmission charge avoided costs, which are assumed to increase in value over the study period. In 2021, transmission charges are the largest avoided cost value for both system types (30% of the base value stack). By 2035 the value of transmission charges is projected to make up 55% of base avoided cost values for residential systems and 53% for commercial systems while other avoided costs, including energy, decline over time. [p. 33]

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Record Request – Set 1 – Response to Initial Filings

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Witness: CPCNH

Request:

Why would the net metering tariff be different for sub 100kW generators, 100kW-1MW generators, and 1-5MW generators?

Response:

CPCNH can provide additional background to that provided by the Responding Parties and DOE in the initial filings in response to the Commission record requests.

Please see CPCNH's response to Request No. RR-C, page 5, where it explains that the split in compensation rates between generators up to 100kW and >100 kW first occurred in conjunction the expansion of eligibility for net metering beyond 100 kW up to 1 MW pursuant to Chapter 143, NH Laws of 2010 (HB 1353).

The distinction between up to 1 MW and 1 to 5 MW came about when net metering eligibility was first expanded through the municipal host construct to extend up to <5MW by adding to definitions in the LEEPA statute pursuant to Chapter 229, NH Laws of 2021 (HB 315).

The requirement in RSA 362-A:9, XVI(b) and (c) that tariffs applicable to > 100 kW up to 1 MW also apply to customer-generators > 1 MW until new tariffs are approved [in this docket] was actually enacted as part of a different bill, Chapter 228, NH Laws of 2021 (SB 91), Part II, §2. This law allows but does not require the Commission to approve rates or tariffs that might be different for customer-generators >1 MW than for those that are up to 1 MW.

Both of the two 2021 pieces of legislation came out of complex negotiations and compromises by legislators from both parties and chambers, along with utilities, and other stakeholders.

One reason to potentially treat customer-generators > 1 MW differently is because at that scale the customer-generator will have an interval meter where the actual value of exports to the grid at hours of system peaks (monthly for transmission costs, annually for capacity) can be readily calculated. Unfortunately, in Eversource's service territory, most net metered generation > 100 kW and up to 1 MW does not have interval meters, nor any option for such, so it is more difficult to quantify actual value. In addition, there are relatively few of these size generators at present and relatively few are making it through the interconnection queue, so this it is a small enough group, with a significant potential impact on cost shifting, that compensation for grid exports can be based on actual meter data and "manually" calculated if necessary, although it would be calculated like a demand charge (but a as demand credit at monthly and annual hours of coincident peak demand).

As witnesses testified to in DE 22-073, Unitil's single axis tracker project, New Hampshire has many opportunities for "load reducer" projects in the 1-5 MW range. Due to economies of scale the optimal sizing of many projects will tend toward the higher end of the generation capacity. Also, with the utility being able to count a value stack that includes avoided energy, generation capacity, ***and transmission charges***, the latter two of which provide strong temporal price signals, the design they chose was a single axis tracker that produce more power in the late afternoon when the coincident peaks occur for capacity and transmission charges, than a fixed orientation ground mount array that are typically designed to be oriented due south with maximum production around solar noon.[10] With temporal price signals (i.e., with credit for actual avoided capacity and transmission charges) that should be readily implemented for projects with hourly interval metering, which should include all projects > 1 MW, but not necessarily under that size in Eversource territory, NH would see better investments resulting in less fixed orientation systems without storage, and more with storage (when permitted), as well as single and dual axis trackers with or without storage, all of which potentially produce more actual value per kWh than fixed orientation systems that result from valuing all kWh equally regardless of time produced.

The municipal host construct remains the only current opportunity for community-scale projects (between 1 to 5 MW) other than pursuant to RSA 365-A:2, 2a, and 2b (which is as yet untested), RSA 374-G (by utilities), or registering and participating in the ISO-NE market, in which case the load reducer values are eliminated.

There are also various reasons for treating smaller systems up to 100 kW differently than > 100 kW as explained by Responding Parties that CPCNH generally concurs with although the 100 kW breakpoint for differential treatment, like any distinct change in treatment due to size, such as C&I rate classes, is somewhat arbitrary and there could be arguments for different break points of, say, 60 to 200 kW for various purposes.

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[10] *See, for example,* in DE 22-073 the UES Testimony of Jacob S. Dusling at p. 16, starting at line 18: "Although single-axis tracker technology is typically more expensive than a fixed-tilt approach, single-axis trackers allow for greater energy production because the solar panels rotate from east to west on a fixed axis throughout the day to track the movement of the sun. Based on a review of the cost and performance tradeoffs of these two technologies, [UES] determined that the single-axis tracker technology is a better approach because the increase in benefits exceeds the added cost."