THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISISON

DE 22-060

ELECTRIC DISTRIBUTION UTILITIES

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

Community Power Coalition of New Hampshire Post-Hearing Brief

Table of Contents

I. Introduction

a. The Commission's Mandatory Statutory Duty is to Continue to Develop and Periodically Review New Alternative Net Metering Tariffs to Ensure the Compensation Structure is Just and Reasonable and Aligned with the Public Interest

In this docket, the Commission exercises its important statutory duty under the 2021 version of RSA 362-A:9, XVI(a) that the "commission, through an adjudicative proceeding, *shall continue to develop* and periodically review new alternative net metering tariffs . . ." (Emphasis added.) Everything about this legal duty — the use of the mandatory word, "shall," the meaning of the phrase "continue to develop," the historical context of the amendments that create the current version of the statute, and a holistic review of the entire statute — points towards the Commission's duty being to be evolve net metering ("NM") in such a way that it accounts for market and technological trends while ensuring that the compensation structure is just and reasonable and aligned with the public interest..

First, the Commission's duty arises from the specific words used in the law. In giving meaning to the law, individual words cannot be read into or out of any given law.[1] Accordingly, the word choice of "shall" as opposed to "may" in the context of "continue to develop," must be interpreted to have been a purposeful choice to create a mandatory duty to "continue to develop" as opposed to setting forth a discretionary choice of whether to continue to develop or not. It is well-settled that the use of the word "shall" in a phrase such as this establishes a mandatory, non-discretionary duty on the part of the implementing agency.[2]

Similarly, the words "continue" and "develop" must be considered to have been purposefully

[1] *In the Matter of Carter*, 2024 N.H. 30, *P7 (2024); *Doe v. Attorney General*, 175 N.H. 349, 352 (2022); *Rogers v. Rogers*, 171 N.H. 738, 745 (2019); *Roberts v. Town of Windham*, 165 N.H. 186, 190 (2013).
[2] *Horton v. Clemens*, 173 N.H. 480, 485 (2020); *Bennet v. Town of Hampstead*, 157 N.H. 477, 484 (2008) ("The general rule of statutory construction is that the word 'may' makes enforcement of a statute permissive, and that the word 'shall' requires mandatory enforcement."); *In the Matter of Liquidation of Home Ins. Co.*, 157 N.H. 543, 554 (2008) ("We have previously concluded that the word 'shall' is 'unambiguous. It is mandatory, not permissive, language.'" Quoting *Theresa S. v. Sup't v. YDC*, 126 N.H. 53, 55 (1985)).

used in their plain English meanings.[3] "Continue" has common definitions, including, to maintain without interruption; endure; keep up, maintain; to keep going or add to.[4] "Develop" also has various definitions, including, to cause to evolve or unfold gradually; to lead or conduct (something) through a succession of states or changes each of which is preparatory for the next; to expand by a process of growth,[5] and to grow into a more mature or advanced state.[6] Neither of these two words alone, and especially not together as the statutory phrase "continue to develop," could mean maintain a form of the status quo when demonstrable refinements and improvements can be made that are just and reasonable and align with the public interest. By its plain English meaning, the law means the Commission must keep going to evolve and refine NM.

Second, the history from which the current 2021 version of the statute arises demonstrates a clear expectation of succession and growth of NM. The 2021 statute updated the 2016[7] version that first required the Commission to develop new alternative NM tariffs, which it did in Docket No. DE 16-576, with tariffs going into effect in 2017. Seeing that impact, four years later, lawmakers enacted the current, 2021 version mandating the Commission to "continue to develop" new alternative NM tariffs — indicating a clear direction to the Commission to further develop and refine NM beyond what was then, and still remains, the status quo of NM 2.0 ("NM 2.0").

For the first time in its history of continued development of alternative NM tariffs, the Commission must now consider ("shall consider") this new factor of:

> balancing the interests of customer-generators with those of electric utility ratepayers by maximizing any net benefits while minimizing any negative cost shifts from customer-generators

[3] *In the Matter of Carter*, 2024 N.H. at *P7; *Doe*, 175 N.H. at 352; *State v. Beattie*, 173 N.H. 716, 720 (2020); *see also* RSA 21:2 ("[w]ords and phrases shall be construed according to the common and approved usage of the language").
[4] Merriam-Webster Dictionary, available at, https://www.merriam-webster.com/dictionary/continue last visited September 16, 2024.
[5] Merriam-Webster Dictionary, available at, https://www.merriam-webster.com/dictionary/*develop* last visited September 16, 2024.
[6] Dictionary.com, available at, https://www.dictionary.com/browse/develop, last visited September 28, 2024.
[7] Chapter 31:4, NH Laws of 2016 (HB1116).

to other customers and from other customers to customer-generators,

in addition to the eight factors that existed in the 2016 version of RSA 362-A:9, XVI that the Commission found supported its approval of the creation of NM 2.0 as detailed in Order No. 26,069 at 68-71.

This use of the word "shall" here is slightly different than the use discussed in the previous section. It also sets forth a mandatory duty, as is well-settled in New Hampshire (NH) law. However, the mandatory duty it imposes on the Commission is that the Commission must "consider" those specific factors. In other words, the Commission has no discretion whether or not to consider those factors; it must consider them. But the Commission does have discretion with respect to what action or inaction it decides to take as a result of its consideration of each of the factors. Yet, the Commission has two important guardrails that make its exercise of discretion in consideration of these factors not unfettered. First, the Commission's decision must always be supported by the law and the facts in the record. Second, it could strain legislative intent past the point of legality if it exercised its discretion in such a way as to decide not to act with respect to any of the factors. As noted, the current, 2021[8] version arises out of a continuing sequence in the development of alternative NM tariffs in N H that fortifies the Commission's legal duty set forth in statute to continue to develop and evolve NM.

Bolstering that 2021 current law to evolve NM, this same 2021 legislation also added subparagraphs (b) and (c) to RSA 362-A:9, XVI, which provides that the provisions of Order No. 26,029 for large customer-generators (> 100 kilowatts to 1 megawatt) shall apply to customer-generators (CGs) > 1 megawatt (MW) until the Commission adopts alternative NM tariffs that "expressly apply" to CGs > 1 MW. The law also provides those operating under prior tariffs with the voluntary option to switch to such new tariffs, with the exception that they cannot switch back after they have opted into the new alternative tariff. This law, along with the subsequent 2022 enactment of RSA 362-A:9, XXIII[9], expresses an expectation that the Commission will further develop and refine NM terms, particularly for these large

[8] Chapter 228, Part II:2, NH Laws of 2021 (SB 91).
[9] Chapter 308:1, NH Laws of 2022.

NM CGs > 1 MW, with specific additional considerations that are required for such CGs.[10]

b. How Exports to the Grid Should be Accounted for in this Docket

Turning to one additional, introductory question, 2021 SB 91, Part II, Sec. 3 added paragraph XXI to RSA 362-A:9 that reads, in part:

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

Although the Commission did not call out this question in its 9/20/22 Order of Notice in this docket, the question directly pertains to a number of the statutorily required considerations in this docket, including "maximizing any net benefits while minimizing any negative cost shifts," and whether there should be compensation for "avoided transmission" and "capacity costs" for CGs > 1 MW. Parties raised the issue during the proceeding without objection,[11] though the Settlement Agreement proposed by some parties does not address this particular question. This brief explains why the law and evidence support an affirmative answer to the question: "whether or not exports to the grid by customer-generators taking default service should be accounted for as reduction to what would otherwise be the wholesale load obligation of the load serving entity providing default service absent such exports to the grid."

II. Coalition's Position: Approve Settlement Agreement with Conditions

The proposed settlement agreement largely requests continuation of the status quo with only slight modifications ("NM 2.1"). NM 2.1 postpones consideration of further development of new alternative NM tariffs until after a loosely defined data collection effort and a new docket is opened. Additionally, NM 2.1 would:

1. extend those terms previously applicable to large CGs up to 1 MW to every CG > 100 kilowatts

[10] RSA 362-A:9, XXIII.
[11] Transcript of January 5, 2023 Pre-Hearing Conference at 26:6–27:18 (Tr.); Hearing Exhibit 3 at 23–27; Tr. Hearing August 22, 2024 20:12–122:10, 232:8–et seq.

and less than five megawatts; and

2. continue all of the existing terms and conditions for NM, with the following two exceptions:
    a. a forward rolling legacy period of twenty years during which the CG could stay on a NM tariff with the same compensation structure as they start on, based on the year they start net metering; and
    b. a new application fee structure to defray the utility cost of processing NM interconnection applications.

The N H Department of Energy (DOE) varies from the proposed settlement agreement only in that it opposes extending the existing legacy or "grandfathered" period that currently extends to only 12/31/2040, and it further supports more immediate transition of NM customers to time-of-use rates where they are otherwise available (e.g., Unitil & Liberty, in their respective small customer group).[12] DOE, like the Coalition, also supports the proposed interconnection application and initial fee structure as described in the proposed settlement agreement.[13]

For the Commission's convenience, the Coalition has set forth its requested actions below in the form of proposed ordering clauses, followed by the legal analysis and evidentiary basis for why these actions support the Commission's obligations to set just and reasonable rates and meet other legal obligations, including the factors the Commission must consider as outlined above. Collectively, the Coalition's requested actions are referred to as "NM 3.0."

III. Approve Settlement with Conditions

ORDERED, that the Settlement Agreement as EXHIBIT 1 is approved, with updated tariffs to be effective for new customer-generators that begin net metering ninety days after the Order date, subject to the conditions set forth below in these

[12] *See* Tr. Hearing August 22, 2024 at 28:10–22:16, 35:10–36:6.
[13] *See* Tr. Hearing August 22, 2024 at 33:17–34:13, 146:10–16.

ordering clauses [or previously detailed in the Order]; and it is . . .

Continuation of the status quo until modifications to metering, business processes, and billing can be implemented is reasonable on the face of it, for practical reasons. The Coalition's proposed evolution of NM terms and tariffs will maximize net benefits and minimize undue cost shifting, compared with continuing the status quo, and will move NM compensation to a more market-driven approach based on actual performance of CGs in avoiding costs that are consistent with statutory mandates which prefer customer choice in the provisioning of NM.[14] For CGs that begin NM after the effective date of NM 3.0 terms and tariffs, they will initially receive the same compensation as NM 2.0; however, as the changes detailed below are implemented, the compensation under NM 3.0 will evolve. Because this evolution will provide compensation that is more closely aligned with actual avoided cost value that the NM CGs can deliver, we will avoid unjust and unreasonable cost shifting and thus will mitigate concerns of the DOE and the Commissioners that a 20-year legacy (i.e., grandfathering) period that new CGs can lock into will result in unreasonable rates beyond 2040.[15] The Coalition's testimony supports that of the Settling Parties that a 20-year legacy period in which NM 3.0 terms and tariffs are intended to retain the same structure is appropriate and necessary to support the state policy goals articulated in RSA 362-A:1 and more recent statutory statements of purposes.[16]

IV. Accounting for Exports to the Grid

FURTHER ORDERED, that the Joint Utilities shall, in collaboration with DOE, New Hampshire Office of Consumer Advocate (OCA) and other interested parties, convene a stakeholder group within one month of the date of this Order to develop parameters for modernized load settlement that allows exports to the grid by CGs that

[14] *See* RSA 362-A:1; Chapter 31:1 NH Laws of 2026; Chapter 226:1 NH Laws of 2017 and Chapter 328:2, NH Laws of 2022. All of these are available for convenient review in Hearing Exhibit 13 at 40–41.
[15] *See* Tr. Hearing August 22, 2024 at 115:15–119:23.
[16] See *supra* notes 14–15; *see also* Hearing Exhibit 1 at 9:14–26, 11–12. *See also* Hearing Exhibit 2 at 7:12–et seq.; and Tr. Hearing August 22, 2024 at 115:13–116:12.

function as load reducers and net metered CG load shapes to be incorporated into the load settlement for each load serving entity provisioning default service[17] such that exports to the grid by CGs served by each such load serving entity are accounted for as a reduction to their wholesale load obligation compared with what it would be absent such exports to the grid; and it is

FURTHER ORDERED, that the Joint Utilities shall file in this docket within three months of the date of this Order a report on proposed parameters for modernized load settlement and supporting changes to EDI/EBT processes and tariff language, based on the stakeholder process; and shall file in this docket within six months, cost, time, and process estimates for implementing such load settlement updates, including proposed line loss adjustments and an option for joint procurement of a sole vendor to provide settlement on a contract basis for electric utilities under Commission jurisdiction; and it is

FURTHER ORDERED, that other Parties to the above-referenced docket may also file comments and proposals simultaneously with or within ten business days following the Joint Utilities filing; and it is

FURTHER ORDERED, that subsequent to such filings the Commission will issue a supplemental order of notice for any additional process needed to determine appropriate line loss factors, if any, as well as how and when to implement changes to load settlement and to support EDI/EBT processes, including provisions for recovery of utility costs to implement such changes; and it is . . .

This foundational modernization of load settlement is key to dramatically reducing cost shifting

[17] Pursuant to RSA 374-F:2, I-a "municipal or county aggregators under RSA 53-E" are providers of "default service," along with electric distribution utilities, so this applies to both equally.

between net-metered and non-net-metered customers "while ensuring costs and benefits are fairly and transparently allocated among all customers."[18] The N H Value of Distributed Energy Resources prepared by Dunsky Energy + Climate Advisors, including the original 2022 report, 2023 addendum, and updated materials ("VDER Study") shows that the single largest benefit of NM is avoided energy costs, including related avoided capacity costs and line losses, because local NM generation actually reduces the amount of power purchased from the ISO-NE markets (for the vast majority of NM systems functioning as load reducers[19]). Yet this benefit is obscured in load settlement as part of "unaccounted for energy" which also includes line losses, differences between estimated load shapes and actual load shapes, and other unaccounted for variables.[20] Through the "residual calculation," this unaccounted for energy, including CG exports to the grid, is inappropriately socialized across all suppliers instead of accurately apportioned based on each supplier's fair share of CG exports to the grid. This results in the costs and benefits of NM CG exports to the grid not being accurately assigned to those who are actually creating those costs and benefits. This contradicts RSA 362-A:9, XVI (a) to "avoid unjust and unreasonable cost shifting" as part of the Commission's mandatory duty to "develop and periodically review net alternative net metering tariffs." [21]

By accounting for NM exports to the grid as an offset to what would otherwise be the default service supplier's ISO-NE wholesale load obligation (including market pass through purchases), the cost of supplying default service would decrease in proportion to the amount of such NM exports. If, going forward, the compensation for kilowatt hours exported to the grid are reduced to the Base Energy Service Rate, then the entire default service generation supply credit would be recoverable from default service customers at the market set rate per kilowatt hour, thus eliminating costs shifting related to energy supply

[18] Chapter 31:1 NH Laws of 2016, part of the purpose statement of 2016 HB 1116.
[19] *See* Hearing Exhibit 13 at 14:1–7, 16:13–18 (as of data response date, only 51 CGs out of some 16,400 CGs are ISO-NE market participants.
[20] *See* Tr. Hearing August 22, 2024 at 232:6–12.
[21] *See* Hearing Exhibit 13 at 15:5–16:2.

credits.[22] Eventually layering on time-of-use supply rates would begin to time differentiate the value of that production.

Modernizing load settlement is also required to meet long-standing statutory goals for market competition and customer choice. The goals of RSA 362-A, including the provisions for NM, "should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3." In turn, those provide for customer choice of competitive suppliers for all retail customers, an intent lawmakers codified in the same 1996 legislation that first created NM in N H,[23] was reaffirmed as part of 2016 law-making,[24] and, as noted, remains part of current law.

RSA 362-A:9, II and now includes Community Power Aggregations (CPAs) under RSA 53-E along with Competitive Electricity Power Suppliers (CEPS) as having the right to serve NM customers and determine the prices at which they agree to supply and credit or purchase output exported to the grid by such CGs "as an offset to supply." In 2020, this intent was further reinforced by the requirement that "[s]uch 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." RSA 362-A:9, II. As noted in the above analysis, use of the word "shall" in a context like this, creates a mandatory, non-discretionary duty on the Commission's part.[25] Accordingly, any order, rule, or argument that treats this statutory language as anything less than a mandatory, affirmative duty on the Commission's part lacks merit. Maximally modernizing load settlement simultaneously amounts to taking the largest step possible to minimize undue cost shifting and making much more transparent the costs and benefits of NM and therefore, satisfying key statutory

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[22] *See* Hearing Exhibit 13 at 27:1–18.
[23] *See* original provision in RSA 362-A:9, III ("Electricity Suppliers may voluntarily determine the terms, conditions, and prices under which they will agree to provide generation supply and purchase net generation output from eligible customer-generators").
[24] *See also* Chapter 31:1 NH Laws of 2016 (HB 1116) (also provided in Hearing Exhibit 13 at 40–41).
[25] *Horton*, 173 N.H. at 485; *In the Matter of Liquidation of Home Ins. Co.*, 157 N.H. at 553-54 (2008); *City of Rochester v. Corpening*, 153 N.H. 571, 574 (2006). *See also* RSA 21:2 ("Words and phrases shall be construed according to the common and approved usage of the language").

considerations and purposes.[26]

Giving only utility default service providers the ability to socialize all the costs of compensation to NM CGs, such as through a Stranded Cost Recovery Charge or some other non-bypassable delivery charge, undermines and defeats the customer choice through market competition concepts stemming from laws such as RSA 374-F:3. When CPAs and CEPS cannot do the same, and can only recover any such compensation from a smaller subset of their customers who are also paying for NM costs by utility default service CGs, it institutionalizes an unfair structural advantage resulting in unfair and discriminatory treatment of customers served by CPAs and CEPS which contradicts RSA 341-F:3. This situation cannot be justified because "CPCNH already receives the socialized share of the residual [calculation in the load settlement process]."[27] The Commission has a duty under RSA 374-F:3, IV to "take necessary measures to ensure that *no supplier* has an unfair advantage in offering and pricing such services." (Emphasis added.) The Commission has previously noted: "our delegated mandate is to promote competition not to perpetuate monopolies.[28] In that Order, the Commission recounted the law of N H as our Supreme Court has stated it:

> *.[L]egislative grants of authority to the PUC should be interpreted in a manner consistent with the State's constitutional directive favoring free enterprise. Limitations on the right of the people to "free and fair" competition"... must be construed narrowly, with all doubts resolved against the establishment or perpetuation of monopolies.*[29]

V. Compensation for Avoided Transmission Costs

FURTHER ORDERED, that the Joint Utilities shall and other Parties may file in this docket proposals, including proposed tariff language, within four months of the date of this Order to credit large customer-generators (greater than 100 kilowatts) operating under NM 3.0 for actual avoided Regional Network Service (RNS)

[26] *See, generally,* Hearing Exhibit 13 at 13–19; and Hearing Exhibit 14 at 9:8–14.
[27] *See* Tr. Hearing August 22, 2024 at 236:15–16.
[28] DR 96-150, Order No. 22,875 (issued 3/20/98) at ¶G.ii (under Commission Conclusion -Vertical Market Power).
[29] Id. (citing Appeal of PSNH, 141 N.H. 13, 19 (1996) (internal citation omitted)).

transmission charges[30], where hourly interval metering is available, starting with all new customer-generators greater than 1 MW, calculated and credited manually, if necessary, at least annually; with the cost for any such manual calculation deducted from the credit; and it is

FURTHER ORDERED, Parties may file responsive comments about such proposals within ten business days following their filing; and it is

FURTHER ORDERED, that subsequent to such filings the Commission will issue a supplemental order of notice for any additional process needed to determine how to implement a system that credits large CGs for actual avoided RNS transmission costs, including appropriate line loss factors, if any, and provisions for recovery of utility costs to implement such new system, starting within the next year for customer-generators greater than 1 MW if feasible; and it is . . .

The fact that net metered CGs that function as load reducers can avoid substantial transmission costs is well established in this docket. The VDER Study demonstrates this for all DER types considered.[31] The Coalition's expert witness analyzed all available interval data sets for various types and sizes of net metered generation operating in NH in 2021 and 2022 and compared actual production at each monthly hour of coincident peak demand on which RNS charges are incurred and found that the value of avoided RNS charges alone (not including LNS transmission) ranged from 0.94 to 1.76 ¢/kWh.[32] The analysis by the CENH witnesses also confirmed substantial avoided transmission cost value[33] that results in under compensation of large CGs.[34] The key new requirement the Commission

[30] Actual avoided RNS transmission charges should be based on each CG's metered exports to the grid at the monthly hour of coincident peak demand on which such charges are based, but only for CGs that function as load reducers (i.e., are not ISO-NE market participants) and thus cause actual avoided RNS charges.
[31] *See* Tr. Hearing August 20, 2024 at 16:16–20; Hearing Exhibit 8 at 85–87, 91–92, 95, 98–99.
[32] *See* Hearing Exhibit 13 at 19:2–22:18, 54–57; s*ee also* Hearing Exhibit 14 at 9:8–14.
[33] *See* Hearing Exhibit 5 at 25:1–2.
[34] *See* Hearing Exhibit 5 at 20:11–13, 21–23, 39:1–6. *See also* Tr. Hearing August 20, 2024 at 204:19–206:9; and Tr. August 22, 2024 at 39:7–40:17, 107:14–111:1.

must consider in this docket includes "balancing the interests of customer-generators with those of electric utility ratepayers by maximizing any net benefits while minimizing any negative cost shifts from customer-generators to other customers and from other customers to customer-generators," RSA 363-A, XVI. This is a case where CGs are causing a cost reduction in the form of avoided RNS (and LNS) charges for which they receive no credit or benefit, resulting in a negative cost shift from other customers to CGs. By crediting new large CGs for avoided RNS charges, more such projects are likely to move forward and thus create a net benefit for ratepayers in the form of avoided LNS charges.

Further, this provision of a temporal price signal, where none exists in the status quo, should produce more economically efficient and optimal outcomes as explained by the Coalition's witness and thus greater net benefits over time.[35] The hearing testimony of Eversource witness Mr. Brian Rice supports this position: "We're asking them [large distributed generators] to moderate their output and spread it out over a longer period of time. Because when you do that, you don't contribute to circuit saturation as much. So, we get more benefit out of the investments we're making. We can do more distributed generation with the same investment." Although Mr. Rice posited that the Coalition proposal to recognize actual avoided transmission costs would somehow incentivize output at the single hour of coincident peak demand, as Mr. Below explained, recognizing this temporal price signal would incentivize projects to spread their production out over more hours of the day to shave periods of peak demand that can extend into the later afternoon and early evening hours when hours of coincident peak demand, daily and monthly, tend to occur.[36] Mr. Below also noted that the more Distributed Energy Resources (DRs) that try to reduce load at hours of monthly and annual coincident peak demand the more hours will need to be targeted to capture that value, the more the peak will be clipped, and the more capacity will be freed up for new loads, so as to reduce the need for expensive new capacity

[35] *See* Hearing Exhibit 13 at 20–21; Hearing Exhibit 14 at 3:11–23, 8:4–16, 9:8–10:2; Hearing Exhibit 32 at 6–8, 12–13; *see also* Tr. Hearing August 22. 2024 at 107:17–111:1, 277:22–279:17, 281:11–284:13, 287:5–290:19.
[36] *Id.*

investments to meet peak demand with DERs as non-wires alternatives to investment in more transmission capacity competing based on the same price signal reflecting the marginal cost of new transmission investment.[37]

At hearing and by this brief, the Coalition asks the Commission to take administrative notice of the relevant portions of three dockets in which each of the Joint Utilities filed proposals for utility investment in distributed generation (DG) or distributed storage (DS), functioning as load reducers relative to the ISO-NE market and transmission, that counted the value of avoided RNS and LNS charges in their benefit/cost analysis.[38] The three cases are DE 17-189[39] Liberty's battery storage pilot; DE 19-057[40] Eversource's Westmoreland Clean Innovation Project; and DE 22-073[41] Unitil's single axis tracker solar project. These cases are relevant because they contradict the assertion by the Joint Utilities that transmission charges levied based on share of coincident peak demand are not price signals or something large CGs should receive any credit for.[42] These dockets illustrate the same type of inequities amongst utilities supplies and CPAs and CEPS as discussed above with respect to the utility suppliers' ability to socialize all the costs of compensation to net metered CGs through mechanisms such as the Stranded Cost Recovery Charge or some other non-bypassable delivery charge whereas CPAs and CEPS cannot. Similarly, these three dockets evince the fact that these utility suppliers outside of this docket engage in DG for the benefit of load reduction, including counting the value of avoided RNS and LNS charges in their benefit/cost analysis, but in this docket, those same utility suppliers argue that non-utility DG cannot now do that. These three dockets show how the very same discrimination is baked in when CPAs, CEPS, and

[37] *Id.*
[38] Tr. Hearing August 20, 2024 at 201:18–202:21.
[39] DE 17-189, Exhibit 2 at 11:18–20, 13:15–21, 17:11–14.
[40] DE 19-133, Testimony of Charlotte B. Ancel at 30:8–11, 31:18–33:12; *see also* Attachment CBA-3 also at tab 1, at 73–90.
[41] DE 22-073, Exhibit 2, "Joint Testimony of Andre J. Francoeur, Todd R. Diggins, Christopher J. Goulding, and Jeffrey M. Pentz, Exhibit FDGP-1 at 214–219.
[42] Hearing Exhibit 3 at 21:17–18.

other DG cannot do the same, putting them and their customers at an unfair structural disadvantage.[43]

Mr. Rice sought to contrast the two in his rebuttal testimony by asserting that a utility investment in solar or storage would not retain that value of "a reduction in the wholesale transmission charges"[44] and that the "benefit from [a] reduction in transmission charges . . . would flow to all utility customers"[45] while a credit for reducing transmission charges as proposed by the Coalition "would be passed on exclusively to the net metered customer instead of all customers."[46] This is not correct as Mr. Below explained in his surrebuttal.[47] Most of the value of a reduction in transmission charges from a utility investment in load reducing DERs in all three of these proposals flows to the utility, to amortize the investment including a return on private equity investment in the project and operating costs. If projected savings are realized, then a modest portion of all cost reductions will flow to benefit all ratepayers. If savings are not realized, then only ratepayers will suffer as the utility investors will still be able to earn a return on their investment as part of distribution rate base. Under the Coalition's proposal of only crediting actual avoided RNS costs to large CGs, all ratepayers will benefit from a reduction in LNS rates, ignored in Mr. Rice's testimony, and the CG, or their off taker will bear the risk of not realizing the RNS transmission cost reduction, not the ratepayer.

Mr. Taylor's[48] assertion that the net benefits analysis to support investment in Unitil's DG project is not analogous to the consideration of compensation of CGs in this docket lacks merit; it is analogous and relevant in all critical respects. Both entail an economic decision on whether to invest funds in new generation functioning as a local load reducer. Both must weigh the cost of investment, including return on the investment, against the potential compensation[49] that in both a market and regulated context should

[43] *See generally* Hearing Exhibit 14 at 9–14.
[44] Tr. Hearing August 22, 2024 at 224:8–13.
[45] *Id.* at 224:15–13.
[46] *Id.* at 224:23–225:8.
[47] *Id.* at 277:22–278:8.
[48] Tr. Hearing August 20, 2024 at. 196:12–16.
[49] *Id.* at 137: 8–16.

be based on the actual value produced, including costs that are avoided. Both are operating in a context where RSA 374-F called for utility divestment of generation resources that "should be subject to market competition."[50]

At the hearing, Chairman Goldner recalled "the locational effect of that particular array was highly beneficial and integral to the calculations that said that it was -- had a positive NPV, so it was sort of a unique set of circumstances . . . ."[51] However, while the location of the project on utility owned land next to a substation is somewhat unique, no value was ascribed to such in the analysis of benefits. Instead, the projected benefits used in the Benefit-Cost analysis were: 1) Avoided Energy Costs, 2) Avoided Capacity Costs, 3) Local Transmission Benefits (consisting of avoided LNS charges), 4) Regional Transmission Benefits (consisting of avoided RNS charges), and 5) the value of produced Renewable Energy Certificates (RECs) that can be used in lieu of purchased RECs for utility default service RPS compliance.[52] Each of these benefits is directly analogous to the core benefits detailed in the VDER Study and those at issue in this docket (except for RECs because CGs can realize REC value through market-based sales). It is also significant that the DOE witnesses in that docket testified that Unitil's assumptions about the benefit of avoided LNS and RNS rates were reasonable.[53] To conclude that regulated monopoly utilities should be able to count the value of avoided transmission costs to offset the cost of their DER investments while CGs >100 kW should not, creates an unlevel playing field where investment by the monopoly is favored over competitive market actors, which is contrary to NH state law and its Constitution.

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

FURTHER ORDERED, that the Joint Utilities shall file in this docket within

[50] RSA 374-F:3, III.
[51] Tr. Hearing August 20, 2024 at 197:18–23.
[52] *See supra* note 41, at 214–218.
[53] DE 22-073, Exhibit 7, Direct Testimony of Mark P. Toscano and Elizabeth R. Nixon, at 17:9–14; *see also* Tr. Hearing August 22, 2024 at 43:9–45:20.

three months of the date of this Order proposed tariff language changes and estimated cost and timetable to implement changes in the energy service compensation rate to be reduced to the equivalent of the Base Energy Service Rate, the rate paid for utility default service supply after adjusting for line losses, initially for only large CGs (greater than 100 kilowatts) and for small CGs if subsequently so ordered; and it is

FURTHER ORDERED, that other Parties may file responsive comments to such proposals within ten business days following their filing; and it is

FURTHER ORDERED, that subsequent to such filings the Commission may issue a supplemental order of notice for any additional process needed to determine how, when, and to what extent to implement such changes including necessary changes to EDI/EBT processes to support competitive suppliers and Community Power Aggregations providing a separate export credit rate and provisions for recovery of utility costs to implement such new system, starting for large CGs when avoided transmission cost credit is implemented; and it is . . .

The difference between the full Default Energy Service Rate and the Base Energy Service Rate paid for actual power supply is primarily comprised of: the cost of RPS compliance for net delivered electricity; the utility cost to administer default service, including the cost of working capital; and prior period over and under recoveries.[54] Instead of using the retail Default Energy Service Rate to compensate net exports to the grid, use what Eversource and Liberty term the "Base Energy Service Rate" that is published in their filings and is the equivalent of what is paid to the supplier (with appropriate line loss adjustments), so excludes those values that are not provided or avoided by CGs. This exclusion does create a negative cost shift from CGs (and/or members of group NM) as, in effect, the CG or group members do not contribute to the RPS compliance obligation for those kWh

[54] Hearing Exhibit 13 at 23:21–27:18; Hearing Exhibit 14 at 4:36–6:5.

compensated as exports when they in turn consume equivalent kWh.[55] This is undue and unreasonable cost shifting because there is a ready and proven solution. Implementing a separate rate for default service exports to the grid by CGs compared with consumption, which was done with the distribution component in 2017, and which NH Electric Co-op has done for the supply portion of their rate by simply adding a new export rate that generates a negative charge (i.e., credit) as the Joint Utilities do now for export credits, but at the same rate as for consumption.[56]

The main argument by the Settling Parties against this cost shift is that "the parties agree it's a negligible change that wouldn't be particularly constructive," the utilities would need to update billing systems, and it could cause customer confusion.[57] As the Coalition has testified and provided evidence for, this could cause a substantial amount of cost shifting over time, especially with a legacy period of 15 to 20 years, potential growth of CGs in the 100 kW to 5 MW range, and if the cost of RPS compliance obligations grows.[58] The cost to implement is largely a one-time cost and customer confusion could be minimized if this is implemented incrementally, starting initially with large CGs (> 100 kW) or by excluding residential rate classes altogether.[59]

VII. Compensation for Avoided Capacity Costs to Load Serving Entities from Customer-Generators.

FURTHER ORDERED, that the Joint Utilities convene a stakeholder group of interested parties within three months to consider how, under state jurisdiction without interfering with ISO-NE requirements, CGs that are customers of suppliers other than the utility can receive credit for actual avoided ISO-NE Forward Capacity Market charges by reducing the capacity load obligation, and the Joint Utilities shall

[55] Hearing Exhibit 13 at 23: 21–24; Hearing Exhibit 14 at 4:3–5:3: *see also* Hearing Exhibit 32 at 5 at 9–11.
[56] *See* Hearing Exhibit 13 at 10:22–25.
[57] Tr. Hearing August 20, 2024 at 133:6–134:8.
[58] *See* Hearing Exhibit 13 at 24:20–28; Hearing Exhibit 14 at 5:4–5:5; Hearing Exhibits 15, 16, and 28; and Tr. Hearing August 22, 2024 at 135:1–136:10.
[59] *See* Hearing Exhibit 13 at 30:27–31:13; and Tr. Hearing August 22, 2024 at 138:14–138:24, 141, 176:4–177:16; and Hearing Exhibit 17.

and other parties may file proposals for such within 9 months of this Order; and it is

FURTHER ORDERED, that subsequent to such filings the Commission may issue a supplemental order of notice for additional process needed to determine how, when, and to what extent to implement credit for avoided capacity costs, and it is . . .

Providing a credit for avoided capacity costs for CGs that are not on utility default service may be more nuanced than providing a credit for avoided RNS transmission charges so the proposed timetable for further consideration is more relaxed.[60] The same arguments and evidence concerning the need to enable a level playing field between utility default service NM and NM programs provided by CPAs and CEPS with regard to credit to large CGs that can create avoided transmission costs applies to avoided capacity costs, except that this is only an issue for CGs not on utility default service, since the Base Energy Service Rate includes credit for capacity costs.[61]

VIII. Distributed Storage (DS)

FURTHER ORDERED, that the Joint Utilities shall file in this docket within nine months of the date of this Order proposed tariff language enabling Distributed Storage to be interconnected and compensated as part of net metering, after which the Commission will issue a supplemental order of notice for consideration of same; and it is . . .

Considerable evidence supports adding DS to DG can materially increase the overall benefits of NM.[62] The Legislature has called for action on this,[63] so now is an appropriate time to move this forward with supplemental notice for consideration of such tariff changes.

[60] *See* Hearing Exhibit 13 at 22–23.
[61] Hearing Exhibit 13 at 22:21–23:20.
[62] *See* Hearing Exhibit 13 at 10:26–28, 28:9–30:25; Hearing Exhibit 5 at 40:14–41:18; Hearing Exhibit 7 at 13:5–21; Hearing Exhibit 8 at page 71; Hearing Exhibit 32 at pages 6–9; Tr. Hearing August 20, 2024 at 69–71:2; Tr. Hearing August 22, 2024 at 40:9–15, 226:9–20.
[63] *See* Hearing Exhibit 13 at 28:10–19; Tr. Hearing August 22, 2024 at 139–40; and RSA 374-H:2, I.

IX. Time-of-Use (TOU) Rates

FURTHER ORDERED, where utilities have existing three-part TOU rates, they propose tariffs to allow the opt-in for net metering for CGs in such rate classes within six months of this Order, after which the Commission will issue a supplemental order of notice for consideration of same; and it is

FURTHER ORDERED, that CGs participating in NM 3.0 should be on notice that at some point in the future, within the legacy period, they may be required to convert to TOU rates; and it is . . .

Abundant evidence in the record demonstrates that TOU rates for NM can provide a more accurate price signal reflective of the temporal value of DG and result in increased overall benefits from NM.[64]

X. Dual Participation in ISO-NE Markets

FURTHER ORDERED, that under NM 3.0, any CG that is participating in the ISO-NE market will be ineligible to receive credit for avoided transmission charges and will be subject to a reduction in the compensation at the full Default Energy Service Rate credit to the Base Energy Service Rate when that is implemented.

The Coalition has provided abundant evidence and argument concerning allowing generators to simultaneously participate in state jurisdictional NM and ISO-NE wholesale markets,[65] not the least of which is that they do not function as load reducers and therefore, cannot generate any avoided transmission, energy, or capacity costs. On that basis, those CGs that participate in NM 3.0 should be excluded from any credit for avoided transmission charges.

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[64] *See* Hearing Exhibit 13 at 30–31; Hearing Exhibit 14 at 6:9–13, 7:12–8:16; *see also* Hearing Exhibit 7 at 12:5–21; and Tr. Hearing August 22, 2024 at 35:11–26:6, 39:7–40:8.

[65] *See* Hearing Exhibit 13 at 16:3–19:1; Hearing Exhibit 14 at 10:3–14:3; Hearing Exhibits 18–27; Exhibits 20 and 22–24 are the questions Eversource posed to the Coalition witness which the Coalition answered *pro se* without receipt of any objection to its answers.