**BEFORE THE PUBLIC UTILITIES COMMISISON**
**STATE OF NEW HAMPSHIRE**

**DE 23-026**

**ELECTRIC DISTRIBUTION UTILITIES**

**Potential Jurisdictional Conflicts Related to Authorization of Pilot Programs Under RSA 362-A:2-b**

June 23, 2023

**Community Power Coalition of New Hampshire Initial Brief on Jurisdiction**

The Community Power Coalition of New Hampshire ("CPCNH" or "Coalition") by its Chair submits this brief pursuant to PUC 203.32 and the Public Utilities Commission's ("PUC" or "Commission") Procedural Order following Prehearing Conference dated May 16, 2023.

## INTRODUCTION

On June 17, 2022 Governor Sununu signed into law SB 321, making it Chapter 218 of NH Laws of 2022. This act was effective upon passage and amended the definition of "limited producer" or "limited electrical energy producer" in RSA 362-A:1-a, III; added a new definition of "qualifying storage system" as RSA 362-A:1-a; and added a new section to Chapter 362-A, the Limited Electrical Energy Producers Act (LEEPA), Section 2-b; authorizing certain pilots for how limited producers could sell power locally over the distribution system. RSA 362-A:2-b, III provides that:

> Before approving any pilots authorized in paragraph II, the commission shall open a docket to determine definitively whether any jurisdictional conflicts exist concerning the use of the distribution or transmission system, including a determination about whether the activities allowed by this chapter would require a utility to violate its transmission owners operators agreement or require a recalculation of any ISO-NE open access transmission tariffs, and whether such projects produce avoided transmission cost savings. Upon successful resolution of these questions, the commission may approve pilot projects.

In its May 16, 2023 procedural order the Commission asked parties to submit briefs on the two threshold jurisdictional questions:

a. Whether any jurisdictional conflicts exist concerning the use of the distribution or transmission system; and

b. Whether the activities allowed by RSA chapter 362-A would require a utility to violate its transmission owner operator's agreement or require a recalculation of any Independent System Operator-New England (ISO-NE) open access transmission tariffs.

This brief answers the first question by explaining why no unavoidable jurisdictional conflicts exist concerning the use of the distribution or transmission system for the type of pilots enabled by RSA 362-A:2-b and then further argues that the activities allowed under RSA 362-A[1] do not require a utility to violate its transmission owners operator's agreement[2] or require a recalculation of any ISO New England open access transmission tariffs.[3]

## BACKGROUND

To contextualize this matter, it is perhaps significant to note that New Hampshire's LEEPA statute was first enacted in 1977 following the 1973-1974 "Arab Oil Embargo" that disrupted petroleum supplies for electric generation, at a time when utilities were more dependent on imported oil than today. This was a year before the US Congress enacted the Public Utility Regulatory Policies Act of 1978 (PURPA), though modeled on the same concept, designed to open up a market for independent power producers using renewable energy or cogeneration of fossil fuels (for combined heat and power). The original purpose statement of LEEPA still survives today as the first sentence in RSA 362-A:1: "Declaration of Purpose. It is found to be in the public interest to provide for small scale and diversified sources of supplemental electrical power to lessen the state's dependence upon other sources which may, from time to time, be uncertain."

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[1] Although the statute does refer to "this chapter" apparently referring to the LEEPA RSA Chapter 362-A as a whole in seeking a PUC determination as to whether any activities allowed under it would require a utility to violate its operating agreement, presumably the main concern of the legislature is the pilots contemplated under RSA 362-A:2-b, as such a concern has not been raised about the rest of the chapter to the Coalition's knowledge.

[2] Presumably here the statute is meant to refer to the "Transmission Operating Agreement" between Participating Transmission Owners ("PTOs") and ISO New England Inc. (ISO-NE) found here: https://www.iso-ne.com/static-assets/documents/regulatory/toa/v1_er07_1289_000_toa_composite.pdf. The Coalition has not identified any other document that might be considered a "transmission owners operator's agreement."

[3] Although the statute and the Commission order refer to ISO-NE open access transmission *tariff**s***, in the plural, there is actually only one Open Access Transmission Tariff (OATT) that includes different Schedule 21 provisions for local network service from the various local transmission network providers in contrast to the main body of the OATT that covers regional network services, among other matters.

Thus began, with LEEPA and PURPA, more than 4 decades or parallel and complementary efforts by the State of New Hampshire and our Federal Government, through the PUC and Federal Energy Regulatory Commission ("FERC"), a public policy and regulatory effort to open up the electric utility system to competition, organized markets, and customer choice in the generation and supply of electricity. For FERC its efforts have been in furtherance of its core responsibility to "guard the consumer from exploitation by non-competitive electric power companies."[4] For NH the "transition to competitive markets for electricity" supports "the directives of part II, article 83 of the New Hampshire constitution which reads in part: 'Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it.'"[5]

The Energy Policy Act of 1992 encouraged FERC to foster competition in wholesale energy markets through open access to transmission facilities. In 1996 FERC initiated the rule making process that led in the spring of 1996 to Order No. 888 adopting final "rules designed to remove impediments to competition in ***the wholesale <u>bulk</u> power marketplace*** and to bring more efficient, lower cost power to the Nation's electricity consumers."[6] (Emphasis added.) After a

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[4] https://www.ferc.gov/industries-data/electric/power-sales-and-markets/electric-competition, excerpted in part below:

**Electric Competition**

National policy for many years has been, and continues to be, to foster competition in wholesale power markets. In each major energy bill over the last few decades, Congress has acted to open up the wholesale electric power market by facilitating entry of new generators to compete with traditional utilities. As the third major federal law enacted in the last 30 years to embrace wholesale competition, the Energy Policy Act of 2005 strengthened the legal framework for continuing wholesale competition as federal policy for this country. The Commission has acted quickly and strongly over the years to implement this national policy.

The Commission's core responsibility is to "guard the consumer from exploitation by noncompetitive electric power companies." The Commission has always used the following two general approaches to meet this responsibility:

**Regulation** - was the primary approach for most of the last century and remains the primary

approach for wholesale transmission service.

**Competition** - has been the primary approach in recent years for wholesale generation service. Advances in technology, exhaustion of economies of scale in most electric generation, and new federal and state laws have changed the Commission's views of the right mix of these two approaches. The Commission's goal has always been to find the best possible mix of regulation and competition to protect consumers from the exercise of monopoly power.

[5] RSA 374-F:1, II

[6] *75 FERC 61,080,* ("The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce.").

couple of years of study, that same spring NH became the first state in the nation to enact an "Electric Utility Restructuring" statute "to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets."[7] Like Order 888, NH's law called for unbundling of services and rates such that "[g]eneration services should be subject to market competition and minimal economic regulation and at least functionally separated from transmission and distribution services."[8] Like Order 888, NH's law called for "non-discriminatory open access" to "Transmission ***and Distribution Facilities***" "for wholesale ***and retail*** transactions."[9] (Emphasis added.) Of course, pursuant to the division of jurisdiction by the Federal Power Act of 1935[10], only state law and regulation could extend the idea of retail access to competitive electricity markets over the electric with retail customer choice "of generation sources, including interconnected self-generation."[11] NH acted in concert with FERC, relying on their development of competitive wholesale markets for bulk generation that used the FERC jurisdictional transmission grid with nondiscriminatory open access to deliver most of the power to the state jurisdictional distribution grids that in turn supplied power to retail customers.

In furtherance of customer choice, Chapter 129, NH Laws of 1998[12] enacted a number of reforms to LEEPA that included: 1) terminating the obligation of utilities to purchase the output of electric energy by limited electrical energy producers that offered it to them where retail electric competition was certified to exist by the PUC;[13] 2) eliminating a prohibition on buyouts of existing contracts by utilities under LEEPA/PURPA;[14] 3) creating net metering for generation by systems no larger than 25 kW; and 4) expanded the potential number of customers that a limited producer could sell to and authorized the Commission to allow purchasers of power from a limited producer to "not be charged a transmission tariff or rate for such sales if transmission

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[7] RSA 374-F:1, I

[8] RSA 374-F:3, III

[9] RSA 374-F:3, IV

[10] 16 U.S. Code Chapter 12, §§ 791-825

[11] RSA 374-F:3, II

[12] Chapter 129, NH Laws of 1998: https://www.gencourt.state.nh.us/legislation/1998/HB0485.html

[13] By Chapter 129:6 and 129:7 amending RSA 362-A:3 and 362-A:7 respectively.

[14] By Chapter 129:15 repealing RSA 362-A:4-b.

facilities or capacity under federal jurisdiction are not used or needed for the transaction."[15] It was not until 2006 that FERC terminated most of the obligation of utilities to purchase power from qualified facilities (QFs) under PURPA where organized wholesale markets enable QFs to receive market-based compensation.[16]

Enactment of RSA 362-A:2-b is an important policy step towards better enabling local competitive markets that supports state policy goals and can complement and work in harmony with FERC policy, tariffs, and jurisdiction.

## FACTUAL PREDICATE

At issue here is how the generation output from a limited producer may be accounted for relative to state and federal jurisdiction. A "limited producer" as defined in RSA 362-A:1-a, III is treated as a load reducer for the provision and cost allocation of FERC jurisdictional services from ISO New England. RSA 362-A:1-a, III defines the term thus:

> "Limited producer" or "limited electrical energy producer" means a qualifying small power producer, a qualifying storage system, or a qualifying cogenerator, with a maximum rated generating or discharge capacity of less than 5 megawatts that:
>
> (a) Does not participate in net energy metering. Non-participation in net energy metering may be achieved by canceling participation in such upon assuming limited production.
>
> (b) Is not registered as a generator, asset, or network resource with ISO New England.
>
> (c) Does not otherwise participate in any FERC jurisdictional wholesale electricity markets, except as an alternative technology regulation resource (ATRR) to the extent ATRRs are deemed by ISO New England to function as retail or network load reducers for all other ISO New England purposes. Such non-participation in FERC jurisdictional interstate wholesale markets may be achieved by retirement from such "

ISO New England's Operating Procedure (OP) No. 14 provides that any generating facility (which includes energy storage facilities capable of injecting power into the grid) that is interconnected at 115 kV or greater, or is 5 MW or greater, must register with ISO New England as a "Generator" (also known as a Generator Asset, or Network Asset). Generating facilities that are under 5 MW and interconnected below 115 kV may register with ISO New England but "[m]ay elect to **not** register, or to register as an ATRR only, if **not** participating in any New England Markets other than as a load reducer or regulation provider." Power lines below 115 kV

[15] Chapter 129:5, NH Laws of 1998 amending RSA 362-A:2-a, I.

[16] Order No. 688, 117 FERC ¶ 61,078 (2006).

are generally state jurisdictional distribution facilities in New England and those facilities operating at 115 kV and above are generally considered to be FERC jurisdictional facilities transmitting power in interstate commerce. There is usually a meter at the point of interconnection between the distribution grid and the transmission grid to measure the power flows at that point. Eversource is understood to not have meters at all these interconnection points in New Hampshire but estimates the hourly load at these interconnection points instead, presumably with a method that closely approximates what a meter would read if there was one.

Network Load is the basis for allocating transmission costs and is a defined term in the OATT. After years of controversy and confusion as to what was meant by a provision in the definition of Regional Network Load (RNL) in the OATT that said "that load served by behind-the-meter generation should not be excluded from the determination of the RNL"[17] FERC approved OATT tariff revisions "to exclude from the Monthly RNL load served by unregistered behind-the-meter generation"[18] In the OATT the precise phrase is "Network Customer's Monthly Regional Network Load shall exclude (i) load offset by any resource that is not a Generator Asset . . ."[19] There is no qualification as to how those distributed generators use or sell their power exported to the distribution grid as to their treatment relative to transmission cost allocation, that is whether or not they participate in net metering, group net metering, retail, or local, with state, wholesale sales of their power for consumption within the state; they are all treated as load reducers relative to FERC jurisdictional markets and transmission.

## JURISDICTIONAL QUESTIONS FRAMED BY JOINT UTILTIES WITH INITIAL RESPONSES

At the pre-hearing conference Eversource raised several jurisdictional questions that they thought should be addressed in briefs, including:

1. "**The first, it is a question "whether any wholesale sale of power in New England can be intrastate and state jurisdictional, rather than interstate and FERC jurisdictional?"** (Tr at 9). Under RSA 362-A:2-b, pilots limited producers could be authorized by the PUC to sell at retail (except to residential customers) or at

[17] 178 FERC ¶ 61,086 (2022), "Order Accepting Tariff Revisions" issued 2/11/22 in Docket No. ER21-2337-002.
[18] *Id.* at 21.
[19] ISO New England OATT, §II.21.2, Effective Date: 9/1/2021 - Docket #: ER21-2337-002.

wholesale for resale within the state[20] (intrastate wholesale). The Coalition agrees this is the primary jurisdictional question here and argues that the only logical and lawful conclusion is that electricity can be sold for resale (wholesale) with the state under state jurisdiction rather than in interstate commerce under FERC jurisdiction. As discussed in more detail below, this is consistent with a) the physics of electricity, where some sales of electricity and injection into the distribution grid reduce the amount of power that flows onto the distribution grid from out-of-state generation over the FERC jurisdictional transmission grid (and thus are treated as "load reducers" relative to FERC jurisdictional energy markets and transmission); and b) federal law, specifically 16 U.S.C. § 824(b)(1).

2. **Whether the statute or a regulatory order by the PUC can direct an EDU or a market participant in the ISO system to report its retail loads and/or the loads of other load-serving entities, for purposes of energy, capacity, transmission, and any other FERC jurisdictional services, purchased at wholesale, from or through or otherwise assessed by the ISO, to serve retail load in a manner different than would otherwise be done under ISO rules and procedures . . . ?"** We agree that such an order or directive would create a jurisdictional conflict, but the Coalition does not read the statute as enabling such order or directive, so this should not be an issue. Furthermore, since pilots must be proposed by an EDU, in conjunction with a CPA or a CEPS pursuant to RSA 362-A:2-b, VII there is no reason to believe a pilot proposal would come forward that would cause such a reporting of loads for the purpose of any FERC jurisdictional services in violation of any ISO rules and procedures.

3. **Whether the statute or a regulatory order by the PUC "can address the capacity supply obligations of ISO-New England capacity suppliers without being preempted by federal law?"** On the face of it, CPCNH does see how full implementation of RSA 362-A:2-a, XIII could create an impermissible jurisdictional conflict that could be preempted by federal law, assuming the prescriptive manner in which ISO New England calls for capacity load obligations to be allocated to

[20] RSA 362-A:2-b, VIII.

individual retail customers in not an impermissible intrusion into the state's exclusive jurisdiction over retail sales of electricity.[21] However, even to the extent that this provision of the statute may create such a conflict, it is not an unavoidable or insurmountable barrier to the implementation of limited producer pilots as explained below under §VII. The overall capacity obligation of the meter domain should not change so capacity supply obligation to Generators registered with ISO-NE should not be impacted in any way.

4. **Whether the statute or a regulatory order by the PUC "can address how transmission charges assessed by the ISO to network customers may or may not be allocated to load-serving entities . . . without being preempted"?** This is an issue of retail rate design under state jurisdiction. The principal obligation of a state commission with regard to transmission charges assessed to a network customer, here EDUs, is to ensure that they are able to fully recover those ISO transmission charges.[22] Every retail customer account in NH must be served by one electricity supplier at any point in time. Each supplier, whether a CEPS, a CPA, or EDU default service, must either be a load serving entity (LSE) and/or working contractually with one to serve retail load. In their capacity serving retail load the state, whether by statute or regulation, has considerable authority over them in the terms and conditions and rates they may charge retail customers. The statute allows that the sponsors of a pilot, which much include and EDU, "may petition the commission to determine, through an adjudicated proceeding, how credits for actual avoided transmission charge are to be made."[23] Among the options, which by their nature are voluntary by the pilot sponsors which would necessarily include the supplier and LSE serving the limited producer account, is to allow suppliers (LSEs) to charge groups of retail

[21] 16 U.S.C. §824(b) as cited in FERC v. Electric Power Supply Assoc., 136 S.Ct. 768 (2016): "the Act also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction. As pertinent here, §824(b)(1)—the same provision that gives FERC authority over wholesale sales—states that "this subchapter," including its delegation to FERC, "shall not apply to any other sale of electric energy." Accordingly, the Commission may not regulate either within-state wholesales sales or, more pertinent here, retail sales of electricity (*i.e.*, sales directly to users). See *New York*, 535 U. S., at 17, 23. State utility commissions continue to oversee those transactions.'"

[22] *See* Narragansett Electric Co. v. Burke, 122 R.I. 13, 404 A.2d 821 (1979)

[23] RSA 362-A:2-b, XI(a)

customers for their actual share of transmission costs based on their share of coincident peak, including the load reducing effect of a limited producer in the ISO assessment of such charges, in what would essentially be a retail transmission cost pass through from the EDU through the retail supplier/LSE. As further discussed in § below, this is not unlike how FERC transmission charges are translated into retail rates in Eversource's territory in Massachusetts and in Pennsylvania in the PJM ISO.

5. **And whether the statute or a regulatory order by the PUC "can find that a transmission charge has been avoided by a customer load deemed to be served by a limited electrical energy producer, when ISO-New England would not, in fact, charge such customer load for transmission under the current tariff construct? And whether any such statute, rule, or order, including SB 321, is permitted to result in trapped transmission costs."** The Coalition does not see how a limited producer pilot could result in any "trapped transmission costs". By the terms of the OATT, limited producers would be treated as load reducers relative to transmission cost allocation. So, to the extent they put power onto the distribution grid at the hour of monthly coincident peak when transmission charges are assessed, they would reduce those charges from what they would otherwise be. How credit for that might realized through retail rates is a state jurisdictional matter as further discussed in §V and §VI below.

## ADDITIONAL ARGUMENT

CPCNH submits that interconnections to the distribution grid and intrastate sales for resale located entirely within state are a matter for state jurisdictional authority and not a matter of interstate commerce subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC" or "Commission").

### I. NH law grants NH municipalities the right to develop, own and operate electric generation including limited producers and choose who to sell the produced power to.

NH municipalities have authority under several state statutes to develop, own, operate and contract for electric generation facilities, and decide to whom to sell the power, whether at retail or wholesale. Aside from owning and operating electric distribution utilities that are exempt from PUC regulation under RSA 38, since 1981, more than a decade before the Energy Policy Act of 1992 and Order 888, RSA 364-D has granted municipalities broad authority to "design, develop, acquire, and construct small scale power facilities at sites owned or leased by them. . . . Power produced by such facilities may be transmitted and distributed by a municipality to any user of power or to any public utility, at such price and on such terms and conditions as may be agreed to by the governing board."[24] "Small scale power facilities" is defined in such a way that those facilities under 5 MW could qualify as limited producers when interconnected to the distribution grid and selling their output locally.

Since 1979 RSA 362-A:2-a has granted limited producers "the authority to sell its produced electrical energy to not more than 3 purchasers other than the franchise electric utility, unless additional authority to sell is otherwise allowed by statute or commission order. Such purchaser may be any individual, partnership, corporation, or association." The authority to sell to more than 3 purchasers with commission approval was extended in 1998. If the limited producer sells at retail, the contract for such is subject to review and approval or disapproval of the PUC with a public good determination, but the PUC can't set the terms of such contracts. There are also provisions for PUC approval of "wheeling" agreements between the producer and local retail utility to transmit the power from producer to purchaser with the transmitter compensated for all costs incurred in wheeling and delivery. The PUC also "retains the right to order such wheeling and to set such terms for a wheeling agreement including price that it deems necessary."[25]

Under RSA 53-E:3 municipalities and counties have the authority to provide or contract for the "supply of electric power and capacity,"[26] provide other related energy services, and to sell that power and those services to retail customers within their jurisdiction through opt-in programs or opt-out alternative default service. RSA 53-E:3-a allows municipal aggregators to use revenue bonds pursuant to RSA 33-B and RSA 374-D and use certain loans from municipal enterprise funds for purposes "such as generation, storage, or sale of power generated from sites, facilities, or resources that might otherwise be operated or produced by the other enterprise fund"

[24] RSA 374-D:2.

[25] RSA 362-A:2-a, II

[26] RSA 53-E:3, II(a)(2).

these could include water, wastewater, solid waste, and airport enterprise funds. RSA 53-E:4, I authorizes CPAs to "elect to participate in the ISO New England wholesale energy market as a load serving entity for the purpose of procuring or selling electrical energy or capacity on behalf of its participating retail electric customers, including itself." Accordingly, CPAs have authority to both generate power and sell at retail as well as to generate and sell or buy at wholesale for resale, either locally, under state jurisdictional authority, or in the ISO New England bulk interstate wholesale market under FERC jurisdictional authority. CPAs may thus participate in both intrastate and interstate wholesale commerce.

RSA 53-E:3, II(b) allows municipalities and counties to operate such community power aggregations individually or jointly through RSA 53-A, which is how the Coalition operates as a governmental instrumentality of its 34 subdivisions of the state with the authority to exercise all the municipal authorities referenced herein.

## II. In examining jurisdictional issues, FERC has expressed uncertainty about its jurisdictional authority and recently has instead erred on the side of caution and allowed states to exercise jurisdiction over sales at wholesale within a given state.

FERC has recently examined these jurisdictional issues in two important Orders issued last year (after the LEEPA Study Commission) regarding interconnection requirements, and OATT amendments and declined to weigh-in on legal questions raised in two important cases.[27]

In New England any generator with a rated interconnection of 5 MW or more is required to register with ISO-NE and as such is FERC jurisdictional. Generators smaller than 5 MW have the option of registering with ISO-NE and, if they decline to, then such generators remain purely state jurisdictional. Under the ISO-NE OATT approved in the Commission's February 11, 2022 Order in Docket No. ER21-2337, distributed generation and distributed storage that are under 5 MW, interconnected to the distribution grid, and not registered as a generator with ISO NE(*i.e.* not participating in a FERC jurisdictional interstate wholesale market and not trying to sell across state lines) can function as a "load reducer" under ISO-NE operating procedures (OP-14).

[27] See the Commission's February 11, 2022 Order in Docket No. ER21-2337 and the August 26, 2022 in Docket No. ER22-2226, the first two cases and the other two that they declined to act in were 172 FERC ¶ 61,042 New England Ratepayers Association, Docket No.EL20-42-000, *Order Dismissing Petition For Declaratory Order, (2020)* and previously

In a second Order issued on August 26, 2022 in Docket No. ER22-2226, FERC also approved OATT revisions that make clear that the interconnection of such DG & DS is a purely state jurisdictional issue..

The Commission's Order emphasized the uncertainty in whether it could exercise jurisdiction over distribution-level interconnections and noted that disclaiming FERC jurisdiction, and instead approving state jurisdiction, was consistent with the Commission's policies. Specifically, the Commission's August 26, 2022 Order in Docket No. ER22-2226 approved ISO-NE's proposal to exclude DERs from its interconnection procedures as just and reasonable and stated the following:

> [A]n increase in distribution-level interconnections could create uncertainty as to whether certain interconnections are subject to Commission jurisdiction or state/local jurisdiction, and whether they would require the use of the Commission's standard interconnection procedures and agreement. Additionally, the increase in interconnection requests from DERs could burden ISO-NE with an overwhelming volume of interconnection requests. We also find that permitting DERs in ISO-NE to interconnect through the state interconnection process advances the objectives of Order Nos. 2003 and 2006 by increasing energy supply and lowering wholesale prices for customers by increasing the number and variety of new generation that will compete in the wholesale electricity market, while ensuring processes are in place to preserve reliability. . . . [W]e note that disputes related to state interconnection procedures that do not implicate these wholesale market issues will be more appropriately resolved through a state process.[28]

This language indicates that the Commission itself recognizes the uncertainty of the Commission's jurisdictional authority over interconnections to the distribution grid. In the midst of this uncertainty, the Commission erred on the side of caution and, instead of exercising jurisdiction and impeding on the state's authority, approved the exercise of state jurisdiction. As noted by the Commission, this decision was supported by the Commission's own policies in Order Nos. 2003 and 2006.[29] The Coalition submits that the same reasoning applies in this case with respect to limited producers which are a type of DER.

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[28] *ISO New England, Inc.*, 180 FERC ¶ 61,129, at PP 20-21 (Aug. 26, 2022).

[29] This Order also indicates that the Commission is moving away from the reasoning in its 2010 Order July 2010 Order in Docket No. EL10-64, where FERC rejected a utility's request that the Commission disclaim jurisdiction over sales by generators connected to a utility-owned distribution system. *See California Pub. Utils. Comm'n*, 132 F.E.R.C. ¶ 61,047 at P 18 (2010) Those actions, or lack thereof, include By exercising its discretion to dismiss the petition for Declaratory Order by New England Ratepayers Association in Docket No. EL20-42-000, (7/16/20), 172

That the Commission retained jurisdiction over the distributed generators and distributed storage at issue in Docket No. ER 22-2226 only to not allow state commissions or state law to block access to the ISO-NE wholesale market does not challenge in any way the Commission's overall decision that distributed generation and storage interconnections are a state jurisdictional issue. Indeed, the Commission's limited retention of jurisdiction emphasizes the distinction between FERC and state jurisdiction, as FERC retained jurisdiction over an area distinctly within its jurisdictional authority: federal interstate wholesale power market access. It is also significant to note that in neither case were the Commission's Orders (or the petitions in either case, including that sponsored by Eversource on behalf of transmission owners) limited to generation participating in net metering or only "retail sales." Thus, the Commission's reasoning and analysis applies in this case to limited producers.

The Commission's Orders are also consistent with the PUC's broadly accepted jurisdiction and decision in DE 22-073, which was based on the same "load reducer" value stack recognized in the VDER study and proposed in RSA 362-A:2-b for competitive intra-state sales of such DG & DS output (whether at wholesale or retail) as a market based alternative to net metering expansion to 5 MW. This kind of market-based approach is exactly what RSA 374-F calls for, along with FERC and national policy to foster competition in wholesale power markets.[30] In addition, the PUC's authority over limited producers is consistent with its current jurisdiction over energy efficiency, demand response, and utility investment in DERs and inconsistent with FERC's authority. In the past, much of FERC's focus has been on rate setting or mandated purchases authority, but this case involving limited producers is different. Here, the PUC's rule relates to how to give credit for actual avoided transmission and capacity costs that would otherwise be incurred by retail ratepayers in general but for the limited producer's functioning as a load reducer at hours of coincident peak demand pursuant to *already*-approved

FERC ¶ 61,042; by its Notice of Intent Not to Act in Docket Nos. EL 13-60-000 and QF 13-402-001 where Otter Creek Solar petitioned for enforcement action against the Vermont Public Service Board "arguing that the avoided cost rate pricing determination and mechanism in the Vermont Commission's feed-in tariff program, referred to as the Sustainably Priced Energy Enterprise Development (SPEED) program, violates PURPA and the Federal Power Act (FPA)" 143 FERC ¶ 61,282, June 27, 2013, and by it order in PJM allowing netting out DG from network load and likewise for New England, as well as its 2022 orders in ER21-2337-002 and Order 20220826-3066 in Docket No. ER22-2226-000 (180 FERC ¶ 61,129).

[30] FERC, *Electric Competition*, https://www.ferc.gov/industries-data/electric/power-sales-and-markets/electric-competition.

FERC tariffs and procedures. Thus, in this case, FERC is not exercising its traditional role of rate setting or mandated purchases authority. Further, the PUC's role here regarding limited producers is similar to the PUC's existing role of reviewing and approving how a credit is to be realized for investments in energy efficiency, demand response, and utility investment in DERs pursuant to RSA 374-G.

The Commission's decisions in Docket Nos. ER21-2337 and ER22-2226 are also supported by the academic literature. For instance, one 2013 article published in the Energy Law Journal stated argued the Commission does not have jurisdiction over interconnections to the distribution system and intrastate wholesale transactions:

> "In 'light of our history and the structure of our government,' [FN: 203 *Connecticut Light & Power*, 324 U.S. at 531.] and upon a careful analysis of the [Federal Power Act ("FPA")] and its case law, we submit that certain wholesale sales on distribution circuits are not in "interstate commerce" as that term is used in the [FPA],[FN 204: 16 U.S.C. §§ 791-828(c)], and are therefore state jurisdictional. An intrastate wholesale, under prevailing rules, is one that occurs on local distribution facilities to satisfy a buyer's loads [collocated] on the local distribution facilities. We readily concede that generators interconnecting and selling directly to transmission facilities immediately join in the stream of interstate commerce. Distribution-level wholesales, in contrast, isolated both physically and transactionally from interstate transmission and sale, exemplify Congress's intent in exempting to the states jurisdiction over energy sales not occurring in interstate commerce."[31]

## III. There is no conflict on the face of it between the ISO-NE OATT for Regional Network Service and the proposed treatment of limited producers under RSA 362-A:2-b.

As detailed above, under New Hampshire law, a limited producer is treated as a *load reducer*.[32] ISO-NE's Tariff is clear that "Network Customer's Monthly Regional Network Load

[31] Lindh, Frank and Bone, Thomas, State Jurisdiction Over Distributed Generators (2013). 34 Energy L.J. 499 (2013) (posted with permission of Energy Law Journal), Univ. of San Francisco Law Research Paper No. 2014-03, Available at SSRN: https://ssrn.com/abstract=2368540. *See also The Case Against Direct FERC Regulation of Distributed Energy Resources* by Ari Peskoe of the Harvard Law School Environmental & Energy Law Program published in 2018 available here: https://eelp.law.harvard.edu/unlocking-distributed-energy-resources/#:~:text=The%20Case%20Against%20Direct%20FERC,jurisdiction%20over%20DER%20energy%20sales.

[32] RSA 362-A:1-a, III (emphasis added).

[RNL] shall exclude (i) *load offset* by any resource that is not a Generator Asset . . ."[33] FERC has accepted that load served by unregistered behind-the-meter generation (as well as the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as the Generator Asset) should be excluded from the Monthly RNL, finding that such a division "reasonably reflects each Network Customer's usage of the transmission system and assigns the cost of providing Regional Network Service accordingly."[34] Further, under ISO-NE's OP No. 14, any under 5 MW generating facility that is interconnected below 115 kV may register with ISO-NE but is not required to do so and is not required to participate in any New England Markets.[35] Moreover, power lines below 115 kV are generally considered state distribution facilities. Accordingly, there is no conflict between ISO-NE's Regional Network Service and treatment of limited producers under RSA 362-A:2-b.

## IV. There is no conflict between the ISO-NE OATT for Local Network Service and the proposed treatment of limited producers under RSA 362-A:2-b.

FERC does not have jurisdiction to regulate wholly within-state wholesale sales or retail sales of electricity, as state utility commissions oversee such transactions.[36] The Supreme Court has found that the "[FPA] §824(b) limit[s] FERC's sale jurisdiction to that at wholesale," reserving regulatory authority over retail sales (as well as intrastate wholesale sales) to the States. *New York*, 535 U. S., at 17 (emphasis deleted); see 16 U. S. C. §824(b); supra, at 3. FERC cannot take an action transgressing that limit no matter how direct, or dramatic, its impact on wholesale rates."[37] The DC Circuit Court of Appeals has recently found that "Section 824(b)(1) preserved States' jurisdiction in three categories: (1) within-state wholesale sales (i.e., sales for resale), (2) retail sales of electricity (i.e., sales directly to end users), and (3) facilities used in local distribution, electric generation, only for the transmission of electric energy in

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33 ISO New England OATT, §II.21.2, Effective Date: 9/1/2021 - Docket #: ER21-2337-002. See ISO New England Inc., 178 FERC ¶ 61,086 (2022) (revising the calculation of Monthly Regional Network Load (Monthly RNL) to exclude load served by behind-the-meter generation, which does not participate in the ISO-NE wholesale markets as a Generator Asset, as well as the portions of a Generator Asset utilized to net load at the same retail meter).

34 ISO New England Inc., 178 FERC ¶ 61,086 at P 49 (2022).

35 ISO-NE OP-14, pages 8-9..

36 FERC v. EPSA, 577 U. S. 260 (2016)

37 Id. at 280.

intrastate commerce, or for the transmission of electric energy consumed wholly by the transmitter."[38]

Moreover, Courts have found that States have the authority to prohibit local energy storage resources (ESRs) from participating in the interstate and intrastate market simultaneously: "States retain their authority to prohibit local ESRs from participating in the interstate and intrastate markets simultaneously, meaning States can force local ESRs to choose which market they wish to participate in."[39] Just such a provision is included in LEEPA, which seeks to encourage small scale and diversified resources of supplemental electrical power to lessen the state's dependance upon other sources.[40] In addition, the NHPUC has determined that RSA 362-A:2-a is a valid exercise of state police powers which is not preempted by federal law.[41] Moreover, ISO-NE Tariff Schedule 21 (providing for Local Service) notes that "Retail service is not subject to this Schedule 21 unless specifically provided for in the PTO's Local Service Schedule."[42] Eversource is the transmission provider at the Kingston substation where this limited producer[18] will be located and did not object to this limited producer project being treated as a load reducer relative to their LNS charges. Eversource owns both distribution and LNS transmission in NH under one entity, PSNH. Unitil has a transmission affiliate that provides some LNS and they are the initiator of the first solar limited producer project that will functions as a load reducer for RNS, LNS, and capacity costs. Thus, regulation of limited producers is within the NHPUC's jurisdiction and does not conflict with ISO-NE's Local Network Service provisions. If there ends up being intrastate transmission of power on an transmission owners LNS, such as needing point to point service, then the limited producer or the purchaser, the users of that service, would need to pay any charges due under OATT Schedule 21 as applicable.,

## V. The Joint Utilities misunderstandings about the potential operation of RSA 362-A:2-b limited producer pilots appears to be leading to unfounded concerns about jurisdictional conflicts and impacts on transmission utilities, charges, and rates.

[38] Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 964 F.3d 1177 (D.C. Cir. 2020)
[39] *Id.*
[40] RSA 362-A:1
[41] Re Cabletron Systems, Inc., DR 95-095, Order No. 21,850, 80 NH PUC 620, (October 3, 1995)
[42] See ISO-NE OATT, Schedule 21.

In the Joint Utilities' Response to Commission Information Requests dated April 21, 2023 as well as in their comments at the May 16, 2023 prehearing conference including questions 4 and 5, the Joint Utilities misconstrue the statute to suggest jurisdictional conflicts where none, in fact, exist. In their Response, the Joint Utilities state "there is no money permitted to be collected from retail transmission customers of distribution utilities through their transmission rate mechanisms that could fund or create a pool of credits that could be awarded to any third party. Due to preemption, the focus of the instant proceeding, the Commission cannot authorize the assessment of transmission charges in excess of those set by FERC to fund the LEEP Act's transmission credits." (Response at 10-11.) CPCNH agrees that the PUC has no authority to set transmission rates or charges for FERC regulated transmission services charged to network customers. In the current regulatory structure, the distribution utilities are the network customers that pay transmission charges in the first instance. The PUC should not add to or subtract from such charges, nor second guess FERC on the amount of those charges. Further, the PUC as the state regulatory authority with exclusive jurisdiction over the retail rates of regulated electric distribution utilities (EDUs) must allow the EDUs to recover those costs through retail rates.[43] However, the PUC has complete jurisdiction as to what those charges are called on retail bills and whether other state jurisdictional charges are included with the retail "transmission charge."

As noted at the prehearing conference (Tr. at 20-22) each of the Joint Utilities (Eversource, Unitil, and Liberty Utilities) includes in its retail "transmission" rate state jurisdictional charges as approved by the Commission. Eversource, like the other two, includes a cost of working capital, determined by state jurisdictional lead-lag studies and return on the cost of that working capital. In Unitil's case they do not even present an unbundled "transmission" charge on retail bills, but rather recover their FERC jurisdictional transmission costs as part of a retail "delivery charge" that also includes their costs of owning and operating a distribution system, including what they pay to purchase the output of surplus generation from net metered customers, among other things.

With the PUC's approval of Unitil's proposed investment in a 4.88 MW single-axis PV tracker facility[44], the amortization and return on investment in that "load reducer" generation will

[43] *See* Narragansett Electric Co. v. Burke, 122 R.I. 13, 404 A.2d 821 (1979)

[44] This planned facility meets the definition of a limited producer under RSA 32-A:1-a, III.

be recovered through their delivery charge. The cost to retail ratepayers of this investment is justified by the expectation that the project will save customers even more by avoiding FERC jurisdictional transmission, capacity, energy, and ancillary services costs, plus the value of Renewable Energy Credits (RECs) produced. This is the exact same value stack that RSA 362-A:2-b would enable Community Power Aggregations (CPAs) and Competitive Electric Power Suppliers (CEPS) to access for their customers. In essence, as one part of the retail rate goes down (by the avoided costs from the ISO-NE market & transmission system) another part may go up, but by a little bit less than it would, but for the limited producer,[18] just as RSA 362-A:2-b provides.[45]

Liberty Utilities, like Eversource and Unitil, includes in their retail transmission charge state jurisdictional working capital costs plus certain unrelated property tax reconciliation costs. The PUC (not FERC) has authorized an accounting mechanism called TCAM (Transmission Cost Adjustment Mechanism) which is used to adjust retail rates periodically to account for prior period under or over collections. There is no jurisdictional reason why the PUC could not approve use of the TCAM or a similar mechanism to account for payments to a limited producer for avoided transmission charges, as long as it ensures the ability of the utility to recover FERC authorized transmission charges as well.

Hughes v. Talen followed FERC v. EPSA in 2016 and cites it as a supporting authority rather than in any way contradicting it as previously asserted by Eversource at the prehearing conference in IR 22-061.[46] Perhaps the same Court as decided *EPSA* simply choose not to quote those parts of the EPSA decision that distinguished between interstate and intrastate wholesale market jurisdiction because it wasn't relevant to the case as the generator in questions was a PJM market participant seeking to be compensated in the PJM capacity market as well as receiving

[45] RSA 362-A:2-b, XI(c) provides that a "limited producer or their load serving entity may receive credit or payment for actual avoided transmission charges **based on measurement of exports to the distribution grid <u>at the retail meter point</u> without additional credit for avoided line and transformation losses in the distribution and transmission grids** to provide some sharing of the benefit of reduced transmission charges with other ratepayers who do not participate in such intrastate electricity sales by limited producers." Emphasis added to point out by basing any credit or payment on exports at the retail meter point will mean that all other customers benefit to some extent by a reduction of transmission costs to the extent of avoided transformation and line losses from the provision of an equivalent of power from the bulk ISO New England power market.

[46] IR 22-061, *EDUs: Investigation of Potential Jurisdictional Conflicts Related to Authorization of Pilot Programs Under RSA 362-A:2-b.,* Prehearing Conference Transcript at 10-11

state compensation that supplemented and was ties to the PJM capacity payment.. The decision uses the word "wholesale" 33 times and "interstate" 20 times as qualifier. There is no need to use a qualifier if it there isn't a need to distinguish interstate wholesale from all wholesale. In other words the case had no need to distinguish between interstate and interstate wholesale markets because it was entirely about a state law clearly affecting pricing in an interstate wholesale market under FERC's exclusive jurisdiction.

The Court also rightly recognizes the importance of protecting the States' ability to contribute, within their regulatory domain, to the Federal Power Act's goal of ensuring a sustainable supply of efficient and price-effective energy. As Justice Sotomayor put it in closing her concurring opinion "The Court, however, also rightly recognizes the importance of protecting the States' ability to contribute, within their regulatory domain, to the Federal Power Act's goal of ensuring a sustainable supply of efficient and price-effective energy." A goal New Hampshire shares as it tries to help launch a nascent local transactive energy market in which the buyers and sellers of distributed energy can respond to dynamic market-based price signals as RSA 374-F:1, II calls for.[47]

## VI. The statute enables state jurisdictional retail rate options for how transmission charges paid by the transmission network customers (EDUs in their distribution system operator role) that are not unlike those in Massachusetts and Pennsylvania and PJM.

### MASSACHUSETTS

At the direction of the Massachusetts Department of Public Utilities Commission (MA DPU), the "Extra Large" class T-5 customers in Eversource's Western Massachusetts territory have, apparently since 1997, been charged for transmission based on their individual metered demand at the time of the monthly transmission system peak:

> *Pursuant to D.P.U. 12-97, Rate T-5 customers will be billed on the customer's demand at the time of the ISO New England regional network monthly transmission system peak (the*

[47] '**Competitive markets should** provide electricity suppliers with incentives to operate efficiently and cleanly, open markets for new and improved technologies, **provide electricity buyers and sellers with appropriate price signals**, and improve public confidence in the electric utility industry.'

> *Coincident Peak Demand) for the legacy Northeast Utilities system… The Coincident Peak Demand shall be determined by meter, each calendar month on a one-month lag basis and shall be the customer's coincident 60-minute kilowatt demand.*[48]

More recently, coincident peak transmission billing was extended on an opt-in basis to Eversource's "Large General Service" Rate G-3 customers across the utility's Western Massachusetts territory[49] and Eastern Massachusetts territory — comprised of the Cambridge Service Area,[50] Greater Boston Service Area,[51] and South Shore, Cape Code & Martha's Vineyard Service Area[52] — with identical tariff language, as excerpted below:

> *Customers taking service under this schedule may elect to be billed on the customer's demand at the time of the ISO New England regional network monthly transmission system peak (the Coincident Peak Demand) for the legacy NSTAR Electric system… The Coincident Peak Demand shall be determined by meter, each calendar month on a one-month lag basis and shall be the customer's coincident 60-minute kilowatt demand.*

Massachusetts' expansion of coincident peak transmission billing appears to date back to a 2018 decision in which the MA DPU found that (emphasis added) "**this allocation method** sends a more accurate price signal to customers regarding the true cost of transmission service and **is consistent with how FERC designs transmission rates**, under which NSTAR Electric receives transmission service"[53]

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[48] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 43E, Western Massachusetts Extra Large General Service Rate T-5, at pp. 2-3. Online: https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/43-tariff-ma.pdf?sfvrsn=367cbc2b_3

[49] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 42F, Western Massachusetts Extra Large General Service Rate G-3, at pp. 2-3. Online: https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/21-tariff-ma.pdf?sfvrsn=e57e110f_3

[50] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 21F, Eastern Massachusetts Cambridge Service Area Large General Service Rate G-3, at p. 2-3. Online: https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/21-tariff-ma.pdf?sfvrsn=e57e110f_3

[51] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 13F, Eastern Massachusetts Greater Boston Service Area Large General Service Rate G-3, at p. 2-3. Online: https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/13-tariff-ma.pdf?sfvrsn=290ffbed_3

[52] NSTAR Electric Company, d/b/a Eversource Energy, Tariff M.D.P.U. No. 31F, Eastern Massachusetts Cape Code & Martha's Vineyard Service Area, Large General Service Rate G-3, at p. 2-3. Online: https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/31-tariff-ma.pdf?sfvrsn=fe6e0fff_3

[53] Massachusetts Department of Public Utilities, Docket No. 17-05, Order No. D.P.U. 17-05-B (January 5, 2018), at p. 211. Online: https://www.mass.gov/files/documents/2018/01/26/17-05-B_Order_1-5-18.pdf

and that “pricing transmission service based on a customer’s consumption at the time of system peak rather than based on the customer’s peak, which may not coincide with the system peak, provides a more equitable assignment of cost responsibility.”[54] Consequently, the MA DPU directed Eversource “to evaluate further the expansion of coincident peak transmission billing to NSTAR Electric customers.[55]

**PJM**

In PJM, transmission charges are referred to as “Network Integration Transmission Service” (“NITS”) and are paid for by each "Network Customer", which are defined as entities that are either "participating in a state required retail access program and/or a program providing for the contractual provision of default service or provider of last resort service."[56]

In Pennsylvania, consequently, where unbundling of transmission rates was required pursuant to the state’s Customer Choice and Competition Act, transmission costs have historically been paid for by competitive suppliers on behalf of the retail customers they serve, and paid for by the distribution utility only behalf of the customers that remain on utility default supply.[57]

PJM’s OATT, Specifications for Network Integration Transmission Service Pursuant to State Required Retail Access Programs, requires that (emphasis added):

> *For Network Load within the PJM Region, the Network Customer shall arrange for each electric distribution company (“EDC”) delivering to the Network Customer’s load to provide directly to the Transmission Provider, on a daily basis,* ***the <u>Network Customer’s peak load</u> (net of operating Behind The Meter Generation, but not to be less than zero, unless such generation is separately metered and reported to PJM)****, by bus, coincident with the annual peak load of the Zone as determined under Section 34.1 of the Tariff… The information must be submitted directly to the Transmission Provider by the EDC, unless the Transmission Provider approves in advance another arrangement…* ***For Behind The Meter Generation of a Network Customer that requires metering pursuant to section 14.5 of the Operating Agreement, the Network Customer shall arrange for the Transmission Owner or EDC to provide directly to Transmission Provider information***

[54] *Ibid.*, at p. 212.

[55] *Ibid.*, at p. 213.

[56] PJM OATT, Attachment F-1, Form of Umbrella Service Agreement for Network Integration Transmission Service Under State Required Retail Access Programs, p. 1. Online, beginning at p. 2093: https://pjm.com/directory/merged-tariffs/oatt.pdf

[57] *See* Pennsylvania PUC, Docket No. P-2020-3019522, Order issued 1/14/2021, at p. 34. Online: https://www.puc.pa.gov/pcdocs/1690311.docx

> ***pertaining to such Behind The Meter Generation and the total load at its location as necessary for PJM's planning purposes.*"[58]**

Further, PJM's OATT provides that generation units which deliver energy to load across distribution facilities may qualify as "Behind the Meter Generation" (emphasis added):

> *"Behind The Meter Generation refers to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (**unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities** and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market."*[59]

Thus, in PJM, transmission costs are allocated to competitive suppliers for collection from customers, and utilities are relied upon to administer peak load calculations based on customer demand net of behind-the-meter generation — which, according to the definitions and service agreements in the PJM OATT, can include generation that delivers energy to retail loads <u>across</u> the distribution grid, and can even be counted as reducing the coincident demand of the competitive suppliers' entire customer base below zero (if properly metered and reported as-such).

## VII. The Joint Utilities 3rd question about whether the statute or a PUC order implementing it might impermissibly implicate the treatment of capacity supply obligations does point to an adjacent but more directly implicated potential jurisdictional conflict in t RSA 362-A:2-a, XIII's treatment of the allocation of capacity load obligations, but the problem and potential conflict is avoidable by the terms of the statute.

[58] PJM OATT, Attachment F-1, Form of Umbrella Service Agreement for Network Integration Transmission Service Under State Required Retail Access Programs, pp. 3-4. Online, at pp. 2095-2096: https://pjm.com/directory/merged-tariffs/oatt.pdf

[59] PJM OATT, Common Services Provisions, OATT 1. Definitions, p. 8. Online, at p. 41: https://pjm.com/directory/merged-tariffs/oatt.pdf

How capacity load obligations are to be allocated to meter domains of host participants and in turn to each individual load asset of each load serving entity are detailed in ISO New England is detailed in Attachment A "Load Asset Coincident Peak Contribution" of the Manual for the Forward Capacity Market (FCM) Manual M-20, which is attached hereto as ATTACHMENT CPCNH-1.[60] This appears to be a document approved by the NEPOOL Markets Committee, rather than specifically by FERC or as part of a tariff or Market Rule.[61] M-20 calls for the Host Participant[62] to apportion the overall "Metering Domain's Coincident Peak Contribution" to each individual retail customer's contribution to peak load. Where the customer has hourly interval metered data used for load settlement "the individual customer's contribution to peak load ***should*** be based upon the hourly metered usage" consistent with cost causation principles. (However, the use of "should" rather than "shall" in this sentence suggests that this is not intended to be a mandatory requirement.) If an individual customer's usage is negative at peak load, then their contribution to the peak would be negative as well, in that they reduce the peak load from what it would be without their exports to the grid.

However, RSA 362-A:2-b, XII prohibits negative capacity tags for individual customers. If not settled on hourly interval load data, then "the individual customer's contribution to peak load shall be based upon the hourly estimated value determined using the relevant retail regulatory authority's customer load profiling techniques." Here, a modification of NH's load profiling techniques might be a means to modify the allocation of capacity tags to account for exports of limited producers in the pilot in manner consistent with M-20.

The Coalition agrees that the end result of any allocation of capacity obligations or "tags" necessarily must be that "[t]he sum of all the Load Assets being reported by each Host Participant will equal the total Metering Domain's Coincident Peak Contribution for each

[60] Revision 27, effective April 6, 2023, full document available here: https://www.iso-ne.com/static-assets/documents/2023/04/manual_20_forward_capacity_market_rev27_2023_04_06.pdf.

[61] *See, for example,* Memo to NEPOOL Markets Committee dated 3/1/23 requesting a vote on proposed revision to Manual M-20 found here: https://www.iso-ne.com/static-assets/documents/2023/03/a03_mc_2023_03_07-09_manuals_m-20_m-28_obsolete_language_clean-up_voting_memo.pdf.

[62] Defined in the ISO-NE glossary as "A market participant (or governance participant as defined in a Participant Agreement) transmission or distribution provider that reconciles the loads within the metering domain with ISO Operating Procedure No. 18, Metering and Telemetering Criteria, compliant metering" found here: https://www.iso-ne.com/participate/support/glossary-acronyms#g.

settlement."[63] The overall capacity load obligation assigned to each LSE/market participant is inherently a FERC jurisdictional wholesale rate that can't be second guessed or blocked from recovery by the PUC where it is part of EDU default service rates, but how that exactly how that gets charged to and recovered from each individual retail customer, as opposed to the LSE market participant, in the rates of CPA and CEPS serving load at retail is beyond both FERC's and the PUC's jurisdiction and is rather a function of a free and competitive market with customer choice.

The question remains whether it is within state authority for the Commission to require EDUs to a assign to an LSE load asset a "reduced capacity supply obligation" resulting from a limited producer's export of "power to distribution grid at the annual hour of coincident peak demand on which capacity supply obligations are incurred" where "such exports reduce overall capacity supply obligations from what they would otherwise be absent such exports to the grid," which they undoubted do by reducing the amount of load of the metering domain as measured (or estimated) at the wholesale meter point where the distribution grid connects with transmission grid (PTF). So, what happens today when distributed generation or storage (not registered with ISO-NE as a market participant) exports to the grid at the annual hour of coincident peak demand? It becomes part of "unaccounted for energy" that, along with line losses, is used to adjust retail loads to match in sum the amount of power delivered over and metered off the PTF. Without such exports retail loads would typically be adjusted upwards for line losses. However, if the amount of exports to the grid exceeds such line losses, and there is no other unaccounted for energy, then such exports could result in retail loads appearing to be more than the amount of power measured at the distribution/transmission grid interface, which in fact they could be because they are being supplied by these distributed generation and storage facilities.

RSA 362-A:2-b, XII is based on the idea that where such exports can, in fact, be accounted for, as limited producers must have hourly interval metering[64], their benefit in reducing the need for capacity from ISO-NE bulk power market should be credited to the load asset that creates such benefit, consistent with cost causation principles. However,

[63] ATT CPCNH-1 : ISO NE Manuel M-20, p. A-1.

[64] RSA 362-A:2-b, X.

accepting that there may still be an unresolved jurisdictional issue here, the text of RSA 362-A:2-b, XII provides a means to avoid such conflict. Noting that EDUs must petition the PUC to approve each pilot in conjunction with a CEPS or CPA[65] and that the first sentence of Section XIII ends with the phrase "such reduced capacity supply obligations shall be assigned to the LSE serving such limited producers **as approved** by the commission" (emphasis added) then the pilot proposers could request that such assignment be disregarded for purposes of complying with ISO-NE M-20 until such time as a change may be approved to accommodate NH's statute by the NEPOOL Markets Committee and ISO New England as necessary. Further, the remaining provisions as to how individual capacity tags may be modified are permissive with the use of the term "may" rather than being a statutory mandate, so could be waived by the LSE as a pilot participant.

An important question for the future remains: is metered power exported to the distribution grid by a customer-generator or limited producer, such as Unitil's Kingston solar limited producer project, or in Liberty's Battery pilot, truly "unaccounted for energy" in this digital day and age when it is being accounted for in utility cost-benefit analyses, VDER studies, PUC decisions, and potentially in load settlements pursuant to RSA 362-A:9, II and XXI(a)? Is it an appropriate price signal supporting competitive markets to completely socialize the peak load reducing value of DERs when they actually perform on the annual system peak by not accounting for their contribution as a load reducer relative to the ISO NE capacity?

## VIII. None of the activities allowed by RSA chapter 362-A would require a utility to violate the Transmission Operator Agreement or require a recalculation of any ISO-NE open access transmission tariff (OATT).

"The ISO's primary Transmission Operating Agreement (TOA) with New England transmission owners, among other things, provides the ISO with operating authority over their commercial transmission facilities. Transmission owners that are signatories to this agreement

[65] RSA 362-A:2-b, VII

are recognized under the ISO Tariff as participating transmission owners (PTOs)."[66] The TOA enables ISO-NE to be the transmission provider under the OATT and is not affected in any discernable way by any of the activities allowed by RSA 362-A and there is no basis to think of any of the activities allowed by RSA 362-A would cause a utility to violate such agreement. Section 2.05 concerns "Connection with Non-Parties" but refers to large or small generating facilities that interconnect directly Transmission Facilities, which is not at issue here. While some activities under some parts of RSA 362-A might conceivably entail generators that could connect directly to the transmission system, Limited Producers are, by definition, generators or storage facilities that are only interconnected to the state jurisdictional distribution grid, as are customer-generators that participate in net metering pursuant to RSA 362-A:9.

It is not apparent what "recalculation of any ISO-NE open access transmission tariffs" might mean, but to the extent it means an amendment to the ISO-NE OATT, none is needed to accommodate activities allowed by RSA 362-A, much less RSA 362-A:2-b. To the extent it might refer to recalculation of the rates charged under the OATT, there is nothing about the activities allowed under RSA 362-A:2-b or the chapter as a whole that would trigger such recalculation. The rates for transmission and other ISO-NE services charged under the OATT are routinely adjusted as load deviates from forecast, so limited producers and any of the over 180,000 net metered PV systems in New England that function as load reducers are just part of the mix.

## ILLUSTRATIVE POTENTIAL PILOTS

Commissioner Chattopadhyay at the prehearing conference indicated his interest in examples comparable to the type and treatment of distributed generation contemplated by RSA 362-A:2-b. (Transcript at 27-28)

Current examples of the type and form of generation contemplated would be the VT (Vermont) SPEED ("Sustainably Priced Energy Enterprise. Development") feed-in tariff program and NHEC's 3rd party battery ownership (2.5 MW) where NHEC can dispatch the battery to reduce coincident peaks, to reduce transmission charges and annual forward capacity

[66] *Transmission Operating Agreements*, ISO NEW ENGLAND, https://www.iso-ne.com/participate/governing-agreements/transmission-operating-agreements.

market obligation for their system as a whole, and whereby ISO-NE can also dispatch it as an ATRR; but otherwise the battery owner buys the power output at wholesale (intrastate – and they didn't ask FERC permission) for resale to their retail customers and allows the owner of the battery to arbitrage hourly prices whenever they want (with a special retail rate that charges them hourly RT LMP + losses when they charge and pays them RT LMP + avoided losses. The VT SPEED is (or was) a feed-in tariff that was created pursuant to state law and a consensus settlement involving VT EDUs, both public and investor owned, VELCO transmission provider, clean energy advocates, VT Public Service Department and other stakeholders that was approved by the VT Public Service Board in Docket No. 7533 in 2009. A few key excerpted pages from that order are ATTACHMENT CPCNH-2 and list of project is ATTACHMENT CPCNH-3.

Examples of proposed projects that could be eligible for pilot proposals: 1) 1 MW LFGTE (Landfill Gas to Energy Systems) project being developed by City of Lebanon (as owner) for sale of power to Lebanon Community Power (technically a City enterprise but operated through CPCNH JPA) located behind a substation transformer with a minimum load of > 5 MW, so said project should never cause a reverse power flow onto the transmission grid. This project could currently qualify for group net metering as an alternative; slated to go online next year, 2) more than 3 MW of dual axis trackers that City of Lebanon is close to issuing an RFP for, to be owned by city on city land (distributed sites, some without native load). 100% of the output could be used to offset balance of city loads not already served by BTM 3rd party PV. As proposed, it could be a limited producer project with City retail sales to itself though CPCNH. As planned this project could also qualify for municipal group net metering, but could be expanded to up to just under 5 MW with 3rd party sites and owners selling to CPCNH for resale to meet loads within the same local distribution utility territory; and 3) a single axis tracker project similar to the project that was recently approved by PUC for Unitil to develop (and rate base) with the same proposed value stack as DOE, OCA and PUC embraced and approved in DE 23-044.

***Respectfully submitted*** this 23rd day of June 2023

***Community Power Coalition of New Hampshire***

Clifton Below

***by CPCNH Chair Clifton Below, duly authorized***