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Via Electronic Mail Only

Dianne Martin, Chairwoman
New Hampshire Public Utilities Commission
21 South Fruit Street
Concord, NH 03301-2429

RE: IR 20-166, Investigation into Compensation of Energy Storage Projects for Avoided Transmission and Distribution Costs, Additional Reply Comments for City of Lebanon

Dear Chairwoman Martin:

Thank you for the opportunity to provide additional reply comments in this investigation on behalf of the City of Lebanon, as provided for in the Commission's Secretarial Letter of June 24, 2021. These are the first comments filed for the City in this investigation and are focused on the two topics called out in the Secretarial Letter and how they impact all the questions before the Commission (or Department of Energy, as the case maybe) namely: (1) the impact of pending changes to the Open Access Transmission Tariff relating to load reconstitution; and (2) the relevant impacts of Senate Bill 91, if enacted. First is a summary of the general impact of these two new developments and then specific application to the questions originally posited in the Order of Notice in this investigation and by RSA 374-H:2. II.

(1) <u>Impact of Pending Change to New England OATT Relating to Load Reconstitution</u>

On July 1, 2021, the Participating Transmission Owners (PTOs) Administrative Committee and ISO New England Inc. filed with FERC proposed "Modifications to Monthly Regional Network Load Calculation in the ISO-NE Transmission, Markets and Services Tariff."[1] Each transmission customer's share of Regional Network Load (RNL) is their share of the

[1] Available at: https://www.iso-ne.com/static-assets/documents/2021/07/pto_ac_monthly_rnl_filing.pdf.

regional load measured at the hour of highest demand, coincident peak, in each month of the year, so there is an RNL calculation for each month. Regional Network Service (RNS) costs for the embedded costs of the Pooled Transmission Facilities (PTF) are allocated to load at the wholesale level based on share of RNL The current tariff states that RNL "shall not be credited or reduced for any behind the meter generation." However, in practice this has been mainly applied to the approximately 2,000 dispatchable "Generation Assets" registered with ISO-NE that happen to be connected to the distribution grid or local transmission and not the PTF, so the retail load they offset at system peak is "reconstituted" and added into the RNL calculation. However, most of the more than 180,000 distributed solar power generators in the region are not registered as Generation Assets and any load they might serve hasn't typically been measured by the utilities, much less subject to load reconstitution. (Id at 9.)

The PTOs propose to modify the Tariff to exclude the reference to behind-the-meter generation and instead state that each:

"Network Customer's Monthly Regional Network Load shall exclude (i) load offset by any resource that is not a Generator Asset, and (ii) load offset by the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as the Generator Asset."

As the PTOs explain: "a 'Generator Asset' is defined in the Tariff as 'a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.'" (Id at.7.) ISO New England Operating Procedure, OP-14, provides the technical requirements for Generators and other resources to register with and participate in ISO-NE markets. Battery storage systems meet the criteria for qualifying as a Generator Asset, depending on size. In short, every generator exporting power to the New England grid (regardless of whether FERC jurisdictional interstate transmission or state jurisdictional distribution grid) at peak output of 5 MW or more must register with ISO-NE as a Generator Asset. If they are smaller than 5 MW and interconnected to a state jurisdictional distribution grid (under 115 kV), they don't have to register and instead will be treated as a "load reducers" for all ISO-NE market purposes. Storage or generation from 1 to 5 MW may opt to register as a Generator Asset. This clarified treatment of distributed generation and storage facilities allows such DERs in the 1 MW to 5 MW range have a choice of not participating ISO-NE markets and being treated as a load reducer for transmission cost allocation, remaining more purely under state jurisdiction OR they can register with ISO-NE and participate in FERC jurisdictional interstate wholesale markets.

The value and benefits of the former option are recognized by the PTOs and ISO New England in their joint filing to FERC where they state the following:

- "Clarifying the Tariff to specifically allow for the netting of the behind-the-meter generation to reduce network load will provide clarity for all participants and align the Tariff with the inherent incentives of those participants to net or offset monthly network load. This will in turn have several resulting benefits." (p. 3)
- "First, the proposed Tariff revisions more closely align the allocation of transmission costs among Network Customers with current transmission planning practices in New England where needs are typically based on net load. Under the proposed Tariff revisions, Network Customers that are able to reduce their peak network load through the use of behind-the-meter generation will likely incur less transmission costs than Network Customers who do not reduce their peak network load through the use of those resources." (p.3)
- "Reducing the costs to those who reduce their peak demand using behind-the-meter generation will enhance the benefit of behind-the-meter generation. This will further encourage the development and deployment of those resources in New England." (p.3)
- ". . . clarifying the Tariff to exclude or net from the Monthly RNL small behind-the meter generation, consistent with current practice for calculating Monthly RNL, would require no implementation hurdles and would level the playing field for all Network Customers. The incentive for a Network Customer is to reduce their Monthly RNL, and thus their RNS rate, through the use of behind-the-meter and onsite generation. The proposed revisions would align the Tariff with this inherent incentive, and provide a consistent methodology for all Network Customers in accordance with the available and required metering." (p. 11)
- "The netting approach would also more closely align with current transmission planning practices in New England, where needs are typically based on net load.32 Further, participants that rely to a lesser degree on the New England integrated transmission system to serve load through their use of behind-the-meter generation will likely pay less for the use of that system. This will align the charges for the use of New England's integrated transmission system to a Network Customer's use of that system, consistent with the principle of cost causation.33 [FN: The cost causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits. *See, e.g., Ass'n of Regulatory Util. Comm'ners. v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007); *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992")."]" (p. 12)
- ". . . generation resources not registered to participate in the New England wholesale markets are treated as load reducers for the purposes of calculating the load used for market settlement. Clarifying that behind-the-meter generation also serves as a load reducer in the determination of network load would harmonize the treatment of behind-the-meter generation that does not participate in the New England markets in each relevant component of the Tariff."

So, the central impact of the clarification of the OATT is to recognize that distributed storage and generation that doesn't register as a Generation Asset to participate in ISO New England markets does function as a load reducer, reducing both load for ISO-NE wholesale market settlement, as well RNL and RNS transmission cost allocation. RNL, or something very close thereto, is also used to allocate costs for Local Network Service (LNS) which a smaller portion of the FERC jurisdictional interstate transmission grid that only serves portions of region, so this change in the OATT should also be recognized in cost allocation of LNS.

On the other hand, storage that does participate in ISO-NE markets will not function as a load reducer and will not reduce RNL and thus will not reduce or avoid transmission cost allocation, although it might still have value in avoiding transmission or distribution costs to the extent it functions as a location specific cost-effective non-wires alternative to a transmission grid investment.

(2) Relevant Impact of SB 91, if Enacted

There are several impacts of SB 91, if enacted into law, that are particularly relevant to this investigation. First and foremost, the current definition of "Wholesale electricity markets"[2] is amended to add six words: "or may operate pursuant to RSA 362-A:2-a." Those 6 words expand the wholesale markets to be considered in the question of "[h]ow to compensate energy storage projects that participate in wholesale electricity markets for actual avoided transmission and distribution costs." With the OATT clarification discussed above, it should be clear that energy storage projects that participate in ISO NE markets will not avoid RNS or LNS transmission cost (rate) allocation, so no compensation for such would be appropriate. However, recognizing an intrastate wholesale electricity market that may operate pursuant to RSA 362-A:2-a under state jurisdiction as a possibility allows the Commission to consider how such distributed generation or storage can function as a load reducer and realize actual avoided transmission cost allocation to New Hampshire consumers.

It is often said, and misunderstood, that FERC has jurisdiction over wholesale electricity markets. However, the Federal Power Act at 16 U.S.C. §824(b)(1) only grants authority to FERC to regulate "the sale of electric energy at wholesale in interstate commerce." That federal law states that "electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof." Hence, in the words of the US Supreme Court "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

[2] RSA 374-H:1, XIV: "XIV. "Wholesale electricity markets" means any energy, capacity, or ancillary service market that ISO-New England operates."

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 wholesale 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."[3]

RSA 362-A:2-a, most recently amended in 1998 by the same very same legislation[4] that created net metering, RSA 362-A:9, and terminated utility obligation to purchase power from limited producers, provides that: "A limited producer of electrical energy shall have 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." Hence, RSA 362-A:2-a enables a limited producer to sell under state jurisdiction to up to 3 other purchasers that could either be retail customers or intra-state wholesale customers (for resale within the state). In is in that this context that storage could participate in an intrastate wholesale market and still function as a load reducer and hence avoid or reduce transmission cost allocation.

SB 91 will repeal and reenact Chapter 374-H and in doing so add a whole new section, to be numbered "2," that requires adoption of rules to enable interconnection of storage systems in New Hampshire incorporating principles enumerated in the legislation, including mechanisms for compensation of energy storage by non-utilities for any actually avoided transmission or distribution charges. Obviously, this investigation can now help inform the development of such rules and resulting tariffs. Leaving aside the question of avoided distribution charges, for storage functioning as a load reducer relative to ISO-NE actual avoided transmission charges becomes fairly readily ascertainable, if the storage facility is equipped with an interval meter that can show its production and/or exports to the distribution grid at the hour of monthly coincident peak used to calculate RNL and RNS and LNS charges.

Now I turn to how these 2 new developments combine to inform the detailed considerations of this investigation.

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[3] FERC v. EPSA, 577 U. S. ____ (2016), p. 17. For additional legal context see also City of Lebanon testimony for SB 91 in NH House, 4/19/21, attached hereto.

[4] Chapter 261:5, NH Laws of 1998, found here: http://www.gencourt.state.nh.us/legislation/1998/HB0485.html.

A. Establishment of Accurate and Efficient Price Signals

RSA 374-F:1, in calling for development of competitive markets for both wholesale and retail electricity services states that "[c]ompetitive markets should . . . provide buyers and sellers with appropriate price signals." Accurate and efficient price signals for energy storage projects are ultimately dynamic cost causation price signals that are transparent to both supply and load. Some commentators have pointed to FERC Order 2222 that seeks to enable DERs that are too small to directly participate in ISO-NE markets to participate as part of an aggregated group of DERs as the way for DERs to realize their full value stack. It is through ISO-NE markets that dynamic market values are established for energy, capacity, ancillary services, as well as transmission services. Although the revenue requirement for transmission is not particularly dynamic, the cost allocation is, reflecting a dynamic hour of coincident peak demand that is not known for each month until after the fact. A great deal of work has gone into the development of ISO-NE markets, including incorporating demand response to some extent, and that work continues to evolve with Order 2222.

However, FERC Order 2222, as well past efforts to enable retail demand response to participate in ISO-NE markets, can also be seen as a work-around for the failure of states to enable translation of ISO NE wholesale market and transmission price signals to retail on a time-varying basis. The key to accurate and efficient prices, also known as optimal price formation, is to enable load and supply, including DERs, to be able to respond to the same, or at least similar, temporal price signals. However, retail load, and hence DERs generally, such as those participating in net metering, are heavily insulated from temporal price signals. Transmission is an extreme case in point.

At the ISO-NE level transmission rates, although designed to fully recover a revenue requirement based on historic embedded investment costs, costs are recovered based on a fairly extreme marginal cost price signal – based on share of a single hour of monthly coincident peak. This coincident peak demand charge is then translated to retail load, including net metered customer-generators, as a flat per kWh charge, with no temporal significance, except perhaps in the most general way to rate classes. The marginal cost price signal of demand at coincident peak is efficient, as it simulates the way a healthy competitive market would work. The attached "City Comments on Update to NH Energy Strategy, 6/27/21" goes into more detail on appropriate and efficient price signals, but the point here is that NH public policy can much better link retail price signals to those from ISO-NE and also provide similar marginal price signals for overall coincident peak demand of the distribution system as fundamentally most every aspect of electrical infrastructure needs to have the capacity to serve coincident peak demand and new increments of capacity are typically more expensive than embedded costs for similar capacity.

To enable such efficient price signals does require interval metering typically provided by AMI systems, so enabling access to such metering, on at least an opt-in basis, is another to key to accurate and efficient price signals at the individual account level.

B. Compensation for Avoided T&D Costs in a Manner that Provides Net Savings to Consumers.

Energy storage projects that participate in ISO-NE wholesale electricity markets should only be eligible for avoided transmission costs to the extent they are part of a cost-effective non-wires alternative (NWA) to a particular transmission investment. By cost-effective I mean costs that are more likely than not to be less than the traditional wires solution. Energy storage projects that only participate in intrastate wholesale or retail markets and thus function as load reducers for RNL calculations should be eligible to be compensated financially, in the form of a payment or financial credit, that is no more than the actual avoided cost of transmission charges. This can be achieved by measuring the actual exports to the distribution grid of an energy storage system during the monthly hour of peak when RNS and LNS charges are determined and giving credit based on that retail meter measurement at the actual rate charged for each month, which can only be determined after the fact, thus with some lag. Because the actual reduction in RNL will be somewhat greater than the exports to the grid at the retail meter point, due to line and transformation losses, there should be some savings for other consumers.

A helpful way to think about the equity in this is to imagine a perfect world in which every retail customer or customer-generator within a given meter domain, served by one LSE, has interval meters and are charged both as a group and individually for transmission based on their share coincident peak demand for each month. In other words, the ISO-NE charge is passed through directly to customers. If a customer with storage zeroed out their load at coincident peak in a given month, then they would not be charged anything for transmission for that month. If they exported 100 kW to the grid at a system peak and assigned those exports to an account with a 100 kW load at system peak, then that account would also zero out transmission charges for that month. That 100 kW exported to the grid would physically offset the nearest loads with minimal actual line losses, so that 100 kW at the retail meter might actual avoid on the order of 105 to 107 kW of demand at the PTF boundary where RNL is calculated due to actual avoided line and transformation losses. Hence, absent such granular "demand" charges and credits, continuing to charge all load at the meter a flat transmission rate/kWh and then credit storage or DG for most but not quite all avoided transmission costs from the transmission revenue account based on exports to the distribution grid should result in about the same cost to other load and benefits that would accrue in the "perfect world" scenario.

The real material net savings to consumers will come from the value of shifting loads off coincident peaks, generally avoiding expensive new investments for capacity that will only rarely be used. In other words, price signals that help shift net load off coincident peaks will improve load factors and asset utilization rates, meaning more kWh will bear the fixed capacity cost for a system sized to meet coincident peak demand with safety factor, lowering the cost per kWh. That is where the substantive savings to all consumers is to be found, by spreading the fixed capacity costs over more kWh by incenting load to avoid coincident peaks where is it feasible and cost-effective, such as with storage and flexible loads such as most vehicle charging.

Regarding avoided distribution costs, any storage, whether participating in ISO NE markets or not, should be eligible for consideration as distribution NWAs. In addition, cost recovery of distribution costs could be much more based on a temporal marginal cost price signal, such as by making most demand charges based on share of coincident peak demand, like with transmission. This can also be done through volumetric TOU rates such as devised in Liberty's battery pilot in which distribution costs were allocated to TOU periods in proportion to the amount of coincident demand that occurs in those periods.

C. How Best to Encourage Both Utility and Non-Utility Investment in Storage

Providing access for both utility and non-utility storage projects to cost causation based marginal cost price signals would encourage both. Some commentators in this investigation, particularly EEI and Eversource, have contended, in effect, that distribution utilities, because of their regulated monopoly status, are uniquely situated to best realize the full value stack of storage projects. However, if they can figure out the value stack for regulatory purposes such as for inclusion in distribution rate recovery as in Liberty's investment in BTM battery storage, then those values should be translatable to appropriate price signals for market-based investment and innovation. Unitil helps make the case that the role of the utility as distribution system operator, with visibility and dispatch capability for DERs, is entirely compatible with market- based price signals, competition, and innovation in the provision of electricity services, as is called for by RSA 374-F. See further the discussion of the "Shared Integrated Grid" in the City's comments on the state energy strategy.

The City's comments on the state energy strategy also point to comments by ISO New England's Director of Advanced Technology Solutions on the need for the development of "local energy markets" for DERs regulated by the states to interface with and complement ISO-NE bulk power markets and do so in a way that captures the value of avoided costs in the ISO-NE markets. Progress on Grid Modernization as called for in PUC Order No.26,358 in IR 15-296, the Data Platform settlement in DE 19-197, and administrative rules for Community Power Aggregations called for in RSA 53-E will all encourage both utility and non-utility investment in energy storage.

D. Establishing a Bring Your Own Device Program

RSA 374-H:2 as will be amended by SB 91, essentially calls for rules to implement BYOD opportunities for energy storage.

E. Recommended Statutory Changes

To enable energy storage projects, as well as distributed generation not participating in net metering, to receive appropriate compensation for avoided transmission and distribution costs while also participating in wholesale markets, including within state sales to load serving entities for resale, RSA 362-A: 2-a should be updated and amended along the lines of SB 91, Part IV as passed by the Senate.[5] A further refinement of that legislative text is attached as "PROPOSED REWRITE of RSA 362-A: 2-a and Relevant Definitions." This is text that was developed after the House Science, Technology, and Energy Committee heard SB 91, in negotiations involving the Committee Chair, Rep. Vose, and other stakeholders, and subsequently presented to the committee at a work session. Ultimately the majority of the Committee decided to further study some issues raised concerning limited producers rather than proceeding at this time with the update.

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[5] Available at: http://gencourt.state.nh.us/bill_status/billText.aspx?sy=2021&txtFormat=html&v=SA&id=936.

The rationale for such an update to RSA 362-A: 2-a is largely explained in my attached testimony on the bill and comments on the State Energy Strategy. The text makes it clear that a generator or storage system can only sell power as a limited producer under state jurisdiction if they are not participating net metering nor in ISO-NE markets as a generator or network resource 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." ATRRs are a specialized category for storage that allows ISO-NE to call upon them for certain regulation functions without requiring them to register as a Generation Asset. Storage only participating as an ATRR with ISO NE can still function as a load reducer for all other purposes, including RNS.

Fundamentally the question of how transmission and distribution costs are charged at retail and how any DERs might be compensated for avoided transmission costs, assuming they are not participating in FERC jurisdictional ISO-NE markets, is a state jurisdictional decision under the purview of the New Hampshire PUC, as long as full recovery of those costs as charged through the OATT is enabled by the state.

Yours truly,

Clifton Below

Clifton Below,
Assistant Mayor, City of Lebanon

ATTACHMENTS TO COMMENTS