STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 21-3883-RULE

Proposed creation of Vermont Public Utility Commission Rule Concerning Energy Storage	

VERMONT DEPARTMENT OF PUBLIC SERVICE REPLY COMMENTS

The Vermont Department of Public Service ("Department") hereby submits its comments following the workshops held on January 13 and 20, 2022, and in response to the questions posed by the Vermont Public Utility Commission ("Commission") in a procedural order issued on February 16, 2022. For convenience, the Commission's questions have been reproduced before the Department's responses.

I. Simplified siting

Question a. Decommissioning Plans: What information should the Commission require for decommissioning plans? Should decommissioning plan requirements vary by project size, footprint of the site and/or other factors? What special considerations should the Commission make for decommissioning of storage systems in particular? Should the Commission include decommissioning requirements in the new storage rule or amend existing Rule 5.900 to expressly apply to storage facilities?

To ensure that storage facilities are appropriately dismantled and disposed of at the end of their useful life, and to ensure that sites are fully restored once facilities are no longer in use, there is a need for decommissioning requirements which provide sufficient guidance and promote adequate funding. In short, the goal is to protect the public interest while providing predictable and reasonable obligations for developers. To that end, the Department suggests the existing framework of Commission Rule 5.900 as the best starting point for consideration.

Rule 5.900 applies to "all electric generation, electric transmission, and natural gas facilities that are or become subject to the jurisdiction of the [Commission] pursuant to 30 V.S.A. § 248."[1] As the Commission has noted, decommissioning requirements for storage facilities could be imposed by amending Rule 5.900 or by including decommissioning provisions in the storage rule. While the location of the rule is ultimately less important than the requirements

[1] Commission Rule 5.901.

themselves, it may be advisable to maintain a single rule incorporating decommissioning requirements for all resources. It is the Department's view that the structure and substance of Rule 5.900 should be adapted to apply to storage facilities, either within Rule 5.900 itself or as a template for equivalent provisions in the storage rule.

Before discussing storage-specific considerations, it may be useful to outline the general implications of following a Rule 5.900 framework. Under this approach, storage decommissioning plans should resemble those used in other § 248 petitions: plans should provide sufficient information to demonstrate that they are consistent with the requirements of Rule 5.904(A) or (B) (or similar provisions adapted for storage). The Department suggests that plans required for smaller installations could mirror the plans required under the net-metering rules, which must "provide for the removal and safe disposal of project components and the restoration of any primary agricultural soils."[2] Plans for larger installations should likewise describe decommissioning activities, with the addition of a decommissioning cost estimate and irrevocable standby letter of credit or alternative form of financial security.[3]

With that blueprint in mind, the Department offers thoughts on the following additional considerations, particularly as they relate to battery storage facilities: (1) decommissioning requirements for facilities of all sizes; (2) requirements based on project size or other factors; (3) information provided in decommissioning plans; and (4) systems under 100 kW.

1. *Decommissioning requirements for facilities of all sizes*

A universal concern in the case of battery energy storage is the management and disposal of waste and hazardous materials. For systems of all sizes, the Department recommends a provision addressing the need to transport and recycle/dispose of these systems in accordance with best practices and all applicable state and federal waste management regulations. As the relevant laws and rules are also under the purview of other state or federal agencies, and are

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[2] Commission Rule 5.107(C)(12); *see also* Commission Rule 5.904(A) ("Facilities . . . shall be removed once they are no longer in service, and the site shall be restored to its [prior] condition . . . to the greatest extent practicable.").
[3] *See* Commission Rule 5.904(B).

likely to change rapidly in the coming years, it may be most effective to create a general provision on the subject.

2. *Requirements based on project size or other factors*

Consistent with the idea of adapting Rule 5.900 (through amendment or otherwise) to apply to storage, the Department suggests that the core requirements for storage facilities should be equivalent to those for generation facilities. In other words: "Facilities . . . shall be removed once they are no longer in service, and the site shall be restored to its condition prior to installation of the facility to the greatest extent practicable."[4] Under Rule 5.904, this requirement is currently applicable to generation facilities with a capacity of 150 kW and greater, while facilities over 500 kW must also provide a cost estimate and letter of credit (or a Commission approved equivalent). Cost estimates and accompanying financial assurances will be equally important for larger storage facilities, but the question is whether the current size categories in Rule 5.900 are appropriate.

A definitive answer to this question will require further information, and input from other stakeholders. The Department does not yet have a full understanding of the cost implications for decommissioning battery energy storage facilities, particularly those under 1 MW in size. Certainly, for storage facilities at or above 1 MW, the Department would recommend applying the requirements of Rule 5.904(B) for additional cost information and funding. Experience has shown that the estimated cost for decommissioning these systems can approach the costs associated with solar systems of a similar capacity and may exceed them. Though battery systems typically occupy a fraction of the footprint required for a solar array of similar capacity, the removal and recycling or disposal of battery systems entails different logistical challenges and cost drivers, with one simple example being the sheer weight of the materials involved. Thus, while overall footprint may not be particularly relevant in setting decommissioning requirements for storage, the capacity and energy of the system should be considered.

At the small end of the spectrum, it may be appropriate to adjust the 150 kW threshold specified in Rule 5.904(A), for generation, down to 100 kW for storage. This would align with

[4] Commission Rule 5.904(A), (B).

the 100 kW threshold for storage facilities subject to § 248 review.[5] Whether it is necessary and reasonable to require decommissioning plans at this scale is something that should be explored further in consultation with the relevant stakeholders.

3. *Information provided in decommissioning plans*

The Department suggests that decommissioning plans for storage facilities should be consistent with the substantive requirements of Rule 5.900 or similar provisions adapted from the same. At a minimum, plans should provide an overview of decommissioning activities related to the removal and safe disposal of project components and the restoration of the site to its former condition. For battery systems, this would include handling and recycling/disposal of battery modules, battery enclosures, electrical and other associated equipment, and site infrastructure such as concrete pads, along with site restoration activities. All work should be done in accordance with the applicable environmental and waste management regulations.

In addition, the Department recommends soliciting information regarding any available "take-back" and/or recycling programs offered by the battery manufacturer or other entities. In cases where a turnkey arrangement is not available, the Commission may wish to see additional details in the plan or impose appropriate conditions.

In line with the structure of Rule 5.900, plans should include a cost estimate when required, along with a letter of credit or alternative form of financial security.

4. *Systems under 100 kW*

Storage facilities under 100 kW will not be subject to review under 30 V.S.A. § 248, therefore it is important to note that without an amendment, Rule 5.900 will not apply. Rule 5.900 applies only to "facilities that are or become subject to the jurisdiction of the [Commission] pursuant to 30 V.S.A. § 248."[6] If the Commission wishes to address decommissioning for all storage facilities within Rule 5.900, it could simply extend the rule to cover "all energy storage facilities as defined in 30 V.S.A. § 201(4)" and add provisions for these

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[5] 30 V.S.A. § 248(u) (effective December 31, 2022).
[6] Commission Rule 5.901.

small systems. The alternative is to include requirements within the storage rule, which could be accomplished as outlined in the response to Question e. below. In the Department's view, the primary concern for decommissioning of systems under 100 kW is to ensure that components are recycled and/or disposed of in accordance with best practices and all applicable waste management regulations.

Question b. Simplified Siting for Storage other than Batteries: 30 V.S.A. § 248(u) requires the Commission to "establish a simplified application process for energy storage facilities subject to this section with a capacity of up to 1 MW, unless it establishes a larger threshold by rule." 30 V.S.A. § 201(4) defines an energy storage facility as "a stationary device or system that captures energy produced at one time, stores that energy for a period of time, and delivers or may deliver that energy as electricity to the grid for use at a future time."

Given the definition of energy storage facility in 30 V.S.A. § 201(4) and the requirement for a simplified application process in 30 V.S.A. § 248(u), can the Commission limit the type of storage eligible for simplified siting, by rule or otherwise, to battery storage? If not, how can the Commission best address the simplified siting of technologies other than battery storage?

Considering the statutory language cited by the Commission, the Department recommends a simplified application process be made available to all energy storage facilities with a capacity up to 1 MW. However, different degrees of simplification may be warranted for battery vs. non-battery energy storage technologies, given differences in footprint and other characteristics. In its Initial Comments, the Department recommended three siting categories for storage projects subject to 30 V.S.A. § 248:

A. Storage projects between 100 kW and 1 MW, located within existing structures: registration process akin to that available to rooftop solar registration process under Rule 5.100
B. Storage projects between 100 kW and 1 MW, **not** located within existing structures: 30 V.S.A. § 248(j) or like process, some conditionally waived criteria
C. Storage projects over 1 MW and up to 5 MW: 30 V.S.A. § 248(j) or like process, no conditionally waived criteria

All three categories represent a "simplified process," when compared with the full 30 V.S.A. § 248 process. Therefore, any of the three could be applied to non-battery storage technologies up to 1 MW in size, and still provide a simplified process. It may be that no changes are necessary to the categories – in other words, that they are appropriate for battery and non-battery technologies as is. At least for the foreseeable future, in the Department's opinion, non-battery storage technologies are likely to be large in scale and therefore not located within existing structures.[7] This would place them in siting category B or C, enabling greater process and more review criteria as warranted.

To ensure more process than is currently contemplated under category A, the Commission may wish to instead make it explicit that non-battery storage technologies are not included in that category. It is also important to acknowledge that the Department's initial proposal for facilities up to 5 MW to be included in a simplified process was based on its experience with battery storage facilities between 1 and 5 MW. For non-battery storage, which encompasses a broader range of technologies, the Commission may find it appropriate to maintain the 1 MW cap which currently exists in statute. Both considerations above could be addressed by modifying the categories as follows:

A. *Battery* storage projects between 100 kW and 1 MW, located within existing structures: registration process akin to that available to rooftop solar registration process under Rule 5.100;
B. *Battery* storage projects between 100 kW and 1 MW, **not** located within existing structures, *and all non-battery energy storage between 100 kW and 1 MW*: 30 V.S.A. § 248(j) or like process, some conditionally waived criteria;
C. *Battery* storage projects over 1 MW and up to 5 MW: 30 V.S.A. § 248(j) or like process, no conditionally waived criteria;
D. *Not Eligible for Simplified Siting: Battery storage projects over 5 MW, and non-battery storage projects over 1 MW* (full process under 30 V.S.A. § 248, no conditionally waived criteria).

As Vermont gains experience with deployment of various storage technologies, it may be appropriate to extend the registration process under category A based on new considerations, or conversely to require a more involved process based on certain parameters. This speaks to the broader need for flexibility in a rapidly changing landscape, and the Department supports adaptability in the Commission's storage rules to the extent that it can be achieved within the bounds of procedural requirements and without compromising robust public and stakeholder engagement.

[7] *See, e.g.*, *Technologies of Energy Storage*, ENERGYSTORAGE.ORG, https://energystorage.org/why-energy-storage/technologies/.

Question d. Fire Safety[8]: If the Commission were to adopt the Department's proposal that most criteria under 30 V.S.A. § 248 be waived for systems sited within existing buildings, would there be a regulatory incentive to develop projects within existing structures? If so, does this pose any broader concerns for public safety due to fire risk and how can the Commission best address those concerns?

The first part of the Commission's question is not easily answered at this stage in the growth of the energy storage sector. If it transpires that the permitting process under § 248 is the primary limiting factor in developing storage facilities, then there is an incentive to pursue the most simplified path to approval. However, it may be the case that there are factors outside the § 248 process which reduce or completely counteract that incentive. Examples might include limitations from other permitting or certification requirements, constraints in equipment size and packaging or other technical obstacles, and the availability of suitable and cost-effective sites. These factors will be better understood over time, and input from other stakeholders on the subject may prove invaluable. Nonetheless, for purposes of this discussion it is prudent to assume that the Department's proposal would provide some degree of incentive for the development of storage projects within existing structures.

With respect to how the Commission could best address any concerns for public safety due to fire risk, the Department does not have a response at this time but is continuing to research the questions, including consulting with various authorities. The Department respectfully requests that the Commission grant the Department additional time to submit a complete response. At present, the Department is planning to provide a response by March 31, 2022.

[8] The Commission's Question c. was directed at the Agency of Natural Resources, therefore the Department proceeds to Question d.

Question e. Small Systems (under 100kW): Should the Commission require systems under 100 kW to register with the Commission under a general permit? In the alternative, should small systems simply be required to meet basic requirements (interconnection, fire safety, and decommissioning for example) without registering with the Commission?

Under Act 54, storage facilities under 100 kW will not be subject to 30 V.S.A. § 248 and therefore will not need a CPG under that Section.[9] Nonetheless, it will be important to ensure that smaller systems exporting to the grid meet basic requirements for system stability and reliability, and public health and safety. The legislature has provided authority for the Commission to set rules for "storage facilities of all sizes," including requirements for "electrical and fire safety, power quality, interconnection, metering, and decommissioning."[10] While the Commission may be in the best position to determine the most effective and efficient approach, the Department offers the following thoughts for the Commission's consideration.

As a general matter, the Department recommends a rule requiring storage systems under 100 kW to be installed and operated in accordance with certain technical specifications. These could include applicable codes and standards for electrical and fire safety, along with decommissioning and other requirements. While not a direct comparison, an example of this type of approach can be found in past versions of Commission Rule 5.100, specifically the provision regarding interconnection for net metering facilities 150 kW or less. In that example, facilities 150 kW or less were required to follow the Net Metering Technical Specifications included in an Appendix A, which contained applicable codes, interconnection requirements, and other guidance.[11] In the case of storage under 100 kW the "Appendix A" approach could include all applicable requirements, or could be used for a specific subset of codes and standards not covered by Rules 5.500 and 5.900 in combination with directives to follow applicable interconnection procedures and decommissioning requirements.[12]

[9] *See* 30 V.S.A. § 248(u) (effective Dec. 31, 2022).
[10] 30 V.S.A. §§ 8011(a), (b)(2).
[11] *See, e.g.*, Commission Rule 5.111 (adopted 2013), https://puc.vermont.gov/sites/psbnew/files/doc_library/5100-PUC-nm-adopted-2013_0.pdf; Commission Rule 5.100, Appendix A (2016), https://puc.vermont.gov/sites/psbnew/files/doc_library/rule-5100-appendix-a-tech-specs.pdf.
[12] The latter may be preferable, particularly in the case of interconnection.

Regardless of how the requirements for these smaller storage facilities are set forth, it is the Department's view that the Commission should have access to basic information regarding the type and size of the systems installed, the location of the installations, and the owners, along with a certification that the installation meets applicable requirements. For utility-owned systems the rule could simply require internal record-keeping of compliance information, to be made available to the Commission upon request or reported periodically. For systems owned by others, a minimal registration requirement may suffice.

While the suggestions above represent one approach, there may be several adequate solutions to choose from in accounting for storage systems under 100 kW – with varying levels of oversight by the Commission. Other stakeholders may have important perspectives to share on this subject, and the Department remains open to alternatives that provide the necessary safeguards.

II. Aggregations and interplay between owners, operators, and utilities

Question f. Ownership and Cumulative Impacts: To assess the cumulative impact of energy storage systems being added to existing generation, several commenters suggested that the Commission should use an amendment process for the existing CPG at the site. When a proposed energy storage facility installer is not the CPG holder of the generation component of the paired system, should the storage project receive a separate CPG? If so, how should the Commission consider cumulative impacts?

The Department envisions four possible scenarios where an energy storage facility is proposed in close proximity to existing generation. These variations relate to the entity proposing the storage facility ("storage applicant"), the CPG holder for the existing generation ("existing CPG holder"), and the links if any between the two systems:

1. Storage applicant and existing CPG holder are the same, and the systems are separate (operate independently)
2. Storage applicant and existing CPG holder are different, and the systems are separate (operate independently)
3. Storage applicant and existing CPG holder are the same, and the systems are operationally linked
4. Storage applicant and existing CPG holder are different, and the systems are operationally linked

Scenarios (1) and (2) may not be considered "paired systems" within the meaning of the Commission's question, however it is worth noting that a situation could arise where a storage facility is proposed close to existing generation without being operationally linked. In those cases, it may not be appropriate to amend the existing generation CPG, or the conclusions and conditions incorporated therein. If the two systems are operationally separate, the Department recommends that the storage project receive a separate CPG. As with any CPG proceeding, the impacts from the proposed project should be evaluated under the applicable criteria, including interconnection considerations, with reference to the characteristics and constraints of the existing site and surrounding infrastructure. The Department expects that this would also allow for appropriate review of relevant impacts to natural resources criteria but defers to the Agency of Natural Resources' expertise on that subject.

Scenarios (3) and (4) represent the more likely situations, where storage is proposed to be added or "paired" with existing generation such that there is a modification of the preexisting facility because systems are operationally linked. In scenario (3), where the storage applicant is the same entity as CPG holder for the existing generation, the Department has suggested that an amendment to the existing CPG is the best approach to assess all potential impacts of the added storage. It is the Department's view that a CPG amendment is also the preferable approach for scenario (4), when the storage applicant is a different entity from the existing CPG holder.

Adding this type of "paired" storage to existing generation will modify the operations of the generation facility, whether the entities responsible for the two projects are the same or not. In either case the conclusions and conditions incorporated in the existing CPG for the generation component should be reexamined considering the proposed modification. The amendment process will allow for a full assessment of potential impacts from the new storage component, along with any impacts created by the pairing of the two systems. An amendment is also a logical process for such review because a later pairing of storage with existing generation is essentially a modification of the underlying CPG. Under this approach, the entity responsible for the storage could become a co-holder of the amended CPG.

In scenario (4), which appears to be the focus of the Commission's question, there is also the possibility (however remote) for to a situation which should be avoided: an applicant seeking or obtaining approval of paired storage without the consent or involvement of the CPG holder for the existing generation. This scenario is problematic from both from a practical and legal perspective, as adding storage implies modifying the existing generation and therefore affecting the rights and obligations of the existing CPG holder. In the Department's view, the CPG amendment process is the best approach to minimize the potential for adverse outcomes, but it must require a showing of the consent, and if necessary, the active participation of the existing CPG holder from the outset.

Given the variations in ownership and operations identified above, the Department suggests that there is a need to clarify and clearly define the meaning of "paired system" or "paired storage." Further, there is a need to evaluate how the Commission and other parties can accurately determine whether an amendment is required, based on the characteristics of the project and not simple assertions in the petition. From the Department's perspective, it is also important to avoid a situation where a CPG holder for existing generation is made an unwilling host for paired storage or is compelled to participate in proceedings before the Commission to prevent such an outcome. The Department encourages additional engagement and consideration on these issues, including the question of what specific requirements or restrictions may be appropriate.

<u>Question g. Proposed Codes and Standards: Of the standards identified by the Department in their comments of December 16, 2021, (pp. 6-7), which should the Commission adopt? Should the codes and standards that the Commission adopts vary based on size, complexity, use-case, or other factors?</u>

Much like Question d., above, the Department respectfully requests additional time to provide a complete answer. The proper adoption of codes and standards is an important issue and the question of whether the adopted codes and standards should have varied applicability for certain configurations and scenarios is nuanced. As such, the Department aims to follow up with a fuller response by March 31, 2022, for this question as well.

Question h. 30 V.S.A. § 231 CPG: In its comments of December 16, 2021, the Department suggests that the Commission should consider the following issues (among others) in a review of aggregated resources for a § 231 CPG (emphasis added):

- Provisions to ensure the load impacts of storage are appropriately reviewed by the interconnecting utility and do not negatively impact *ratepayers*;
- Provisions to ensure participation of the resource in the aggregation and the aggregation in the wholesale markets does no harm to the distribution utility or *ratepayers*.

Does FERC Order 2222 limit the Commission's jurisdiction in considering the impact of aggregated resources on ratepayers? Does the Commission have the authority to deny an aggregation CPG based on the impact that the aggregation may have on ratepayers?

At this stage in the implementation of Order 2222, the Department finds little clarity on the roles and responsibilities of Relevant Electric Retail Regulatory Authorities ("RERRAs"), in Vermont's case, the Commission, when it comes to overseeing aggregations. The full implications of Order 2222 remain to be seen, as the FERC and the ISOs continue to develop their approach and respond to emerging issues. One example of this uncertainty relates to whether Order 2222 preserves the ability of RERRAs to prohibit aggregators from bidding retail customers' demand response resources into the wholesale markets (the "demand response opt-out"). The demand response opt-out was established in Order 719, and after three decisions on the scope of the opt-out, FERC determined that it would remain available under Order 2222.[13] Even so, the FERC has opened an inquiry seeking comments on the idea of eliminating the opt-out altogether.[14] It appears that the inquiry is still ongoing.

Given all that remains to be ironed out between FERC, the ISOs, and RERRAs moving forward, it is perhaps most prudent to highlight areas where the state role has been expressed more clearly and to proceed on that basis. In Order 2222, FERC confirmed that RERRAs will remain responsible for the interconnection of individual distributed energy resources ("DERs")

[13] *See* Order No. 2222, 172 FERC ¶ 61,247, at ¶ 59 (2020) ("[T]his final rule does not affect the ability of [RERRAs] to prohibit retail customers' demand response from being bid into RTO/ISO markets by aggregators."), https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf; Order No. 2222-A, 174 FERC ¶ 61,197, at ¶¶ 22, 28 (2021) (setting aside in part the relevant conclusion of Order 2222), https://www.ferc.gov/sites/default/files/2021-03/E-1.pdf; Order No. 2222-B, 175 FERC ¶ 61,227 at ¶¶ 26, 29 (2021) (reinstating the conclusion of Order 2222 but suggesting that the issue will be considered further).

[14] *See generally Notice of Inquiry re Participation of Aggregators of Retail Demand Response in Markets*, 174 FERC ¶ 61,198 (2021).

seeking to join a wholesale aggregation.[15] FERC also noted the availability of a small utility opt-in, and opportunities to combat double-compensation.[16] As for the broader role of RERRAs, Order 2222 includes the following guidance:

> [P]ossible roles and responsibilities of relevant electric retail regulatory authorities in coordinating the participation of distributed energy resource aggregations in RTO/ISO markets may include, but are not limited to: developing interconnection agreements and rules; developing local rules to ensure distribution system safety and reliability, data sharing, and/or metering and telemetry requirements; overseeing distribution utility review of distributed energy resource participation in aggregations; establishing rules for multi-use applications; and resolving disputes between distributed energy resource aggregators and distribution utilities over issues such as access to individual distributed energy resource data.[17]

Importantly, FERC went on to require "that any such role for relevant electric retail regulatory authorities in coordinating the participation of distributed energy resource aggregations in RTO/ISO markets be included in the RTO/ISO tariffs and developed in consultation with the relevant electric retail regulatory authorities."[18] On February 2, 2022, ISO-NE filed proposed revisions to its Transmission, Markets and Services Tariff ("Tariff") to comply with Order 2222 and associated directives (the "Compliance Proposal").[19] The Compliance Proposal includes provisions addressing the role of RERRAs with respect to distributed energy resources' participation in distributed energy resource aggregations ("DERAs"), summarized by ISO-NE as follows:

> All six states within ISO-NE's footprint have state interconnection rules and requirements for DERs, and these interconnection procedures will be relied upon by the ISO to ensure reliable operation of individual DERs in a DERA. As noted above, the Tariff revisions proposed in the Compliance Proposal direct DER Aggregator/Host Utility disputes to the RERRAs to the extent they have applicable processes. In addition, the Tariff revisions require that the DER

[15] *See* Order No. 2222, 172 FERC ¶ 61,247 at ¶ 294 (2020) ("[T]his final rule in no way prevents state and local regulators from amending their interconnection processes to address potential distribution system impacts that the participation of distributed energy resources through distributed energy resource aggregations may cause.").
[16] *See id*. ¶¶ 64, 162.
[17] *Id*. ¶ 324.
[18] *Id.*
[19] *See* ISO-NE, *Revisions to ISO New England Inc. Transmission, Markets and Services Tariff* (Feb. 2, 2022) [hereinafter "Compliance Proposal"], https://www.iso-ne.com/static-assets/documents/2022/02/order_no_2222_filing.pdf.

> Aggregator share DERA registration data with RERRAs to the extent they request to receive such information. Also, as noted above, the DERA metering requirements rely on state-approved metering standards for individual DERs participating in a DERA.[20]

Within the Compliance Proposal, the specific rules for distributed energy resource aggregations to participate in the New England markets are found under Section III.6 of the Tariff. As explained by ISO-NE, registration and coordination provisions "require[] Host Utilities (or their agents) to review each DER for relevant safety, reliability, and eligibility criteria, including any RERRA-established criteria that may be put in place."[21]

At this point in time, the tools available to the Commission under Order 2222 are most clear in the areas of interconnection, safety and reliability, dispute resolution, and information gathering. The Department anticipates learning more as ISO-NE's Tariff undergoes review and approval along with tariffs in other regions, as other states develop procedures for DERs in aggregations, and as mechanisms develop for operational coordination with utilities. It is also worth noting that ISO-NE's Compliance Proposal requests an effective date of November 1, 2026 for the rules under Section III.6 of the Tariff, which address distributed energy resource aggregations.[22] ISO-NE suggests that this date will, in part, "allow RERRAs to conduct any necessary rulemaking processes to coordinate the participation of DERs in both retail and wholesale markets, to review Host Utility implementation plans to the extent necessary, and to allow for implementation of RERRA orders by Host Utilities."[23]

The operations of aggregated energy storage devices do implicate potential impacts to ratepayers. The extent to which FERC Order 2222 may circumscribe the ability of the Commission to regulate this aspect of storage as part of a wholesale DER aggregation is not yet clear. Therefore, at a minimum, the Department recommends that the Commission begin to collect information on storage aggregation attributes and monitor the prevalence and impacts of storage aggregations over time. This will help inform any determination as to whether additional regulatory touchpoints on storage aggregation operations are warranted and feasible. The

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[20] *Id*. at 38.
[21] *See id*. at 29.
[22] *See id*. at 43.
[23] *Id*.

Department also notes the potential to address certain impacts with existing or emerging tools, including Rule 5.500 and the procedures by which utilities will review DERs and aggregations.

Question i. Aggregation Amendments: If an already existing aggregation seeks to amend its aggregation, what opportunity does the utility have to assess system stability, system reliability, and transmission effects of the proposed amendment? How can Commission processes and rules ensure that utilities can review amendments and change existing interconnection agreements (if necessary)?

FERC Order 2222 appears to anticipate the need for utilities to review the impacts of an aggregation based on modifications or amendments to the aggregation over time. When discussing coordination between ISOs and utilities to study system impacts related to aggregation, FERC stated:

> As the individual distributed energy resources in an aggregation may change over time, we cannot discount the possibility that the electrical characteristics of the aggregation will change significantly enough to require restudy. In practice, we expect that modifications to the list of resources in a distributed energy resource aggregation could occasionally indicate changes to the electrical characteristics of the distributed energy resource aggregation that are significant enough to potentially adversely impact the reliability of the distribution or transmission systems and justify restudy of the full distributed energy resource aggregation; therefore, RTOs/ISOs and distribution utilities may perform such aggregation restudies if necessary. Similarly, while the interconnections of distributed energy resources seeking to participate in RTO/ISO markets as part of a distributed energy resource aggregation would be subject to state or local interconnection procedures, we believe that coordination between RTOs/ISOs and distribution utilities . . . should ensure that RTOs/ISOs have the information that they need to study the impact of the aggregations on the transmission system. In general, where needed, such studies of the impact of an aggregation as a whole on the transmission system should be the only aggregation-related studies that the RTO/ISO needs to undertake.[24]

This suggests that the utility/ISO review process will include opportunities to assess stability and reliability impacts associated with changes to an aggregation.

ISO-NE's Compliance Proposal provides further insight, as it lays out a detailed process for "Host Utility" review of an aggregation. This includes an "initial notification phase" by the

[24] *See* Order No. 2222, 172 FERC ¶ 61,247, at ¶ 99 (2020), https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

aggregator to ISO-NE and the Host Utility, with a description of the aggregation and the requirement that "each DER comprising the DERA must have an executed interconnection agreement, where state rules require the DER to have an interconnection agreement, or if an interconnection agreement is not required, the DER Aggregator must provide information needed to conduct any studies that may be necessary to identify distribution system impacts of the DERA."[25] Host Utilities then have 60 days to review each DER in the proposed aggregation for "relevant safety, reliability and eligibility criteria, including any RERRA-established criteria that may be put in place.[26] Additional steps follow. The Compliance Proposal also specifies a process for DERs to be added or removed from an aggregation: Host Utilities will again have 60 days to review the changes, in part to allow "the time, where necessary, for Host Utilities to restudy an entire DERA to determine whether such changes produce reliability impacts across the entire DERA footprint, i.e., whether the changes introduce interactions between DERs that were not present for the original DERA composition."[27]

As to how the Commission's rules and processes should mesh with, or bolster, ISO-NE's process and enable appropriate utility review, or adjustments to interconnection agreements, the Department suggests that input from implicated utilities may provide essential context to evaluate this question. Utilities will be asked to navigate both the regional and state-level processes and requirements, and an understanding of the key considerations from their perspective will be invaluable.

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[25] *See* Compliance Proposal at 29, https://www.iso-ne.com/static-assets/documents/2022/02/order_no_2222_filing.pdf.
[26] *See id*.
[27] *Id*. at 39.

DATED at Montpelier, Vermont, this 11th day of March, 2022.

Respectfully Submitted,

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