9/11/2023 RES Stakeholder Advisory Group - Meeting 4: Summary of Issues/Questions and Response

These notes include summary of issues highlighted and PSD/SEA Response to Issues (where there is one) or plan to get response. Additional context that may not have been provided originally, has been provided in these notes.

These notes do not go into detail on methodology slides that did not raise issues/questions.

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Agenda:

The core of the agenda for this meeting was to walk through the benefit cost methodology slides that were presented by SEA. These notes highlight questions or issues raised during the meeting. **SAG members should provide feedback if your question wasn't answered, or you have further follow ups. Issues are identified in bold below. Some of the responses include both discussion at the meeting and PSD/SEA thinking following.**

Interconnection Costs and Storage

SEA noted there are two types of interconnection costs considered in the study: site-specific upgrades paid for at the time of construction by interconnecting Distributed Generation ("DG") (included in the cost of resources to meet the RES, as these costs would be passed through to utilities in the costs to purchase the power) and those not paid for by the interconnecting DG (where strategic, system-wide upgrades necessary to meet requirements to purchase more in-state renewable generation beyond what the current system could handle and that cost more than a single project can bear, could theoretically be planned for and made by utilities, and potentially socialized to either ratepayers or taxpayers.

Based on current practice, almost all interconnection costs (both at the distribution and transmission level) fall under the first category (that is, they are paid for by interconnecting generation). Distribution utilities are required to provide sufficient resources to serve load (those costs show up in rates) - not generation, so additional costs caused by the need to interconnect generation are assigned to that DG. At levels of DG Vermont has reached or is approaching, it may not be economically feasible for interconnecting DG to bear these costs. Whether to require utilities (and thus ratepayers) to pay for upgrades to accommodate more distributed generation is a major policy question.

There is more work to be done to determine if and whether transmission and distribution costs should be assumed to be socialized, and if so, how much. Still, the modeling incorporates estimates of "transmission integration costs" to account for future socialized costs. It was noted that we still need to consider whether regional/national studies of interconnection costs are applicable in Vermont, where we have a significantly higher penetration of DG than in most states.

The Generation Scenarios Planning Tool was highlighted as a potential option for evaluating interconnection costs of different in-state generation (Tier II) requirements. Development of a methodology using this tool could be done by the Department as an input that could take the place of default values or become part of a range of options; the tool could alternatively be used to estimate interconnection costs of different scenarios once results (i.e., amounts of in-state generation needed to meet different scenarios) are available. Given current timing, the latter analysis is much more likely. This may require some help from the Distribution Utilities (DUs) and VELCO. The Department expects to facilitate additional discussion on this point.

Specific interconnection costs in specific sub-regions of Vermont are not likely to be modeled in this study – as the broad study is more of a statewide assessment.

1. **Issue/Question: Scenarios and their costs and benefits do not account for scenarios of future load flexibility (including battery storage) in Vermont.**

An assessment of the implications of aligning generation and load on a more granular basis than annually (e.g., quarterly, monthly) is one of the components of this analysis. An estimate of the amount of storage that may be required to achieve hourly matching (for example) is an output of this analysis, but not the costs and benefits of those amounts of storage. This will allow us to answer the question of how much load flexibility (including storage as one tool) might be necessary to smooth generation profiles from a power supply perspective, relative to hourly load.

The study does not answer the question: "Given varying levels of storage penetration, what are the additional costs (if any) required to integrate DG." Additional understanding of how the storage would be used, the impacts to the unit (for example, would additional cycling – charging and discharging – reduce the lifetime of the battery, changing its economics?) and to other benefit value streams (the aforementioned power supply benefits that currently are used to justify installation of storage) are not within the scope of the analysis.

With regard to avoiding localized constraints on the system – the Department *may* be able to use information from this study in order to estimate levels of load/generation flexibility in specific locations throughout the state that would be able to avoid distribution constraints, but it will be important to understand the economic impacts of storage - specifically using it for generation constraints rather than to avoid power supply charges. It is unlikely that a storage facility can be assumed to acquire full value from both of these use cases.

The study will provide an estimate of distributed generation located in Vermont, and estimate resulting interconnection costs. As a follow up, it is possible that additional work could be performed to understand the amount of interconnection costs that could be avoided, with those investments in load and generation flexibility solutions.

Further Action/Process: The Department welcomes continued conversation to best use the study results to inform consideration of addition analysis on investments in load flexibility, including storage.

<u>Capacity Accreditation and Coincidence with Peaks</u>

SEA Explained the valuation of capacity benefits (See Slide 12/13), which is different between capacity that are cleared in the forward capacity market and resources that are not.

2. **Issue/Question: The uncleared capacity in the chart on slide 13 does not track with the value that utilities see from avoided charges from behind-the-meter resources. In addition, the value of the capacity market seems very high (identifying an error in the original Avoided Energy Supply Costs [AESC] Report).**

Slide 13 portrayed a societal impact of uncleared capacity. Uncleared capacity (that is, capacity not bid into the Forward Capacity Auctions) has the effect of reducing future ISO-NE load forecasts, in turn, reducing the Installed Capacity Requirement set by ISO-NE, which in turn sets the amount of capacity that is solicited in Forward Capacity Auctions and paid for by all New England electricity customers. However, as a reduction to load such capacity does have an impact on Vermont *ratepayers* and will be accounted for in the ratepayer impact analysis.

The error in the original AESC Report has been identified and adjusted for. A potential reason that the prices looked high in the chart is related to the anticipated change in the Forward Capacity Market that lowers the capacity coincidence of many resources – resulting in an offsetting effect to the value as seen in an increase expected market price.

Further Action/Process: N/A

<u>Benefit – Price Effects vs Price Suppression</u>

Clarification that Price Effects are expected to decay because of demand elasticity. The AESC Report explains this and other reasons.

3. **Issue/Question: There were concerns raised that the model will not adequately capture price effects because utilities own entitlements to power, where significant reductions in demand (through behind the meter resources) or high generation days would cause lowering of prices that actually increase costs to ratepayers (when utilities then have to sell that excess power at the lower prices than they purchased it). This is particularly true on high generation days.**

Supply would drive down prices for capacity, but not necessarily for energy in all hours because of the above described issue. The AESC price suppression values account for Vermont utilities being hedged. However, they do not account for the granularity of the issue above.

Further Action/Process: Because the price effects are relatively small per kWh, this impact is likely to be small. The hourly load and generation profiles will allow for review of scenarios net interchange (i.e. the net of a utilities supply and demand). If such net interchanges are seen to be higher, or the price effect impacts are significant, this can be reviewed.

<u>Transmission and Distribution (T&D) Benefits</u> (Slides 14-16)

The presentation pointed to the Commission's adoption of a T&D value for benefits that was developed by the AESC for use as a regional transmission benefit of avoided load, but adopted in Vermont to apply to both transmission and distribution benefits. This value is one of the options for considering T&D benefits of distributed generation in this study. The PSD went on to discuss the transmission landscape in Vermont – and describing its understanding of the Commission's decision: Vermont has no large load growth-related T&D investments, as evidenced by the Long Range Transmission Plan and the Vermont System Planning Committee process of evaluating non-wires alternatives for load growth-related projects under Docket 7081, which has identified no relevant upgrades. Moreover, reductions in Vermont's load have no appreciable impact on the transmission investments being made in other parts of New England, largely being made in population centers in SW Connecticut and Boston areas. That said, the value is likely to be greater than zero, where long-term investments are pushed out somewhat (they aren't even showing up on utilities' radars) and smaller components of the grid may be able to be sized differently or delay/avoid upgrade or replacement altogether.

4. **Question/Issue: Concern was expressed about relying on the Commission, Commissioners who are not engineers.**

The PSD responded that the Commission is well versed in taking testimony from expert witnesses, including engineers, and adjudicating engineering issues such as this one. In the absence of studies supplying alternative values specific/relevant to Vermont T&D, the values adopted by the Commission are the best available for use in the study. Stakeholders are welcome to provide relevant studies for review. One potential option is to introduce a range of values.

Further Action/Process: Continue to consider a value, or a range of values associated with T&D benefits.

5. **Question/Issue: Does the T&D value diminish over time? Should we expect any avoidance of transmission and distribution benefit, particularly for the upper end of scenarios that have the most significant Tier II (Vermont-based smaller generation)?**

The SAG member expressed skepticism that the upper end of the range would be able to avoid investments, where significant quantities of DG are located in Vermont and could have little impact on load. The current plan for distribution benefits is to identify the top 100 hours of load, and look at projected production in those hours, applying coincident factor associated with the generation profile. If the load is not shaped to peak at the same time the generation is available, then the application of any value would be limited. For transmission benefits, the same coincidence applied to capacity value will be used.

Further Action/Process: N/A – The proposed approach is intended to capture alignment of resource production with system needs taking into account future changes in load patterns; it does not separately account for additional factors which may lead to declining marginal benefits.

6. **Question/Issue – How are we accounting for any upgrades that distribution generation might pay for – for example transformer upgrades that are paid for by solar installations?**

It was described in the last meeting that there is no value assumed as a benefit for future grid upgrade costs in the model. Research is thin on this subject. In Massachusetts, regulators appear to be moving toward a pro-rata distribution of upgrade costs, determining how much should be socialized and how much should be borne by the interconnecting DG. Many utilities across the country argue there is little benefit to those outside the interconnecting DG. It was noted that we might be able to capture a societal benefit if larger studies were done into siting near load.

However, there are situations where there is likely to be some value to ratepayers from these investments. For example, if a residential solar project upgrades a distribution transformer, then that same transformer would not then need to be upgraded again when a customer installs, for example, an electrification measure. In the territories of utilities who would pay for the cost, or part of the cost, of this transformer to encourage an electrification measure, the interconnection of distributed generation benefits ratepayers as a whole. While the research is thin, a **value of zero would be incorrect, where the investments provide a value greater than zero.** The Department invites stakeholders to provide values and justification for their application in the Vermont context, and expects to propose a value to SAG members to include in the study.

Future Action/Process: - The PSD is conducting further research into a potential value, for benefits associated with distribution upgrades caused by the interconnection of DG (and paid for through interconnection costs), and propose to the SAG a non-zero value. The SAG should provide any research, values, and justification it wishes to be considered to the Department as soon as practicable.

Reliability

7. **Question/Issue – There was concern expressed that the local impacts of distribution reliability will not be explicitly examined.**

The presentation explained a statewide societal value of lost load. Due to data, time, and resource constraints, this study will not be able to focus on individual areas of the state. It isn't clear if there is a desire for this study to support the need for socializing distribution impacts of particular solutions across the state. That type of decision is beyond what this study can inform.

Future Action/Process: N/A

Non-embedded GHG and NOx reduction Benefit (slide 18)

There was discussion about using the Social Cost of Carbon as adopted in the AESC, which is the same value that the PSD has advocated for and utilized for several years in the societal test applying to energy efficiency and utility resource cost decisions. The Vermont Climate Council subsequently adopted this value for use to evaluate societal impact of resource choices.

8. **Question/Issue: Should this analysis use a societal cost of emissions different from that adopted by the Vermont Climate Council?**

Social Cost of GHG Emissions/Carbon: The supplemental study value produced for MA was ultimately rejected by their regulators for use in energy efficiency and MA currently uses the same value Vermont uses (See Docket D.P.U. 21-120 through D.P.U. 21-129). VT Energy Action Network summer interns conducted a review of the latest research on the societal cost of emissions which can be found here. If updated avoided emissions values are finalized and/or adopted by the Federal Interagency Working Group, the Vermont Climate Council will be the venue for decisions on whether to adopt those recommendations/updates for policy evaluation purposes.

Future Action/Process: N/A

9. **Question/Issue: Will the model consider regional emissions reductions?**

Yes, the model will consider regional emissions reductions from the marginal resource expected to be avoided. The use of existing generators to meet RES requirements will not count as emissions reductions.

Future Action/Process: N/A

Water Use

10. **Question/Issue: The water use slide is deficient, because while it addresses water benefits, it does not address offsetting water costs, such as storm water runoff and flooding**

The model is expected to report gallons of water saved, but not put a dollar value on that water. There is no specific data to quantify impact, but costs should be qualitatively addressed. The Department is reviewing additional information provided by SAG members, and is considering including qualitatively both water impact benefits and costs (no dollar values for either).

Future Action/Process: The Department and SEA are reviewing information provided and will look to assess qualitatively consider all water impacts.

Miscellaneous

11. **Question/Issue Who is the Brattle Group working for, how does that relate to this modeling, are they doing something different or is it part of this?**

Brattle Group is working for the Joint Fiscal Office on behalf of the RES Legislative Working Group. They are expected to use the outputs from SEA work to input into a macroeconomic analysis to evaluate impacts of scenarios on indicators such as jobs and state Gross Domestic Product.

12. **Will you provide a summary sheet of the assumption inputs?**

More context to slide 5, such as cites and links for benefit cost streams will be provided so that the review can look them up.

- Providing all the assumptions in a succinct format would be a challenge. When draft results are delivered, key assumptions will be included in the presentation for review.