The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

MEMORANDUM

TO: Electronic Distribution List in D.P.U. 20-75

FROM: Katie Zilgme, Hearing Officer

RE: April 13, 2022 Technical Conference Staff Notes on Participant Discussion

DATE: June 15, 2022

CC: Mark D. Marini, Department Secretary

I. INTRODUCTION

On April 13, 2022, the Department of Public Utilities ("Department") conducted a Technical Conference via Zoom ("Technical Conference") to further our investigation in the present docket of a Long-Term System Planning Program. Prior to the Technical Conference, on April 6, 2022, I issued a Hearing Officer Memorandum announcing logistics and a detailed agenda. In the agenda were several discussion topics, including:

1. Distribution Company Process for Long-Term System Planning Analysis ("Analysis Process");
2. Program Process;
3. Straw Proposal Revisions;
4. Program Eligibility Criteria; and
5. Minimum Filing Requirements

During the Technical Conference, the Department received constructive comments from stakeholders on each of the topics outlined above. At the same time that stakeholders were contributing to discussion and providing comments at the Technical Conference, Department staff were taking notes ("Staff Notes").[1] By this Memorandum, the Department releases the Staff Notes set forth in Section II below for public view with the intent to incorporate the Staff Notes into the Administrative Record. Reference to the Staff Notes will inform the Department in the issuance of the initial policy Order establishing a framework for a Long-Term System Planning Program ("LTSPP").

II. STAFF NOTES

Discussion 1: Distribution Company Analysis Process

What requirements should be uniform, if any, across the Distribution Companies? Should the Distribution Companies' Analysis Processes be completely uniform?

Comments:

- **Massachusetts Department of Energy Resources ("DOER")**: Clean energy targets are consistent among territories so it would be more consistent to collaborate statewide with stakeholders, including DOER.
- **Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil")**: In general, it should be consistent, but the Analysis Process should be different/varied among electric distribution companies ("EDCs"). As far as timing and frequency there should be consistency.
- **Massachusetts Office of Attorney General ("AGO")**: In reaction to Chair Nelson's remarks, the quicker we can act here (before 7/31/2022) the more effective we can be in creating a system that benefits everyone getting ahead of legislation that would put us in a tighter spot. Forecasting stage and data sources should be utilized/adopted across all EDCs, common methodology for hosting analysis adopted across the board. Wants to establish a LTSPP committee.
- **Pope Energy**: Agrees with AGO. Hasn't seen anything about other distributed generation ("DG") (such as wind) and how that would affect distributed energy resources ("DER") across the state. Says there is little difference between DG

[1] These Staff Notes were finalized within one Business Day of the Technical Conference for accuracy.

and transmission; the EDCs should be making recommendations to enable transmission.

- **Interstate Renewable Energy Council ("IREC")**: Uniformity is important, particularly the underlying assumptions in forecasting. Such as potential or negative impact of solar on the grid.
- **Northeast Clean Energy Council ("NECEC")**: The Climate Plan should be the corner stone for how we are looking at the horizon.
- **Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid")**: Agrees with common process for LTSPP. Also agrees with common forecasting assumptions. Common process and common cycle are what they support but for technical inputs, some will need to vary.
- **NSTAR Electric Company d/b/a Eversource Energy ("Eversource")**: Echoes Nation Grid's comments. There needs to be consistency on process and how forecasting is done and how they align with state climate policy. Individual tools that are used for analysis, there may be some synergies and commonalities but too much may cause disruption, points to collaboration.
- **Massachusetts Clean Energy Center ("MassCEC")**: Consistent assumptions through 2050. Use consistent data sets.
- **Daymark Energy Advisors ("Daymark")**: Planning analysis assumptions around dependency where systems are related/abutting should be clear and coordinated. Notes that reporting, not only assumptions, should be uniform. Common reporting requirements of findings would be useful.

Should a long-term system planning committee(s) be established?

1. **If so, should there be a Distribution Company committee? and/or should there be a stakeholder committee or working group to provide consolidated input during the Analysis Process?**
2. **Who should the members of the committee(s) be? and Who should lead the committee(s)?**

Comments:

- **Eversource**: EDC committee would be of limited value. Doesn't see how they could have a long-term process without a stakeholder committee. Encourages the

Massachusetts Department of Public Utilities ("DPU") to lead that and the EDCs would help run on their respective pieces such as sharing forecasting and results and costs. Needs a stakeholder process with discrete governance. Members should be DG solar committee and policy makers, environmental justice ("EJ") communities, solar customers…etc.

- **National Grid**: Agrees with Eversource on stakeholder input and review. Sees a strong case for EDC working group for forecasting and processes. Clear touch points with stakeholder that would give opportunity for public (stakeholder) review to help provide meaningful feedback. Similar to the Massachusetts Technical Standards Review Group ("TSRG"). Does not want broad stakeholder committee oversight.
- **AGO**: Supports process for robust and wide committee of stakeholders.
- **DOER**: Supportive of stakeholder committee.
- **MassCEC**: Happy to play the role MassCEC is currently playing in the Energy Storage Interconnection Review Group ("ESIRG"). Concerned about resource availability when considering involvement.
- **NECEC**: Need some sort of committee and DPU is best to drive that with an aggressive timeframe and a balance with stakeholder involvement that includes EJ stakeholders.
- **Borrego Solar Systems, Inc. ("Borrego")**: Both committees are practical. Need to think about local outreach and local stakeholder involvement. Supports AGO recommendation for dedicated DPU position to this, or third-party facilitator. Should have access to consultant for discrete issues
- **Unitil**: EDCs present to stakeholders and in that process, the EDCs would be running it and showing their planning report and recommendations. Need to narrow definition of stakeholder committee, should not have input into/defining EDC distribution planning process.
- **Zero Point Development, Inc. ("Zero Point")**: Favors broad stakeholder engagement. Encourages DPU to have a staff member involved in the process.
- **National Grid**: EDCs showed where in the process that would engage stakeholders. Risks to calling it a committee and favors calling it a "public review process". Easier, fair and transparent to allow for public review rather than formal committee/membership meetings.

- **AGO**: Need to make sure small DG is represented. Important to include more transparency and public discourse. EDCs running everything and adjudicatory process is not transparent, need a process that makes sure everyone is involved.
- **Coalition for Community Solar Access ("CCSA")**: Strongly supports the AGO's comments. Example for stakeholder engagement is to look to Hawaii, clear plans for stakeholder and public engagement.

Discussion 2: Program Process

What should the frequency be of the Distribution Company Analysis Process?

Comments:

- **AGO**: The process is ongoing and should not stop. Gathering the groups should be ongoing and not based on frequency.
- **Heartwood Group, Inc.**: Favors a continuous process. Pointed to considerations and constraints that should be considered in the planning process.
- **Eversource**: Process should be buttoned down to include forecasting assumptions, then move to analysis stage, then share results of analysis and solicit input to develop solutions, then finalize solution set, then put forth formal results and proposal process. Need final determination of what system upgrades are to help with planning analysis. The process should be at least bi-annual with four touch points and followed up by the conclusion of the adjudicatory process before moving onto the next process.
- **National Grid**: Generally, agree with Eversource comments/timeline of annual assessment. Supports biannual approach.
- **Eversource**: EDCs process and cadence of those meetings provides feedback loop for how much time the ECCs will have to turn process around. If there is a lot of feedback from a lot of stakeholders, which may or may not be productive, this limits some stakeholders input on the analysis stage.
- **Zero Point**: Biannually, meaning once every two years.
- **National Grid**: Clarified biannually meaning once every two years, not twice a year. Pointed to urgency in highly saturated areas.

- **Eversource**: Transmission upgrades will be an impediment to increasing DG. Concerns about transmission upgrades and distribution upgrades are on different timelines.

What should the frequency be of the Distribution Company's formal filing for approval with the Department?

Comments:

- **AGO**: Emphasized that we cannot be stuck in the silo of system planning and enabling DER. This is the place to bring everything together, energy efficiency, grid mod, etc. Need to consider this is terms of frequency of filings. This needs to be developed in consideration of one another to avoid ratepayers paying more than they need to. DPU should consider having an initial filing on the shorter-term side so we can align this planning with rate cases.
- **Eversource**: Approximately once every 1.5 years.
- **DOER**: Supports the AGO position for planning to consider all larger issues.

Should the Analysis Process and formal filing be at different intervals? If so, should the Distribution Companies be required to submit compliance filings after completion of each Analysis Process?

Comments:

- **Daymark**: Process of compliance filing would be helpful if it moves forward in a helpful way
- **National Grid**: Annual Reliability Report is already an annual filing requirement that exists. So, this would be an enhancement to forecasting requirements.
- **Strategen**: EDCs should move toward an annual distribution system capacity review and planning process. Should also include an annual filing, could also consider biannual but moving towards annual will support future implementation of DG.
- **Unitil**: Annual planning process would be burdensome from a resource standpoint. DPU is contemplating how a timeline should be included in the framework.
- **AGO**: When talking about analysis process versus filing, we are all trying to get to a streamlined process.

- **Eversource**: Fully agrees to proactively build infrastructure to enable DER. Should be planning long term solutions. Distribution base plan that projects load growth, we assume that as a foundational basis of modeling what incremental needs there are on our electric power system. End goal of this should be to determine capital investment project ("CIP") fees to project DER costs. Does not consider D.P.U. 20-75 an opportunity to dissect base distribution capital.
- **National Grid**: Analysis on entire distribution system will muddle results that should be focused on a specific need in certain area.
- **Klavens Law Group**: "If you build it will they come". EDCs are digging into past practices and not focusing on things that can be done differently or recognition on innovation, how the process will be improved. EDCs should be thinking about how they're going to interact with their customers.
- **Borrego**: Two-year process puts developers in a better place. EDC capital planning cannot be done siloed from this effort, transmission and distribution infrastructure planning. Unsure about where transmission lies in this process/program.
- **DOER**: Concerned about timing, wants a long-term plan started quickly. Talking about 2026 to getting some plan rolled out so don't want too much scope in the long-term planning upfront, no desire to rewrite everything. Goal is to increase transparency. Timing should be aligned in the beginning.

Discussion 3: Straw Proposal Revisions

Should a LTSPP include both a CIP Fee and a Common System Modification ("CSM") Fee?

- **Eversource:** No need for a CSM.
- **Avid Solar**: The flip side of cost causation is that beneficiaries should pay. Lots of simplified interconnections connect through shared transformers – will be very useful as we begin to electrify heating and transportation. Cost causation is unfair; you run into the straw that broke the camel's back problem. Costs should be spread across all ratepayers because everyone benefits from increased capacity. Pro-CIP fee and CSM fee. Very concerned about the "vanishing" expedited process. Very often projects are subject to impact studies: DPU and others should get a larger share of projects through the expedited process, maybe incurring CSM fee.

- **Unitil**: Most upgrades for simplified projects are replacements of distribution transformers. Reiterating Avid Solar's comments that a CSM is appropriate for simplified projects given cost causation's fairness problems. Especially for underground upgrades, upgrade fee can be very large – a $15k-20k fee can fall on one customer for a transformer upgrade.
- **National Grid):** A CSM for smaller facilities is appropriate. Maybe there should be a kilowatt ("kW") cutoff (25kW and lower?) and basing it on size may be more appropriate than basing it on process. Common modifications in CIP areas – concerned for incremental recovery of costs, and the need to make this a more permanent part of process.
- **AGO:** Capacity increases will further stress the process/system. Charging for export is good, it can't just be a CSM fee. Need to focus on what do interconnections mean for the system as a whole and for ratepayers. Before we jump into the CSM fee, need to think about how to optimize export behavior to create a more effective pricing structure.
- **Klavens Law Group:** Pro-CSM. DG role in DERs is equally important to the benefits flowing from them. Concerned about utilities' accounting costs transparency for shared customers, DPU needs to be mindful of this, especially as DPU hasn't had as much insight into challenges that come with shared costs.

Should the Common System Modification Fee (if the program includes one) be specific to interconnecting customers interconnecting under the simplified process?

- **IREC:** Pro-CSM for larger, expedited projects.
- **Avid Solar:** CSM fee should be structured as cost recovery. 5 cents per watt or less for simplified or less, which should cover costs, before sharing with other ratepayers as other customers benefit from things like transformer upgrades. 20 kW is the max of DG that can feed into shared transformers, but given EV charging systems, need to include benefits to other customers. Hoping for a revised expedited process that's cookie cutter. Should include projects with energy storage (no impact study) – that can apply effectively and interconnect with a CSM that covers other distribution line costs. Need to expand/accelerate/standardize expedited projects up to a certain size (500 kW?)

- **Borrego:** Part of answer to this question is what the DPU views as a CIP. The CSM fee is additive to CIP process/fee.
- **MassCEC:** Encourage DPU to consult DOER regarding solar siting studies and modifications to solar policy for Commonwealth's broader DG goals, especially for small commercial and residential consumers. Don't want to work at cross purposes with solar policy.
- **Unitil:** In favor of National Grid's proposal to base CSM fee on size, not process, especially given that TSRG is considering changing process. Larger customers, say, 500 kW, are on their own transformers, they're not sharing, so CSM doesn't fit well with them anyways.
- **Strategen:** General concerns about cost causation and fee constructs. DER scaling based on magnitude of fees and charging different size facilities to achieve policy goals. How do we align fees with FERC Order 2222, especially on override conditions, how we define firm export, and whether distribution fees will be collected through distribution access tariff? Favors comprehensive evaluation to ensure alignment and long-term vision in Commonwealth is scalable.

Open comments on general revisions to straw proposal

- **NECEC:** Time sensitivity is crucial, would prefer clarity on process even if it's not perfect.
- **Avid Solar:** DPU had a max $50/kW proposed CIP fee. Why did DPU do that? Fee is "odd and unproductive," doesn't make sense given history. The perpetual group study process is clogged up. Reiterating NECEC's concerns – industry wants to move quickly. Other concerns include, given aggressive growth targets for renewable and hydro, offshore wind, etc. there is potential for solar to do more, but we're frustrated by cost and time required to interconnect, which is the main obstacle.
- **MassCEC:** Reiterating NECEC's point; DPU should consider not just timeline for approved plans but how long it'll take EDCs to execute those projects. We're hearing 4-7 years from developers. To hit 2030 targets, there are lots of constraints around getting to the first approved plan. This is an iterative process – more important to start it and improve than get everything perfect beforehand.
- **Heartwood Group, Inc.:** Echo what everyone else has said. Request that ongoing studies be made public for increased transparency.

- **Borrego:** Transmission is a critical bottleneck in Massachusetts. Coordinating/streamlining is the only hope to get out of this cycle given 2-year distribution interconnection process + 2-year transmission interconnection process. Massachusetts has one of longest processes of any state to interconnect DG.

Discussion 4: Program Eligibility Criteria

Should there be a cap on the CIP fee?

- **Zero Point:** Reiterate. $500/kW – this data is not informative. Where did majority of folks interconnect? Sometimes facilities are contractually obliged to deliver certain amount of megawatt. This $/kW rate is extremely high/unaffordable especially if you're looking at energy storage. Pro-CIP but needs to be realistic. If there's broad stakeholder involvement, then maybe we need a cap. Costs are up, it's impossible for anyone to predict, so we need be some way to control costs. Messaging expectations is the most important issue to determine if certain upgrades don't make sense given costs
- **Eversource:** CIP fee cap may be prudent in the provisional program because we know where upgrades are and DG is, and we're solving for that. In context of long-term planning where we're forecasting, having the right price signals is appropriate. We don't want expensive, non-cost-effective upgrades. Long-term is different than provisional. If the goal is to enable the most DG and have heavy stakeholder participation, no need for a cap
- **National Grid:** No need for an "artificial cap" that pushes costs to customers when it's DG customers that benefit from it. It's not optimal public policy to pay more for escalating interconnection costs when core technology costs for solar and batteries continue to decrease. We don't want arbitrary caps on CIP fees, but also don't want to build upgrades that'll strand CIP costs that'll be rolled into base rates. Share concern for customer affordability – the more we can integrate and see combined benefits, the better. End of day, we want to make sure that DG can interconnect where it can affordably. To the extent that we need to rebuild the system for customer reliability needs, we need to retain control of planning process and how that'll work. We can't offload those costs onto future DG customers that never materialize.

- **NECEC:** We need to decrease costs of interconnection. Pro-cap, as it creates certainty for the development community to know risk level around interconnection costs.
- **AGO:** Agree with NECEC and National Grid. Maybe the cap is a signal not to invest in certain upgrades and is a signal to utilities that DPU won't approve and EDCs shouldn't bother. Cap signals a lot about who's bearing risk. The cap could offer price predictability for developers. Process is predictability, that's how we should build it out – price stability and planning predictability.
- **Daymark:** The CIP fee doesn't exist in a vacuum – it's the consequence of a set of analyses. Also needs allocation work – what are costs associated with infrastructure for whom the principal beneficiaries are DERs vs others. Think of cap as policy instrument. Needs to interact well with other policies that encourage development of certain resource types.
- **Avid Solar:** Anti-cap; it has nothing to do with price signals and has no constructive value, so disagree with NECEC and AGO. Cap doesn't signify any type of threshold to anyone. Just means that any type of CIP proposal couldn't go forward. Like to see a hosting capacity map that's pricing map – color coded by DG development cost-effectiveness.
- **IREC:** Agree with NECEC that a cap can provide certainty and balance against risk of overestimating DER growth or investments that'll be necessary. Maybe start without the cap and see if it's necessary later
- **Zero Point:** A CIP fee that's known ahead of time is different than an unbounded one that's determined only after an impact study, when you're already $50k+ deep in fees plus lawyer costs.
- **National Grid:** DPU could use cap to determine whether to approve CIP filing. To Avid Solar's point on hosting capacity maps, it's unrealistic, and hard for utilities to maintain a hosting capacity map with costs to that level of detail.
- **Avid Solar:** To Zero Point's point, without a CIP fee, if a capital project is too costly, you don't know that until the money has already been invested, and you can't negotiate in front of DPU. To National Grid's point: with appropriate investment, we could do the map thing.
- **Heartwood Group, Inc.:** What geographic area would cap be imposed in? Statewide? County wide? Each would have a different impact. There is value in

having caps as price signals but definition of geographic areas is important. Impossible to have a cap on CIP fees and cap on costs to ratepayers

Should there be a cap on the cost to ratepayers?

- **Eversource:** A cap on one works, but not on both – the equation doesn't solve. A cap on CIP fees means most costs go to ratepayers. LTSPP should align with Commonwealth's clean energy goals. Should start with a forecast for DG in an area, determine constraints, then work with stakeholders to identify the most cost-effective solution. If you cap any part of this process, you have to go back to the drawing board when you're already down the road. Pro cap-as-upper-bound for determining which projects are worth pursuing. Analysis Process could inform future policy incentives, for DOER for instance. Need to fix front end, figure out what you're solving for. Then policies and incentives need to follow. Can't be the other way around.
- **AGO:** Pro-ratepayer cap. Need to focus on climate goals but we're creating a special planning process that is divorced from ratemaking treatment basis, and we still need to protect ratepayers who are at risk for all of this. Are we encouraging development in the wrong places? If it's not a cap, then there needs to be an overall cap on spending in each filing. We're creating special mechanism here and need to be careful. Should start with lowest hanging fruit and most cost-effective locations.
- **Blue Wave Solar:** Bridge between AGO and Eversource: if upgrade exceeded both caps, then we shouldn't do it.
- **Amp Energy:** Regarding the cost issue: rather than a subsidy, think about it as unsecured loan. If enough DG is built, ratepayers will get their money back. The question is: will enough DG get built for ratepayers to get the principal back? Benefits are not just renewables deployment and clean energy – we're rebuilding the Commonwealth's distribution infrastructure, which benefits ratepayers beyond carbon emissions.
- **Eversource:** Agree with Blue Wave Solar. If the objective is enabled DERs, and every upgrade enables a certain amount of DG, we should think about it in totality. What are we getting and what's it costing? Should have to show what investment per DER enablement is a percent of Commonwealth's clean energy goals. Determine if we're spending too much to enable too few DERs.

- **AGO:** Hate the phrase "unsecured loan" – it's correct when ratepayers are paying a return on this – the EDCs are making money on these deals, ratepayers are not. What are ratepayers paying for? Climate goals, yes, but also enabling DG interconnections, jobs, etc. And the EDCs' shareholders make money off this. We need to center this on ratepayers and having cost guardrails is critical.
- **MassCEC:** Is the main goal of these projects enablement of DG rather than broader policy goals? What is the right answer if the motivation of a project is load incrementality rather than DG incrementality?

Discussion 5: Minimum Filing Requirements

<u>Question</u>: If the DPU establishes a LTSPP should the DPU revise any of the minimum filing requirements directed in D.P.U. 20-75-B?

- **Eversource**: Yes, for D.P.U. 20-75-B the minimum requirements are good. For long-term planning, may want to consider some changes, including to require the EDCs to identify what policy changes would be needed to effectuate plans (to the extent that the minimum requirements add percentage of enablement of DG toward meeting clean energy goals). If the equation doesn't solve and we end up with CIP fees in excess of $750/kW, should it not inform future design incentives?
- **Keegan Werlin, LLP**: Requirements for 20-75-B are clear, no major issues with those going forward. Seeking clarification on the EJ issue moving forward. Equity issues and EJ requirements are important and well-established in legislation. As a result, it would be helpful to get clarity from the DPU on where the EDCs should go. EDCs don't want to guess on where to go (note: seeking feedback in the forthcoming CIP filings). Cost concerns are clear, but additional guidance would be helpful.
- **Daymark**: Requirements that might be helpful to add: what the planning objective is (reference to Eversource); have EDCs articulate their planning objective and what they're solving. Variations in EDC approaches might be reasonable but planning processes and planning standards should be clear. Because we're talking about long-term, baseline needs to be clear to understand amount of enabled DER. To the extent that there are other benefits accruing, these need to be clearly articulated. Recommends ensuring evaluation of non-wires alternatives ("NWAs") to ensure consideration of least-cost approach.

- **AGO**: May need to wait to determine requirements (citing 20-75-B). We are going to learn a lot from the CIPs. We should be open to making changes based on what we learn there. Should consider what NWAs bring to the table, and coordinate with GMP and EE. To address EJ communities, and to Keegan Werlin's point, we need more details. On EJ issues, we need to think about everything: siting, outreach, costs, disruptions to lives and working environments. Encourage the DPU to consider outreach plans. Taking this opportunity to work with Eversource & National Grid to put more thought into this approach
- **National Grid**: Want to see a few changes to the requirements. As covered earlier, recommend lifting the CIP cap. Regarding the timeline of proposed projects that come out of area studies, the 4-year development timeline requirement is going to be difficult to meet in light of supply chain issues. Flexibility is appreciated.
- **DOER**: Opinions on scope are clear – 2050 clean energy goals should be considered. If long-term process narrowly considers 10-year timeframe and solely DG development, we would want to understand whether modifications would need to be upgraded again to meet 2050 goals. Helpful for us to know if there are going to be issues or dead ends with meeting goals.

<u>Question</u>: What, if any, additional minimum filing requirements should the Department direct?

- No additional comments

III. SOLICITATION OF COMMENTS

The Department seeks written comments from:

1. Any interested participant regarding incorporating the Staff Notes set forth in Section II into the D.P.U. 20-75's Administrative Record.

2. The entities whose April 13, 2022 Technical Conference discussion/comments are summarized in Section II above. Specifically, whether the Department has accurately characterized the oral discussion/comments provided during the Technical Conference. If necessary, you may **briefly** supplement or clarify the Staff Notes to ensure accuracy or identify missing comments. This request is not, however, an opportunity to provide new information or restate information previously provided.

Comments shall be submitted no later than 5:00 p.m. on Friday, June 24, 2022. Joint submissions are encouraged. All written comments or other documents must be submitted to the Department in .pdf format by e-mail attachment to dpu.efiling@mass.gov and katie.zilgme@mass.gov. The text of the email must specify: (1) the docket number of the proceeding (D.P.U. 20-75); (2) the name of the person or company submitting the filing; and (3) a brief descriptive title of the document. All documents submitted in electronic format will be posted on the Department's website as soon as practicable at https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber (insert 20-75). To the extent a person or entity wishes to submit comments in accordance with this memorandum, electronic submission, as detailed above, is sufficient. To request materials in accessible formats (Braille, large print, electronic files, audio format) for people with disabilities, contact the Department's ADA coordinator at DPUADACoordinator@state.ma.us.

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