COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Inquiry by the Department of Public Utilities on its own Motion into Distributed Generation Interconnection	)))))	D.P.U. 20-75

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I. INTRODUCTION

On October 22, 2020, the Department of Public Utilities ("Department") issued an order opening an investigation into Distributed Energy Resource[1] ("DER") planning and assignment and recovery of distributed generation[2] ("DG") interconnection related upgrade costs ("Order"). Consistent with the schedule set out in the Order, as modified by the granted motion for extension, stakeholders submitted initial comments in this proceeding on December 23, 2020, and the Department of Energy Resources ("DOER") now timely submits this reply comment.

II. EXECUTIVE SUMMARY

DOER agrees with stakeholders that the Department should establish a robust DER planning process that identifies the most cost-effective pathway to integrate various levels of DG and DERs into the distribution system. Significant levels of DERs are needed to meet Global Warming Solutions Act[3] ("GWSA") limits and, consequently, integration of those facilities is a priority for DOER. Also, DOER agrees that the Department should establish a fair and equitable cost recovery and allocation process for distribution system upgrades necessary to integrate DG.

In this reply comment, DOER responds to the initial comments of several stakeholders highlighting important issues and clarifying DOER's position on matters in this investigation. In Section III, DOER highlights broad stakeholder support for the Department's DER system

[1] For the purposes of this document, DOER adopts the Department's definition of "DER" from its straw proposal. There, the Department states that, "[f]or purposes of this Straw Proposal our working definition of a distributed energy resource is a resource that: (1) is directly connected to the distribution system, or indirectly connected to the distribution system behind a customer's meter; and (2) generates energy, stores energy, or controls load. Under this definition, distributed energy resources include distributed generation (e.g., solar panels), energy storage systems, electric vehicles, and controllable loads (e.g., heating, ventilation, and air conditioning systems and electric water heaters)." D.P.U. 20-75, Att. A, p. 3, FN1 (2020).

[2] For the purposes of this document, DOER adopts the Department's definition of "DG" from its straw proposal. There, the Department states "[f]or the purposes of this Order and the attached Straw Proposal, the Department intends the term DG to refer to any type of facility that must submit an application under a Distribution Company's DG Interconnection Tariff, regardless of whether it actually generates electricity (e.g., energy storage systems). D.P.U. 20-75 Order, p. 1, FN3.

[3] M.G.L. c. 21N, § 3; St. 2008, c. 298.

planning framework and the need to plan for DER growth necessary to meet GWSA limits. In Section III, Subsection A, DOER recommends that the Department design a three-tiered stakeholder process to advance short-term progress on DER planning while creating a DER Long-Term Planning Working Group for stakeholders to advance longer-term objectives for the DER planning process. In Section III, Subsection B, DOER addresses stakeholder responses to the Department's questions issued in this proceeding, as follows:

- DOER supports flexible classification of capital investment projects ("CIPs") so that the electric distribution companies ("EDCs") can consider upgrades as well as alternatives to upgrades such as non-wires alternatives ("NWAs").[4] This inclusion is necessary to implement the most cost-effective solution to integrating DERs, however, flexibility should be balanced given the importance of fee affordability and potential ratemaking implications.

- DOER supports a DER planning process that includes electric vehicles ("EVs") and heat electrification inputs, identifies upgrades needed to integrate EVs and electric heating loads into the distribution system and considers transmission system upgrade and study costs, where possible. The Department should support standardized quantification of EV, heat electrification or other benefits associated with upgrades and should be allocating costs commensurate to benefits received by developers and ratepayers.

- DOER supports National Grid's request for additional time to collaborate with the other EDCs on providing stakeholders with information about planned projects within hosting capacity maps and requests that the Department set a reasonable timeframe for the EDCs to report back.

- Given the nature of the pre-approval for capital investments and the accompanying cost review, DOER remains unclear as to whether a cap on upgrade costs paid by developers is needed and defers to the Department on this issue.[5]

- DOER responds to EDCs' data provided in this docket by requesting projected bill impacts of estimated caps on recovery of capital upgrades.

- DOER highlights the broad support for a Common System Modification ("CSM") fee for Simplified facilities and makes several recommendations for how to

[4] In its initial comment, DOER noted that NWAs could include shifting renewable generation onto peak or high net-demand periods, curtailment of excess generation, and providing limiting export options as alternatives to capital investments for integrating DG. DOER Initial Comments, p. 11 ("DOER Initial").
[5] DOER Initial, p. 17.

structure the fee. Based on DOER's own analysis of EDCs' data, DOER recommends the Department consider establishing the fee at the lower end of proposals at $25/kW of export capacity or at a fixed rate of $100/project, without any additional charges. Fees should be used towards capital upgrades that enable integration of Simplified facilities.

- DOER continues to support a CSM for Expedited and Standard facilities, even though the EDCs opposed such a fee. DOER supports a CSM for Expedited and Standard facilities because the CIPs may not be sufficient to cover all distribution system upgrades needed to facilitate the integration of DERs, and specifically DG.

- Regarding the Attorney General's Office's ("AGO") short-term proposals, dynamic curtailment should not be ruled out. If it is not adopted now, it should be evaluated periodically. As for adding another static curtailment program, this does not seem necessary at this time given that the EDCs already include curtailment in the interconnection process.

III. COMMENT

In their comments, stakeholders offer broad support for the Department's DER system planning framework and highlight the importance of including the Commonwealth's clean energy policies in the system planning process to support the growth of DERs and meet GWSA limits.[6] Stakeholders recognize that DER planning is necessary to identify the most cost-effective pathways to support DER growth. Several stakeholders highlight the importance of the 2030 Clean Energy and Climate Plan ("CECP") and 2050 Roadmap analysis in DER system planning analysis.[7] The Executive Office of Energy and Environmental Affairs released the Interim 2030 CECP for stakeholder review and input on December 30, 2020.[8] Key points provided in the Interim 2030 CECP include:

- In addition to setting an emissions reduction limit of 45% below 1990 levels in 2030, the 2030 CECP establishes a blueprint for achieving this limit equitably and

[6] National Grid Initial Comments, p.3 ("NGRID Initial"); Eversource Initial Comments, p. 2 ("Eversource Initial"); IREC Initial Comments, p. 3 ("IREC Initial"); Pope Energy Initial Comments, p. 1 ("Pope Initial"); Solar Energy Business Association of New England Initial Comments, p. 2 ("SEBANE Initial"); and Northeast Clean Energy Council Initial Comments, pp. 2-3 ("NECEC Initial").
[7] NECEC Initial, p. 11; Pope Initial, pp. 2-3; IREC Initial, p. 3; and NGRID Initial, pp. 49-50.
[8] *See* "Massachusetts Clean Energy and Climate Plan for 2030" ("2030 CECP"), *available at* https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2030.

affordably, with major new initiatives advancing decarbonization in the Commonwealth's building, transportation, and electricity sectors.

- Massachusetts is largely on track to attain a reduction of more than 4.2 MMTCO2e in the electricity sector over the next 10 years.[9]
- To achieve emissions reduction limits in 2030 and the Net-Zero emissions limit in 2050, the Commonwealth must accelerate the growth of clean electricity, including solar photovoltaics ("PV").
- The 2030 CECP identifies that the most likely and cost-effective path toward required emission reductions will include the deployment of an additional Gigawatt of DG, including solar PV.[10]

Although the GWSA emissions reduction limits are economy-wide, pathways to Net-Zero will include significant amounts of DER growth and additional electrification, which in turn will require significant investment in the distribution system, as demonstrated by the 2030 CECP. Thus, a strong planning process with significant stakeholder input is essential to cost-effectively plan the distribution system to accommodate these developments.[11]

A. DOER Response to Comments on Use of a Stakeholder Process for DER Planning

Stakeholders generally support utilization of proper planning processes to correctly identify the most cost-effective pathways to support DER growth. The AGO notes that without a comprehensive planning process, the EDCs may make unnecessary utility investments to maintain a resilient grid.[12] Further, the EDCs suggest methods for integrating DER into their planning processes.[13]

[9] 2030 CECP, p. 37.
[10] *Id*.
[11] DOER Initial, pp. 15-16. Although at least one stakeholder requested for DOER to establish targets for solar to assist in the DER planning process (*see* NGRID Initial, pp. 48-50), DOER intends to participate in the stakeholder input process to help ensure that the process is consistent with the 2030 CECP and Roadmap.
[12] Office of the Attorney General Initial Comments, p. 3 ("AGO Initial").
[13] Unitil Initial Comments, pp. 2-9 ("Unitil Initial"); NGRID Initial, pp. 10-15; and Eversource Initial, pp. 3-17.

Incorporating assumptions regarding DER growth into the EDCs' established distribution system planning process is both important and complex. Although it is imperative that the EDCs make progress in the short-term to incorporate changes into their respective planning processes accounting for DER growth, there are important long-term benefits to establishing a holistic planning process built through collaboration and stakeholder input. For instance, the AGO outlines a detailed plan for a Pre-Implementation Working Group with several important objectives.[14] The Northeast Clean Energy Council ("NECEC") states that "proposed distribution planning efforts should not wait for the comprehensive joint transmission and distribution planning framework to be developed and implemented."[15] After reviewing initial comments, DOER recommends that the DER planning and system upgrade identification process (i.e., CIP upgrades) proceed in three stages, as outlined below:

1. Stage One: The Department Should Establish a DER Planning and Reporting Requirement for the EDCs

DOER agrees with the EDCs that they should update their existing distribution planning process to include a forecast of DER growth that allows for the identification of distribution system upgrades and provides recommendations for stakeholder input.[16] DOER responds to the following stakeholder comments on stakeholder process and input into DER planning and recommends the

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[14] AGO Initial, pp. 4-5 (noting three objectives: the Pre-Implementation Working group will draft a public document detailing a statewide vision for the Commonwealth with respect to distribution system planning and cost allocation; EDCs will develop a baseline of knowledge of individual distribution system and existing DER capabilities and; each EDC will conduct a gap analysis/closure action plan which will identify the gaps between the working group's vision statement and the EDC's baseline capabilities).
[15] NECEC Initial, p. 11.
[16] Eversource Initial, p. 3; Unitil Initial, pp. 2-3; and NGRID Initial, pp. 8-9. Eversource noted that the Company's existing Distribution System Planning Guide includes load and DER forecasting and could be used efficiently to coordinate capital projects with DER upgrades. Eversource Initial, p. 9. Unitil plans on utilizing their existing planning process as well, extending to a 10-year planning assessment. Unitil Initial, p. 8.

Department require the EDCs to develop and file a DER Planning Report that reflects the following characteristics:[17]

- **Set Consistent Load Forecast Assumptions:** It is essential that DER planning utilizes a consistent set of DER and load-forecasting assumptions developed in coordination with stakeholders. Eversource supports the establishment of a stakeholder process to develop regional DG forecasting assumptions.[18] DOER recommends that, although forecasting assumptions will likely vary by location, the assumptions should represent a cohesive vision for DER growth in the Commonwealth. The AGO similarly notes the importance of a comprehensive process in its plan for establishing a Pre-Implementation Working Group.[19] Consistency in load-forecasting assumptions will help facilitate meaningful stakeholder input on investments proposed as a result of the DER planning process.

- **Create Consistency with the 2030 CECP and Future CECP Updates:** The forecasting assumptions used by the EDCs should be consistent with the likely pathways described in the CECP. Eversource proposes a stakeholder process that will provide an opportunity to integrate public policy information on DERs and electrification into forecasting assumptions.[20] These assumptions will represent a likely pathway to increase DER deployment, but the 10-year forecast should be continuously updated with better information as it becomes available to reflect DER market, development, and policy changes.[21]

- **EDCs Submit DER Plan Filings Prior to Pre-Approval Submissions:** The AGO asserts that the ability and quality of stakeholder comment on the investments will depend on the information and data provided by the EDCs.[22] DOER agrees and recommends that the EDCs file a report with the Department on the results of the DER Planning Process at regular and consistent intervals in a format that allows for meaningful stakeholder review and input ("DER Planning Results Report").

Information provided by the EDCs in the DER Planning Results Report should include a full description of common assumptions and planning results, such as multiple forecasting

[17] This report is intended to be focused on DER planning as envisioned in the Department's D.P.U. 20-75 straw proposal, and not necessarily the broader distribution system planning process.
[18] Eversource Initial, p. 3.
[19] AGO Initial, p. 3.
[20] Eversource Initial, pp. 4 and 7.
[21] The 2030 CECP does not contain technology-specific targets and likely pathways to emissions reductions may shift with technology development.
[22] AGO Initial, p. 10.

scenarios to recognize that assumptions may include a range of possible pathways. Eversource highlights that modeling of multiple scenarios will provide the greatest amount of information for identifying properly sized upgrades.[23] The DER Planning Results Report should also identify both near-term and long-term constraints over the 10-year planning period, identifying possible investments and upgrades as solutions.[24] Although stakeholder input on specific DER technologies or mitigation strategies is reasonable and necessary in advance of any pre-approval process for EDC investments, DOER agrees with Eversource that ultimately all decisions that impact the safe and reliable operation of the distribution system remain with the utility.[25] Thus, stakeholder input provided directly to the EDCs in advance of pre-approval proceedings would be advisory in nature with the EDCs holding the ultimate responsibility for determining which investments are needed to integrate DG and, more broadly, DERs. Under the Department's proposal, the EDCs must demonstrate that proposed investments are reasonable and therefore should be pre-approved. Providing stakeholders an opportunity to preview planning results will likely increase the administrative efficiency of the pre-approval proceedings as stakeholders can discuss possible mitigation strategies with EDCs before those proceedings.

2. Stage 2: Review of CIP Investments

After the EDCs have updated and reported on the DER Planning Process, the EDCs should identify CIP-eligible investments in a filing to the Department that describes the investment and expected cost, the cost allocation between DG customers and ratepayers, and how the investment

[23] Eversource Initial, p. 8 (discussing a probabilistic scenario-based DER adoption rate and load forecast methodology).
[24] *See* DOER's response to Question 1.e.ii on hosting capacity maps and presentation of information on existing and planned hosting capacity.
[25] Eversource Initial, p. 4.

was identified in the System Planning Process. The CIP recovery filing[26] could be due at regular intervals, as supported by Unitil, or as the investment is identified, depending on the frequency of necessary CIP projects.[27] Eversource describes a CIP identification process in its initial comments, recognizing that filings may include a list of projects and a range of costs that the Department would review and approve.[28] This filing should also provide all necessary information to justify the cost allocation of upgrades.

3. Stage 3: DER Long-Term Planning Working Group.

NECEC supports an EDC-led working group at quarterly intervals while the AGO recommends a working group led by non-EDC subject-matter experts and a two-sequence planning process.[29] DOER recommends a working group that focuses specifically on long-term objectives consistent with many of the objectives identified by the AGO for their Pre-Implementation Working group. However, the working group should not delay the DER Planning Report, as outlined below.

After the implementation of a DER Planning Process and CIP Identification, DOER recommends a third, collaborative stage that identifies long-term objectives to improve the DER Planning Process and allows for an open and transparent discussion on how best to integrate clean energy goals into the distribution system. This "DER Long-Term Planning Working Group," should meet at regular intervals, at least every two years, and should include the EDCs, state policy makers, and additional stakeholders focused on planning process impacts and successes and aligning investments with meeting GWSA goals. DOER supports a working group structure that

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[26] DOER discusses the technologies that should be CIP eligible in response to the Department's Question 1.a. DOER also discusses benefits and the inclusion of cost allocation in these filings in its response to Question 1.b and 1.c.
[27] Unitil Initial, p. 2.
[28] Eversource Initial, p. 19.
[29] NECEC Initial, p. 15; and AGO Initial, p. 3.

allows for collaboration and input from a wide range of stakeholders where the EDCs may actively participate and provide data in a transparent matter. This working group may also benefit from sub-groups or breakout groups that meet more often than bi-annually.

DOER recommends that the DER Long-Term Planning Working Group be developed after the DER Planning Process and CIP Identification stages to prevent delays to improving the current consideration of DER and clean energy goals. As National Grid notes, transitioning to a more integrated planning process may take several years to implement.[30] This transition would be supported by the efforts of the DER Long-Term Planning Working Group through review and discussion of a broad range of tasks that could include:

- Achieving DER Policy Goals
- Coordination with Grid Modernization and Other System Investments
- Design of Performance Incentive Mechanisms
- Planning Process Design and Implementation
- Impact of Other Policy Goals
- Export-Based Cost Systems
- Inclusion of and Coordination with Transmission Investments

Several stakeholders provided comments on these topics, and DOER provides the following responses:

- **Achieving DER Policy Goals:** The DER Planning Process and CIP Project Cost Recovery incentivize the EDCs to build, but do not incentivize DG developers to utilize the newly-created export capability on certain parts of the distribution system. Although forecasting assumptions and consideration of policy goals may help identify the type and size of upgrades needed for integration of future DER, policymakers and other stakeholders can support the use of these upgrades through complementary programs such as targeted deployment of electrification and energy storage or localized DG incentives. The AGO recommends the EDCs create DER Implementation Roadmaps that to use in their planning processes to provide transparency and establish a common understanding for DER growth assumptions and technological capabilities.[31] DOER supports having a consistent and comprehensive vision on the pace and magnitude of DER deployment as part of the EDCs' business and supports the AGO's recommendation for the creation of a state-wide vision document. However, DOER recommends it be developed

[30] NGRID Initial, p. 9.
[31] AGO Initial, p. 4.

through the DER Long-Term Planning Working Group. That vision document would be reviewed on a regular basis by stakeholders to account for DER technology and policy development over the planning horizon. This document can then be utilized in the EDCs' DER Planning Process Report.

- **Coordination with Grid Modernization and Other System Investments:** Multiple stakeholders recognize that CIP investments may have overlapping benefits with modernizing the electric system, an effort that is currently ongoing through the EDCs' Grid Modernization Plans ("GMPs").[32] As stated in DOER's initial comments, identifying the most expeditious and cost-effective solution for DER integration requires an understanding of how the costs and benefits of various investments are evaluated in different proceedings, and how cost recovery occurs. In addition, close coordination will help ensure that the EDCs make CIP and GMP investments in a complimentary manner.[33]

- **Design of Performance Incentive Mechanisms:** The DER Long-Term Planning Working Group would review the data provided by the EDCs and other stakeholders to design, as appropriate, a Performance Incentive Mechanism ("PIM") and an associated baseline, as discussed in DOER's initial comments.[34] The AGO describes one possible PIM design for CIP utilization that would ensure excess capacity enabled by the CIP is utilized efficiently.[35] Additionally, a PIM could measure cost containment to ensure the EDCs continue to identify those CIP investments with the greatest benefit to ratepayers at the lowest cost.

- **Planning Process Improvements and Implementation:** While CIP investments and cost allocation will directly affect the implementation of Commonwealth's policies around the deployment of DERs, both will also have significant implications on the pace and magnitude of electrification. The DER Long-Term Planning Working Group would be able to review the DER Planning Reports, CIP Investments, and associated data to design metrics that track the impact to ratepayer costs and benefits. This information may then be used to recommend refinements to the DER Planning Process and the CIP cost allocation methodology. Additionally, this information may be used by policymakers to shape clean energy programs.

- **Export-Based Cost Systems:** As supported by DOER and the AGO in initial comments, CIP and CSM fees should be based on export capacity, not on nameplate capacity, because export capacity is a more appropriate measure of the impact to system costs.[36] If the Department does not move forward with implementing a CSM Fee, the DER Long-Term Planning Working Group should focus on

[32] *See* D.P.U. 15-120, 15-121, and 15-122.
[33] DOER Initial, pp. 13-14.
[34] *Id*.
[35] AGO Initial, p. 11.
[36] DOER Initial, pp. 34-35; and AGO Initial, p. 10.

designing a more granular, temporal, cost-based pricing model as described by the AGO.[37]

- **Inclusion of and Coordination with Transmission Investments:** While there is broad support for the consideration of transmission costs in the DER Planning Process, stakeholders also recognize the complexities of integrating two planning processes that are implemented by separate parties, namely the EDCs and ISO-NE.[38] The DER Long-Term Planning Working Group should focus on ways to coordinate these two processes with the inclusion of ISO-NE as a stakeholder.

B. DOER Response to the Department's Questions[39]

1. Refer to Section II, Distributed Energy Resource Planning Requirements. Please discuss the effectiveness of this proposal, specifically:

a) The Department has identified the following list as solutions that address potential system needs. If you disagree with any solution included on this list, please explain why. Please identify and explain any additional solutions.

i) Technologies for Voltage Control on the Distribution System

ii) Distribution Bulk Transformer Addition or Replacement

iii) New Bulk Station

Consistent with DOER's initial comment, stakeholders support and seek to expand the list of CIP-eligible solutions identified by the Department.[40] Eversource and National Grid recommend that the Department add several solutions to its list of CIP-eligible solutions.[41] Unitil recommends that the Department establish an exemplary list of CIP-eligible solutions categorized by the type of constraint and asserts that the EDCs require flexibility in implementing cost-effective solutions.[42] NECEC recommends that the CIP-eligible solutions list remain flexible to include a broad range of solutions to cost-effectively integrate DG and DERs.[43] For the reasons

[37] *Id.*
[38] Eversource Initial, p. 6; NGRID Initial, p. 14; and NECEC Initial, p. 4.
[39] For ease of review, DOER has included the Department's questions and DOER's responses below.
[40] *See* DOER Initial, p. 22; Eversource Initial, pp. 5-6; Unitil Initial, pp. 3-5; and NECEC Initial, pp. 6-8.
[41] Eversource recommended expansion of the list of solutions to include distribution feeder upgrades or additions, radial transmission line addition or replacements, substation switchgear additions or replacements, and relay protection modifications or upgrades required to accommodate DER interconnection. Eversource Initial, pp. 5-6. National Grid seeks to add distribution feeder additions, upgrades, or replacements; technologies for controlling DG and DER; and active monitoring of the energy power system and DG status. NGRID Initial, pp. 10-12.
[42] Unitil Initial, p. 3.
[43] NECEC Initial, pp. 7-8.

provided below, DOER recommends the Department ensure CIP eligibility remains flexible and that eligibility is determined by evaluating first the type of constraint inhibiting the integration of DG and DER.

DOER agrees that the Department should provide flexibility in CIP-eligibility for identifying the most cost-effective solutions to integrate DERs and DG. The Department should not establish a list of CIP-eligible solutions that presupposes which solutions are most cost effective. The Department should leave CIP eligibility flexible to incentivize the EDCs' consideration of a range of solutions to address DG and DER constraints to include not only capital upgrades but also other solutions such as NWAs. A flexible approach to CIP eligibility may also encourage EDCs to consider new business models that will resolve capacity constraints and enhance cost-effectiveness.[44]

Further, DOER supports Unitil's proposal to categorize CIP-eligible solutions by type of constraint because it facilitates a comparison of a broad range of solutions for integrating DG and DERs.[45] The Department's straw proposal appears to assume that new bulk stations are the solution to relieving capacity constraints because a new bulk station is the only CIP-eligible solution to address capacity constraints on the Department's list of projects. In contrast, Unitil's table identifies 11 typical project solutions to capacity constraints that are CIP-eligible.[46] Under Unitil's framework, the Department may select whichever solution is cost effective, whether that

[44] Such models could include an EDC's issuance of a competitive solicitation of NWAs in a manner consistent with M.G.L. c. 164, § 146(b-c). M.G.L. c. 164, § 146(b) states that "[e]lectric distribution companies may hold a competitive solicitation for electric distribution system resiliency non-wires alternatives from third party developers."
[45] DOER Initial, p. 22, FN53.
[46] Unitil Initial, p. 4. Among this list of 11 CIP-eligible projects is transmission substation addition or upgrades, transmission line addition or reconductoring, substation transformer addition or upgrade, substation circuit position upgrade, substation circuit position upgrade, new circuit position, reconductoring or cable replacement, voltage conversation, energy storage, circuit reconfiguration, switchgear addition or replacement or managed EV charging and discharging. *Id*.

is a new bulk station or another project, such as an NWA. Finally, Unitil's proposed method of categorizing types of constraints could also be used to classify upgrades based on whether they would best fit within a CIP or a CSM.

Although DOER supports flexibility in CIP investments necessary to integrate DERs and DG, DOER is concerned that overly broad CIP eligibility could result in a CIP fee that is too costly or duplicative investments recovered elsewhere. It is DOER's understanding that there may be circumstances where an EDC seeks to expand a CIP project to include safety and reliability enhancements that are not necessarily needed to integrate DG and DERS safely and reliably. Before allowing the EDCs to include such reliability or safety investments as part of a CIP, the Department should carefully consider the implications. As pointed out by the Interstate Renewable Energy Council ("IREC"), the addition of other investments to address reliability could render the CIP fee too costly, resulting either in capacity that is not subscribed by DG or in DG paying for investments that broadly benefit ratepayers.[47] This is particularly true if the costs are not allocated fairly and equitably. Further, evaluation of the potential ratemaking implications and coordination between Department proceedings is necessary to ensure cost recovery is transparent, just, and reasonable.

b) Should transmission studies and costs be included in proactive system planning as it relates to interconnection? Explain your reasoning.

Several stakeholders, including DOER, support incorporating transmission studies and costs in proactive system planning.[48] NECEC asserts that the EDCs should expeditiously

[47] IREC Initial, p. 4.

[48] DOER Initial, p. 23; Eversource Initial, p. 6; and Unitil Initial, p. 5. Eversource and Unitil point to the related nature of the distribution and transmission systems. Eversource Initial, p. 6; and Unitil Initial, p. 5. Among other things, Unitil points to the potential for transmission solutions to provide the most cost-effective solution to integration of DERs. Unitil Initial, p. 5. Eversource asserts the need to potentially upgrade transmission to accommodate higher DER injections from the bulk stations where there is higher DER penetration. Eversource Initial, p. 6. National Grid

incorporate DER assumptions into their distribution planning and those assumptions would include "known and anticipated local and bulk transmission planning activities."[49] NECEC requests that the EDCs coordinate their long term planning processes.[50] The Department should adopt NECEC's recommendation on identifying opportunities for coordination when conducting long-term planning for the system. Even in the short term, it may be challenging for EDCs to align transmission and distribution study timelines and producing reliable estimates for transmission study and upgrade costs. However, reliable estimates of transmission studies and upgrade costs are essential to development of a sound analysis of the cost-effectiveness of transmission and distribution planning solutions. Given the complexity of this topic, DOER recommends that the Department consider advancing the discussion in a technical conference or asking the DER Long-Term Planning Working Group to take on this challenge.

c) Should the distribution system assessment identify projects that provide broader benefits beyond enabling incremental DG capacity? If so, explain:
  i) what benefits should be considered
  ii) how these benefits should be quantified
  iii) the appropriate method for cost assignment and recovery.

DOER and other stakeholders support a system assessment that identifies upgrades beyond those that enable incremental DG capacity.[51] Eversource recommends an integrated planning approach to identify upgrades that provide broader benefits while accommodating load growth and high penetration of DERs.[52] Similarly, National Grid and Unitil endorse broader benefits to

also recognizes the relationship between distribution and transmission planning, asserting that the effectiveness of a distribution-level cost allocation plan will be significantly constrained if transmission studies are not included. NGRID Initial, p. 13.

[49] NECEC Initial, pp. 9-10.

[50] *Id*.

[51] NGRID Initial, pp. 13-14; Unitil Initial, p. 6 (endorsing consideration of traditional system safety and reliability benefits as well as modernization benefits such as electrification); DOER Initial, pp. 14-16; and Eversource Initial, pp. 7-9 (endorsing consideration of reliability, resiliency and operational benefits, and grid modernization benefits).

[52] Eversource Initial, p. 7.

include traditional and non-traditional benefits such as enablement of DG, EVs, and heat electrification.[53] Both companies recommend that system planning include planning inputs for anticipated load changes.[54] NECEC states that the upgrade benefits should "be informed by the Commonwealth's overall clean energy and climate goals" and assess a broad range of performance indicators.[55]

DOER agrees with National Grid's proposal to include EV and heat electrification inputs in their planning processes to facilitate the identification of projects that accommodate corresponding load growth in addition to DG.[56] The Commonwealth will need to electrify transportation and heating loads to meet its GWSA limits; thus, the system assessment should identify projects that provide these broader benefits.[57] As the state electrifies, the EDCs' system assessments must include planning for the increased electricity loads. DOER supports a broader view of benefits as noted in its initial comment, but the ratemaking implications and impacts of CIP fee levels must be carefully considered before traditional projects, such as end of life replacements of existing infrastructure, are made CIP-eligible.[58]

DOER agrees with Unitil that the Department should standardize the quantification of benefits.[59] The Department should consider whether to achieve this through a collaborative process. The Department could render a final decision on methods in an order. If the Department pursues this route, DOER recommends that the collaborative process focus on quantifying the

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[53] NGRID Initial, pp. 13-14; and Unitil Initial, p. 6.
[54] See e.g., Eversource Initial, pp. 9-10.
[55] NECEC Initial, p. 12 (seeking to assess performance improvements, quality of incremental DG that can be cost-effectively interconnected, beneficial electrification, system flexibility, resilience, and ability to meet environmental challenges).
[56] DOER Initial, p. 17 (stating the forecasting assumptions on the growth of DERs, as defined by the Department in its straw proposal, that should be included in forecasting).
[57] NECEC Initial, pp. 11-13; and DOER Initial, pp. 23-24.
[58] *See* DOER's response to Question 1 above.
[59] Unitil Initial, p. 6.

benefits of electrification and the benefits of supplying the new electric load with clean energy. As noted in its initial comment, DOER supports leveraging the substantial efforts of the Grid Modernization Laboratory Consortium[60] ("GMLC") and GridWorks to establish metric quantification of grid modernization investments and spending a portion of this investigation into developing quantification methods.[61]

When it comes to cost allocation and recovery, as National Grid explains, alignment of net benefits and cost allocation would be challenging.[62] NECEC supports a bright line rule that allocates at least 70% of upgrade costs to ratepayers.[63] Although DOER recognizes that there may be some investments that provide broad benefits to ratepayers and therefore the associated costs should be distributed across all ratepayers, such an analysis may need to be evaluated on a project-by-project or group of projects basis. DOER supports the allocation of costs that is commensurate with the benefits received. Furthermore, the Department should ensure that cost allocation results in fees that incentivize DG to locate where it is most cost-effective to integrate and maximize the benefits of clean energy generation for ratepayers. DG should be located in areas where there is greater load, especially areas with increased electrification load, if it minimizes the cost of upgrades. Ensuring the Commonwealth proceeds in the most cost-effective manner is essential, as the costs of electric distribution service will have an impact on the pace and overall success of electrification efforts.

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[60] The GMLC is a strategic partnership between the U.S. Dept. of Energy and the national laboratories.
[61] DOER Initial, p. 23, FN59 (referring to https://gmlc.doe.gov/projects and noting that some projects focused specifically on developing appropriate metrics and quantification techniques, including "Grid Modernization: Metrics Analysis," which includes Reliability, Resilience, Flexibility, Sustainability, Affordability, Security metrics, methods to baseline, and quantification.) https://gmlc.doe.gov/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf. The GMLC provides periodic updates on these projects, and updates on the Metrics can be
[62] *See* NGRID Initial, p. 14 (stating "an overall analysis resulting in comprehensive benefits provides for the most cost-effective electric system, but with challenges; specifically cost assignment would be difficult.").
[63] NECEC Initial, p. 17.

Although DOER agrees that the quantification of benefits should be standardized in advance of CIP-approval requests, the actual allocation of costs for any specific CIP can and should be addressed at the time the EDCs submit their CIP pre-approval requests.

d) Should there be a cap on the dollar-per-kW billed to each Facility that benefits from the Capital Investment Project? If so, please explain how the cap should be determined.

The EDCs oppose a cap on the dollar-per-kW bill to each facility that benefits from the CIP.[64] However, NECEC seeks to establish a cap.[65] At this time, it is unclear to DOER whether a cap is needed. DOER prefers to defer the decision to when the Department is evaluating the pre-approval requests for capital investments and the associated cost reviews.[66]

e) Requests to the Distribution Companies

i. Please propose an optimal format for the 10-year distribution assessment. Including all substantive information points that should be contained in the assessment. Please include a proposal on the frequency with which such assessments should be conducted.

Please refer to the above reply comment Section III.A.1.

ii. Please indicate the length of time required to update hosting capacity maps to reflect additional capacity built into the system after planned projects have been approved by the Department.

National Grid notes that its hosting capacity maps provide a limited view of future hosting capacity and recognizes the difficulties associated with anticipating the hosting capabilities associated with future planned projects.[67] It requests more time to collaborate with the other EDCs on "proposing a process for providing that information, including a reasonable timeline for making such updates and whether such updates should be made to the EDCs' existing capacity maps or

[64] NGRID Initial, p. 33; Unitil Initial, p.11; and Eversource Initial, p. 25
[65] NECEC Initial, p. 17.
[66] DOER Initial, p. 17.
[67] NGRID Initial, pp. 22-24.

whether separate planned hosting capacity maps would be more feasible."[68] Separately, Unitil states that the hosting capacity maps should not reflect planned capacity.[69]

DOER supports National Grid's request to allow the EDCs additional time to collaborate on this topic and to report back to the Department on how to achieve a map to demonstrate the hosting capabilities associated with planned distribution projects. DOER suggests that the manner and type of information that the EDCs provide to DG developers gives them advance notice of new CIP hosting capabilities so developers can plan to locate DG in areas with newly upgraded distribution system. This approach should help promote uptake of newly upgraded distribution system, reducing the risk that ratepayers will pay for any CIP capacity not subscribed by DG developers within the Department's proposed ten-year reconciliation period. For the reasons above, DOER requests that the Department set a reasonable timeframe for the EDCs to report back on the most suitable approaches for providing DG developers the information about hosting capabilities associated with current and future distribution systems.

iii. For illustrative purposes, please provide an estimated annual cap on the Reconciling Fee for the last five calendar years based on the description above.

Although the EDCs provided information regarding the total costs of an annual cap,[70] it would be helpful to have projected bill impacts of any rate recovery up to the cap. It is essential to ensure that the cost of electric distribution service remains affordable for ratepayers and that

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[68] NGRID Initial, p. 24, *citing to* D.P.U. 19-55-D Order, p. 6 (Sept. 6, 2020).
[69] Unitil Initial, p. 9.
[70] See Eversource Initial, "Attachment Eversource-1; Unitil Initial, Attachment A 12.4.20; National Grid Illustrative Revenue Cap for Reconciling Charge filed in DPU 20-75.

they are not unduly burdened by system upgrade costs. Affordability is crucial to ensure that electric distribution rates do not become a barrier to electrification or spur significant interest from ratepayers to defect from the distribution system, leaving more costs to be recovered from less customers. Thus, DOER requests that the Department require the EDCs to provide estimated bill impacts associated with reconciling fees and the associated cap.

2. Refer to Section III, Common System Modification Fees. Please discuss the effectiveness of this proposal, specifically:

a) Simplified Facilities

i) Is a Common System Modification Fee appropriate for Facilities using the simplified interconnection process? If so, provide a proposed method for establishing such a fee.

Eversource, Unitil, National Grid, NECEC, and the AGO provide support for establishing a CSM for facilities using the Simplified process.[71] Stakeholders recognize value in using a CSM for Simplified facilities that establishes a predictable fee for these facilities.[72] DOER agrees with these stakeholders generally and with National Grid's statement that "[s]implified projects typically are residential projects and unlike Expedited and Standard projects, cannot reduce the costs of their solar project by finding a less expensive location."[73] Below, DOER addresses stakeholder assertions regarding: (1) assessment of costs to Simplified customers in addition to the

[71] *See* Eversource Initial, pp. 23-24; NGRID Initial, p. 26; NECEC Initial, p. 19; Unitil Initial, p. 9; and AGO Initial, p. 10 (stating that "[t]he Department's $/kWh pricing proposal can address the immediate interconnection queue…").
[72] NGRID Initial, p. 26 (stating a CSM fee "is appropriate for Facilities using the simplified interconnection process … to offset the costs of System Modifications that simplified projects increasingly trigger [and] provide greater predictability to interconnection costs and timing..."); Eversource Initial, pp. 23-24 (stating "it may be appropriate for the Department to approve a unique fee structure for other types of modification projects using the simplified process that allocates a consistent amount of such facilities in order to balance cost causation goals with administrative considerations for smaller distribution facilities"); and NECEC Initial, p. 19 (stating "there is value in having cost certainty and a mechanism for allocating the cost of upgrading shared service infrastructure among simplified facilities").
[73] NGRID Initial, p. 26; matches closely to DOER's recognition of Challenges with the Current Cost Causation Principles in its proposal from D.P.U. 19-55, which was incorporated into the present docket. *See* D.P.U. 20-75, Vote and Order, Att. B-2, pp. 3-4.

CSM fee, (2) calculation of the fee and fee level, and (3) the timing of CSM fee assessment. In sum, DOER recommends establishing a Simplified CSM fee at around $25/kW of export capacity, or in the alternative, fixing the Simplified CSM fee at or below $100/project without any additional charges.

First, stakeholders offered varying fee levels and structures. NECEC recommends a Simplified CSM fee fixed at $20/kW and capped at $500 per project at the time of interconnection.[74] National Grid estimates that a one-time Simplified CSM fee assessed at the time of interconnection would fall in the range of $25-$50/kW and suggests that the facility would also be subject to site-specific costs up to a fixed amount of $5,000 to reflect circuit saturation.[75] Further, NGRID recommends that the fee should be adjusted annually.[76] Unitil proposes that "additional costs would also be assessed to individual Interconnecting Customer…" beyond the fee amount.[77]

DOER notes that NECEC's and NGRID's estimated fees are somewhat aligned. However, DOER disagrees with any structure that adds site-specific or location specific costs to a Simplified facility which is subject to a CSM fee. Site-specific costs would undermine the intent of the fee to provide cost certainty for developing small projects and open access to residential customer DER development. Further, residential customers have no control over the grid conditions at their home, so there is no reason to use site-specific fees to send a price signal.

Second, while DOER proposed a more complex fee to better reflect cost causation, DOER is open to a simpler fee structure for Simplified facilities. In its initial comment, DOER

[74] NECEC Initial, p. 19.
[75] NGRID Initial, p. 27, FN17.
[76] NGRID Initial, p. 27.
[77] Unitil Initial, p. 10.

recommended a strong weighting of the fee toward export capacity.[78] The AGO's initial comment agrees that "for the time being, a $/kW export fee may be the best available mechanism…".[79] As such, DOER is amenable to a Simplified CSM, established as a $/kW export capacity, where a customer is not subject to any additional costs for the interconnection. As noted above, and based on the analysis below, DOER recommends the Department consider establishing the fee based on export capacity that is on the lower end of the range of proposals, at ~$25/kW of export capacity, or in the alternative establish a fixed fee at approximately $100 per project. IREC provided analysis of upgrade costs for simplified projects and found the average upgrade cost in 2020 to be $83 per project.[80] DOER ran a similar analysis of Attachment 1 of National Grid's initial comment, specifically the sheet titled "Data - <= 25kW."[81]

Initial findings of interest include:

- Average $/kW of All projects = $5.87/kW[82]
- Average $/kW of Connected projects = $3.07/kW[83]
- Average Total System Modification Cost of All projects when zero-cost cells are ignored as blanks = $3,863 per project (matches NGrid tab "<=25kW (Simplified)" cell F16)[84]
- **Average Total System Modification Cost of All projects when zero-cost cells are included in the average as 0's = $45 per project**[85]

These findings are significant. Analysis of the data by both IREC and DOER suggests that if all Simplified project applications had paid a CSM of substantially less than $100 per facility,[86] then

[78] DOER Initial, p. 29
[79] AGO Initial, p.10.
[80] IREC Initial, p.13.
[81] NGRID Initial, Att. 1. DOER started by unhiding all rows in tab "Data - <= 25kW."
[82] DOER added a column L with an equation to calculate $/kW per project, providing $0 where cells were blank: "=IF([@[Nameplate AC Rating (kW)]]>0,[@[Total System Modification Cost (MECo + NEP)]]/[@[Nameplate AC Rating (kW)]],0)." DOER then took the average of column L.
[83] DOER took the average of column L, where column D was "Connected" with the equation: "=AVERAGEIF(D:D,"*Connected*",L:L)."
[84] DOER took the average of column M as provided.
[85] DOER added a column M to the data, which adds 0 to Column K. The result is Column M equals column K; however, blanks are now entered as zeros. DOER then took the average of the new Column M.
[86] IREC found $83/project looking at just 2020 data; DOER found $45 per project including all years (without attempting dataset cleanup for DIV/0 errors, etc.).

all Simplified project system upgrades would have been fully recovered and no Simplified projects would have withdrawn based on site-specific upgrade costs. DOER's findings are an order-of-magnitude lower than the fee levels proposed in initial comments ($3.07 - $5.87 / kW for upgrade costs as compared to NECEC & National Grid proposals for a CSM fee which ranges from $20-$50/kW).[87]

DOER recognizes a couple of key factors that should be considered in establishing a CSM fee. First, the dataset includes a substantial number of withdrawn applications with $0 fee. Second, whether the fee is due at the time of application or at the time of interconnection would determine whether the withdrawn projects should be included in analysis to establish the Simplified CSM Fee. Third, this analysis is based on facility nameplate capacity and not on export capacity. Given DOER's analysis and these factors, DOER thus supports a $25/kW export capacity or fixed $100 per facility Simplified CSM fee, as the data suggests this level of fee should recover the majority, if not all upgrade costs associated with Simplified facility interconnections.

Third, National Grid proposes the fee be payable at the time of application, whereas Unitil proposes the fee be assessed at the time of approval to interconnect. If the fee is fixed and low (such as a flat $100 fixed Simplified CSM fee per project), then DOER supports the fee being due at the time of application. If the fee is variable (such as $/kW export capacity), then DOER supports the fee be established and provided documentation at the time of application and the fee is due to be paid at the time of authorization to interconnect. This provides the applicant with the opportunity to evaluate whether the project will face other hurdles (such as permitting, structural

[87] NECEC Initial, p. 19; and NGRID Initial, p. 27, FN17.

assessment, etc.) that would prevent the project from moving forward. It will also help ensure that the applicant is aware of all development costs before it decides to proceed with its interconnection.

ii) What types of upgrades should be funded by a Common System Modification fee for Facilities using the simplified interconnection process?

The EDCs' and DOER's respective initial comments align regarding the use of funds collected from a CSM fee on Simplified projects. General agreement exists on the appropriateness of using funds to address system modifications required to enable continued integration of simplified facilities.[88] Modifications which primarily support interconnection of Simplified projects include service transformers, secondary (crib) reconfiguration, and service upgrades.[89] DOER agrees with this approach and recommends modifications and clarifications to this list and the CSM proposal provided below.

First, DOER recommends use of the Simplified CSM fee for substation upgrades in certain circumstances. For example, the aggregation of small projects could result in the need for protective devices at a substation and there is no forecast for sufficient future large projects to pay for the upgrades through a CIP. As a result, this upgrade is necessary to enable continued simplified project interconnections.[90]

Second, National Grid states that the CSM fee should not be used to recover costs associated with a customer upgrading from single-phase to three-phase service. DOER agrees with this recommendation since an upgrade from single-phase to three-phase service represents a

[88] Eversource Initial, p.24; NGRID Initial, p.28; and Unitil Initial, pp.10-11
[89] *See* Eversource Initial, p. 24; NGRID Initial, p. 29; and Unitil Initial, p. 28.
[90] This would provide EDCs the flexibility to resolve conditions that can otherwise stall simplified projects, such as have been faced in Lunenburg and Fitchburg in the past.

substantial improvement with real value to the facility owner that is above-and-beyond DG interconnection. Therefore, such costs should be recovered according to current utility practices.

Third, National Grid proposes to change the Simplified CSM Fee to a "Small DG CIP Fee."[91] DOER could support minor terminology modification to the straw proposal, particularly where they enable small project to directly benefit from simple distribution upgrades, even if they are subject to supplemental review.

iii) How would such a fee interact with the system planning process described in Section II? Should fees collected from Facilities using the simplified interconnection process be used to offset the costs of Capital Investment Projects approved through the proposed distribution system planning process?

Regarding the interaction of the fee and the system planning process, Unitil states that "the Common System Modification Fee and the CIP fee are two different fees covering different system costs."[92] It further recognized that the distribution planning process would not include analysis of a service transformer to the customer, which would be the limit of the equipment covered by the Common System Modification fee.[93] This aligns with DOER's position as provided in its initial comment. However, there is one type of distribution system upgrade project that could be categorized as either the CIP or the CSM and therefore, if categorized as a CIP, could imply that such CIP projects would need to be identified through the distribution planning process. This occurs where the aggregate impact of simplified projects results in System Protection upgrades.[94]

Since most of the distribution upgrade projects are distinctly either a CIP or a general system upgrade whose costs could be recovered through a CSM, from the planning process

[91] NGRID Initial, p.28, FN19.
[92] Unitil Initial, p. 11.
[93] *Id*.
[94] *See* Unitil Initial, pp. 4-5 (identifying System Protection upgrades to include modification or addition of system protection devices and schemes, ground overvoltage protection for reverse power flows, direct transfer trip, switchgear addition or replacement, field communications, and SCADA addition).

perspective, the two types of distribution upgrade projects merit different pre-approval processes. DOER continues to support that the Department treats these projects by "type" so that the beneficiaries are clear. The classification of these distribution upgrade projects will help ensure that the EDCs can respond quickly to simplified interconnection requests while certain CIPs would need to be identified through the distribution planning process. DOER's position aligns with the National Grid proposal that recognizes that "the annual budget described above [for CSM Simplified fees] would not identify specific sites but would be available to all simplified applicants that paid the Small DG CIP Fee …".[95]

With regards to the Department's second question on whether fees collected from Facilities using the simplified interconnection process should be used to offset the costs of CIPs, National Grid proposes potential over-collection of Simplified CSM could be put toward CIPs.[96] This aligns with DOER's initial comment proposal which stated that the any funds collected, but not used, to pay for distribution upgrades to support simplified projects will be put toward CIPs[97]

b) Expedited and Standard Facilities

i) Is a minimum Common System Modification Fee appropriate?

The EDCs recommend Expedited and Standard Facilities not be subject to a CSM fee. They argue that the CIP would be a more appropriate designation for distribution upgrade facilities needed to support Expedited and Standard Facilities and therefore the CIP fees would be the more appropriate mechanism to recover the costs associated with the necessary distribution upgrades.[98] The EDCs also state that a CSM applied broadly to Expedited and Standard facilities would distort

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[95] NGRID Initial, p. 30.
[96] *Id* (referring to the 150% rollover provision).
[97] DOER Initial, p. 28.
[98] Unitil Initial, p. 11; NGRID Initial, p. 32; and Eversource Initial, p. 25.

the price signal established by CIPs.[99] However, the EDCs have not demonstrated that the CIPs will comprehensively meet all of the necessary system upgrades to integrate DG under the Expedited and Standard interconnection processes. DOER continues to support the use of a CSM Fee for Expedited and Standard facilities as there may be necessary distribution system upgrades either not recovered by, or not well suited to the proposed CIP design. Having a way to pay for distribution upgrades that otherwise would not be developed under the processes to identify CIPs will help ensure that these upgrades are not delayed. Additionally, DOER disagrees that a CSM fee for Expedited and Standard facilities results in a distorted price signal. Instead, the CSM will help pay for distribution upgrades that provide benefits to certain interconnecting customers.

First, under the Department's existing proposal, a ground fault overvoltage ("3V0") solution would only be proactively deployed to address System Protection Constraints if it were part of a larger-scale CIP project. However, addressing System Protection Constraints with 3V0 outside of a large-scale upgrade on a proactive basis can result in significant additional hosting capacity. Establishing a CSM can help achieve that end because projects will pay a CSM fee which EDCs can use to pay for common upgrades as the need arises.

Other common projects that could enable expanded DG hosting capacity may not be included in the CIP unless part of a larger project, such as load tap changer ("LTC") and controller upgrades. If these common investments are not CIP-eligible they will not occur on a proactive basis, even though they may be needed for many or most Expedited or Standard interconnection requests. If these distribution upgrades are triggered by certain interconnection applications, all interconnecting DERs and DG triggering applicants would not financially contribute toward the

[99] Unitil Initial, p. 11; NGRID Initial, p. 33; and Eversource Initial, p. 26.

upgrade, leaving the individual applicant to pay the full costs of the upgrade, and resulting in deployment delays. A CSM Fee may help resolve this type of situation by requiring all interconnecting facilities contribute toward these common required upgrades, helping the EDCs make such investments proactively.

Second, under DOER's proposal, a CSM will not distort price signals. Rather, a CSM will establish a fee for interconnections by providing a price signal that recognizes that some DG interconnections impose system costs. In its comments, National Grid recognizes the value in establishing a "clear price signal that even small Facilities impose operation costs on the distribution system" through a CSM for Simplified facilities that currently pay no interconnection costs.[100] Establishing a CSM for Expedited and Standard facilities accomplishes a similar outcome. However, DOER believes that such a fee should not be set so high as to discourage DG or DER development when the benefits outweigh the system costs that the DG or DER imposes.

Similarly, as designed by DOER, a CSM can help to reduce the risk that a CIP Fee will be so high as to create a price signal that deters DER or DG deployment which in turn can result in unused CIP capacity after the distribution upgrades have already been made. The challenge will be to identify CIPs that can reasonably be allocated to specific interconnecting DG or DERs, compared to CSM-related distribution upgrades whose costs are more widely distributed to all other interconnecting DG and DERs.

(1) **Provide a proposed method for determining such a fee.**

The fee could initially be set on data already provided by the EDCs in this proceeding and revised in a future investigation.[101] As noted above, data suggests the Simplified CSM fee

[100] NGRID Initial, p. 26.

[101] As noted in response to the Department's question 2.a.i above, the EDCs provides data regarding the cost of upgrades for DG interconnections.

should be established at $25/kW export capacity or fixed $100 per facility. Establishing the CSM immediately is important to ensure projects begin paying for the hosting capacity they use immediately. Thus, the Department should consider setting the fee at $25/kW export capacity or fixed $100 per facility with the intention of further investigating needed updates to the fee in the future.

(2) **Explain why the proposed fee levels are appropriate considering the level of investment required to support the types of investments the fee is intended to cover.**

Please refer to DOER's response to Question 2.b.i above.

(3) **Explain how the proposed fee establishes clear price signals, provides cost certainty, and limits ratepayer costs.**

Please refer to DOER's response to Question 2.b.i above.

(4) **Explain how such a fee would interact with the distribution system planning process described in Section II.**

The Department should categorize which types of constraints are recovered through CIPs and which types of constraints are typically recovered through CSM fees. The EDCs' initial comments noted that upgrades for simplified projects are distinct and different from bulk upgrades for increased capacity.[102] If the Department adopts a CSM Fee for Expedited and Standard facilities, it should clarify that some upgrades at the circuit and substation level are more similar to Simplified upgrades than they are to bulk system upgrades.[103]

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[102] Unitil Initial, p. 11; and NGRID Initial, p.30, FN22.

[103] Upgrades like 3V0 may be better suited to a process more like the Simplified CSM than to the CIP. For example, a $300,000 substation upgrade to enable 3V0 upgrades is far closer in value and replicability to an $8,000 service transformer replacement ($0.292M difference) than it is to a $50,000,000 substation reconfiguration ($49.2M difference). $8,000 generalized from NGRID Initial, Att. 1, <=25kW (Simplified Tab), cell J16. $300,000. 3V0 upgrade identified by Unitil in D.P.U. 19-55, Unitil Update 10-24-19, p. 1. $50,000,000 substation reconfiguration from National Grid Summary of Central/Western MA Part 2 Cluster Study Results, p.2, *available at* https://ngus.force.com/s/article/DG-Stakeholder-Updates (May 29, 2020).
CA, NY, and HI have encountered the need for similar upgrades and may be another source for potential available upgrades and costs. For example, $800,000 3V0 & LTC upgrade from National Grid NY REV Interconnection Demonstration Project Case 14-M-0101 Revised Implementation Plan October 19, 2018, where two substations cost

ii) Should Common System Modification Fees be based on nameplate capacity and/or export capacity?

If you propose that the fees be based on a combination of the two, please clarify how they should be weighted.

Above, DOER recommended establishing Simplified CSM fees at around $25/kW of export capacity, or in the alternative, fixing the Simplified CSM fee at or below $100/project. Similarly, DOER recommended the Expedited and Standard CSM fee could be established at the same $/kW export capacity price, and then adjusted in the future. This is a change in DOER's original proposal in response to numerous initial comments requesting fee simplicity.[104]

3. Department questions on AGO Proposal in 19-55

a. Attorney General's Power Control Limiting Program (Att. B-1, Att.)

i. Would eligibility for the Program be for (a) new Interconnecting Customers or (b) new and existing Interconnecting Customers?

ii. Identify equipment and software necessary for implementation of the Program and which equipment and software would be installed (a) at the Interconnecting Customer and (b) at the Distribution Company.

iii. Identify any amendments or attachments to the ISA that would be necessary to implement the Program.

iv. Request to the Distribution Companies a. Does the Company currently have the ability to implement the Program? If no, please explain what would be required to successfully implement this Program

The EDCs stated that static curtailment is already an integral component of system designs and ISAs (whether in the form of high DC to AC ratios, or software related export limits with corresponding relays).[105] DOER has a similar understanding, and consequently does not believe a static curtailment program would be worthwhile at this time.

b. Attorney General's Dynamic Curtailment Program (Att. B-1, Att.)

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a total $1.7M. The findings also supported additional upgrade types such as replacing CCVT equipment with optical VT to reduce construction time for 3V0 and switched-source technology to increase hosting capacity by diverting power to adjacent feeders.

[104] DOER initially proposed establishment of a fee on both nameplate capacity and export capacity.

[105] Eversource Initial, p.30; and NGRID Initial, p.36.

i. **Based on your understanding of the Program, identify equipment and software necessary for implementation of the Program and which equipment and software would be installed (a) at the Interconnecting Customer and (b) at the Distribution Company.**
ii. **Identify any amendments or attachments to the ISA that would be necessary to implement this Program.**
iii. **Requests to the Distribution Companies: a. Does the Company currently have the ability to implement the Program? If no, please explain what would be required to successfully implement this Program. b. Provide details on the flexible capacity pilot in NY (applicable to National Grid only).**

The EDCs' responses to the Department's questions above focused on EDC-controlled dynamic curtailments.[106] Eversource suggests that the opportunity cost of curtailment may be too expensive for a facility owner to accept.[107] The cost of solar and storage has declined dramatically over the past decade, and the declines are anticipated to continue.[108] As production costs decline, the cost of either curtailing and/or storing for later use declines, resulting in distribution system upgrade costs exceeding the cost of curtailment. DOER recommends that dynamic curtailment should be considered, either now or in the future, so that the benefits of distribution system upgrades can be compared to the cost of curtailing the DER output when the distribution system is constrained.

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[106] Eversource Initial, pp. 37-45; NGRID Initial, pp. 37-44; and Unitil Initial, pp. 17-20. It is important to note that alternatives may be found in dynamic rate design (such as proposed by DOER in D.P.U. 20-69, which is designed to increase load coincident with renewable generation), or dynamic interconnection costs as proposed by the AGO in its initial comment. AGO Initial, p. 8. These alternatives, which may be longer term options, seek to provide a price signal to reflect the real-time condition of the grid and enable resource owner/operators to optimize their system design and operations.
[107] Eversource Initial, p. 33-34
[108] DOER Initial, p. 18.

IV. CONCLUSION

DOER appreciates the opportunity to provide this comment and respectfully requests that the Department consider and adopt the recommendations made within DOER's initial comment and this reply comment, as it deems appropriate.

Respectfully submitted by,

THE MASSACHUSETTS DEPARTMENT
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