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February 5, 2021

By E-Filing

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Distributed Energy Resource Planning and Assignment and Recovery of Costs for the Interconnection of Distributed Generation – D.P.U. 20-75

Dear Secretary Marini:

On behalf of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), enclosed for filing is National Grid Reply Comments on Straw Proposal.

Thank you for your attention to this matter. Please contact me if you have any questions regarding this filing.

Sincerely,

Nancy D Israel

Nancy D. Israel, Esq.

Enclosure

cc: Katie Zilgme, Hearing Officer

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COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities On Its Own Motion Into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation	)	D.P.U. 20-75

NATIONAL GRID REPLY COMMENTS ON STRAW PROPOSAL

Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid" or the "Company") offers these reply comments to the Department of Public Utilities (the "Department") in response to the Department's October 22, 2020 Vote and Order Opening Investigation ("Order") requesting public comments on the Department's Attachment A straw proposal for a new distributed energy resource planning process and methods for the assignment and recovery of costs associated with the distributed generation interconnection process and system modifications needed for interconnection.[1]

I. INTRODUCTION AND PROCEDURAL HISTORY

Pursuant to its ratemaking authority under G.L. c. 164, § 94 and its superintendence authority under G.L. c. 164, § 76, on October 22, 2020 the Department opened an investigation into two issues for the electric distribution companies[2] (individually "EDC" and collectively "EDCs"): (1) distributed energy resource ("DER") planning and (2) the associated assignment and

[1] Capitalized terms that are not defined in these reply comments are defined in the Order, the Straw Proposal or the Standards for Interconnection of Distributed Generation, M.D.P.U. No. 1320.

[2] National Grid, NSTAR Electric Company d/b/a Eversource Energy ("Eversource") and Fitchburg Gas and Electric Light Company d/b/a Unitil.

recovery of costs related to the distributed generation ("DG")[3] process and infrastructure modifications needed to interconnect DG to an EDC's electric power system ("EPS").

On May 22, 2019, the Department opened Distributed Generation Interconnection, D.P.U. 19-55, to investigate the interconnection of DG in Massachusetts, pursuant to the Standards for Interconnection of Distributed Generation tariff ("DG Interconnection Tariff") and Distributed Generation Interconnection, D.P.U. 11-75-E (2013). Through the Department's decisions in D.P.U. 19-55, the Department has taken steps to improve the DG interconnection process in consideration of its objectives: (1) to preserve the safety and reliability of the EPS; and (2) to provide transparent and uniform technical requirements, procedures, and agreements to make interconnection as predictable, timely, and reasonably priced as possible. In D.P.U. 19-55, the Department solicited proposals with alternatives to the Cost Causation Principle that could be implemented in the near term. On February 28, 2020, the Department received proposals for cost assignment and cost recovery, including from National Grid.[4]

Through this Order, the Department proposes a new DER[5] planning process with the purpose of assessing optimal solutions for the interconnection of DG facilities, taking a long-term planning perspective. Also, the Department seeks comment on methods for the assignment and recovery of costs associated with the DG interconnection process and system modifications needed for interconnection. These proposals and requests for comment are presented as a Straw Proposal set forth in Attachment A ("Att. A") to the Order ("Straw Proposal"). On December 23, 2020

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[3] For the purposes of the Order and the Straw Proposal, the term DG refers to any type of Facility that must submit an application under an EDC's DG Interconnection Tariff, regardless of whether the Facility actually generates electricity (e.g., energy storage systems). Order at 1, footnote 3.

[4] The Massachusetts Office of the Attorney General, the Department of Energy Resources, Eversource, National Grid, the Northeast Clean Energy Council, and Pope Energy submitted proposals. These proposals are included as attachments to the Order and are referred to in the Order and herein as Att. B-1 through B-6, respectively.

[5] For the purposes of the Order and the Straw Proposal, the term DER includes 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). Att. A at 3, footnote 1.

initial comments in response to the Straw Proposal were filed by the Company and the other EDCs, Office of the Attorney General ("AGO"), Department of Energy Resources ("DOER"), Northeast Clean Energy Council ("NECEC"), Interstate Renewable Energy Council, Inc. ("IREC"), Pope Energy, Zero Point Development, Inc. ("ZPD"), and Solar Energy Business Association of New England ("SEBANE"). Low-Income Weatherization and Fuel Assistance Program Network, Blue Hub Capital and Melink Solar Development ("MSD") filed initial comments on December 17, 2020 and public commenter Sohil Thakkar filed initial comments on December 10, 2020.

Commenters proposed refinements to the Straw Proposal to provide for stakeholder input into the DER planning process, cost allocation for Common System Modifications that benefit all customers and cost allocation for simplified process Facilities. Commenters proposed certain additional refinements to the Straw Proposal, including with respect to operations and maintenance ("O&M") costs associated with System Modifications for Expedited and Standard Facilities.

The Company responds to initial comments in the context of the high saturation of DG in the Commonwealth and in its service territory in particular. Massachusetts has about 2,910 MW of installed solar and ranks eighth in the nation[6] and first in New England.[7] Currently the Company has about 1,580 MW of connected DG Facilities and 1,410 MW of pending DG applications for a total of about 2,990 MW connected and pending DG Facilities throughout its service territory. In recent years, the Company has seen an uptick in 1 MW+ projects and currently has 27 distribution substations with 15MW or more of DG saturation and 43 distribution substations with saturation between 5MW and 15MW.[8] As discussed in more detail below, as high DG saturation generally

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6 *State Solar Spotlight*, Massachusetts, Solar Energy Industries Association ("SEIA"), December 15, 2020.

7 *Electric Power Monthly, Table 6.2.B. Net Summer Capacity Using Primarily Renewable Energy Sources and by State, November 2020 and 2019 (Megawatts)*, U.S. Energy Information Administration.

8 See, e.g., *Distributed Generation Guidelines, National Grid Section 1.E.4 Report (February 1, 2021)*, The Company's Section 1.E.4 reports may be accessed on the Company's DG Stakeholder Updates website. These reports show saturation in certain substations and regions of the Company's service territory that indicate the potential need

requires System Modifications (and potentially transmission system upgrades) to interconnect any substantial amount of DG, clear price signals are essential to locating DG in the most cost effective areas, which generally also have shorter interconnection timeframes.

The Company's responses to stakeholder comments are further informed by National Grid's technical and practical expertise with studying the effects on its transmission and distribution systems of large aggregations of DG and designing and implementing solutions. The initial scope of the Affected System operator ("ASO") transmission study triggered by the high saturation of DG projects in National Grid's Central and Western Massachusetts ("C/W MA") service territory was 937 MW.[9] The distribution system Impact Studies associated with these projects showed the need for significant distribution infrastructure modifications to more than 20 substations in seven distinct geographic regions of the service territory, originally affecting approximately 480MW of the 937MW. The scope of these ASO and distribution studies were unprecedented in New England and required creative study planning and engineering solutions for National Grid's transmission and distribution systems to minimize the impacts of these large aggregations of DG. The Company currently is engaged in the distribution Group Study process in nine geographic areas in its C/W MA service territory. Transmission studies are expected to be required in addition to the distribution Group Study process, with details surrounding ASO study scoping and duration currently under development.

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for an ASO study that would affect three or more DG applications or more than 15 MW of DG capacity in the next six months. They do not include saturation from pending or connected MW of small (< 1 MW) DG projects. Saturation from pending and connected DG and the feeder level hosting capacity on the Company's distribution circuits is shown on the Company's *hosting capacity map*, which is updated monthly.

9 This study, known as the "Cluster Study," was carried out by the Company's transmission provider, New England Power Company, with input from nine additional Affected System operators. A focused ASO restudy of 529 MW was conducted subsequently.

II. RESPONSE TO COMMENTS

A. Stakeholder Input to DER Planning Process

The Department proposes to establish planning criteria, informed by stakeholders, for the 10-year rolling distribution system assessment. (Att. A at 4.).

Eversource, DOER, AGO, NECEC, and IREC supported stakeholder input in their initial comments as a general concept, with different visions of what that might entail.[10]

Since filing their initial comments, the EDCs have discussed what an effective stakeholder process might look like, including the steps in the planning process where stakeholders could provide meaningful input that would be incorporated into an EDC's overall system planning analyses, and are conceptually aligned as to where stakeholder input would be appropriate and where it would not. In particular, the EDCs are emphatic that stakeholders should have no input into developing or reviewing system planning criteria because the EDCs have sole responsibility to provide safe and reliable electric service in their service territories. National Grid opposes any stakeholder comments that suggest otherwise.

The three steps of the planning process where the EDCs anticipate stakeholders could provide meaningful input are forecast assumptions, plan development and a targeted review of the recommended plan.[11] These three steps, forecast, plan development and plan selection, are the steps in the Company's current planning process at which the Company solicits internal stakeholder input. The Company thinks aligning external subject matter experts' reviews with its existing internal consultation process would be the most efficient and useful approach. (The

[10] National Grid and Unitil did not address a potential stakeholder process in their initial comments.

[11] Each of the EDCs have their own planning criteria, which inform their respective planning processes, and may use different planning terminology. Conceptually, the EDCs agree on the parts of their respective planning processes where stakeholder input could be meaningful.

forecast step could engage a broader range of external stakeholders; only subject matter technical experts, however, would be appropriate for consultation at the second and third steps.)

Forecast Assumptions. As the EDCs have no visibility into where in the Commonwealth DG developers and customers plan to locate DG in the future, their intentions concerning the size of future proposed DG Facilities or the new technologies they foresee adopting and the timing of such adoption, stakeholders could provide meaningful input to the EDCs on these topics for the EDCs to incorporate into their forecast assumptions.[12] DOER also recommends stakeholder input into EDC forecast assumptions about technology type, size and location of DG. (DOER Comments at 15)[13] Stakeholder forecasting consultation could have two subparts: 1) consultation on the EDC's forecasting methodology; and 2) consultation on the EDC's forecast for specific area details. The Company suggests that the first subpart, consultation on the methodology, occur in advance of all planning efforts, with such methodology refreshed as or if the EDC determines necessary. (This first subpart of forecasting consultation is not shown in the flowchart below.) If the forecast methodology is reevaluated within each area study or planning effort, there could be significant inconsistencies. The Company suggests all stakeholders carefully consider this potential misalignment when considering what an effective and efficient forecast stakeholder process would entail. The second subpart, forecasting stakeholder consultation on specific area details, can occur within the area planning study scoping step, which is when National Grid would incorporate this subpart, as shown in the flowchart below.

[12] To address the land availability and permitting challenges to siting large solar arrays the Company identified in its initial comments, the Company suggests a separate process be developed at the state and municipal level to identify those locations where large ground mount solar projects could be constructed, as that would enable the EDCs to then work to provide needed capacity to those areas. This process could also identify incentives for municipalities to allow siting of such large projects.

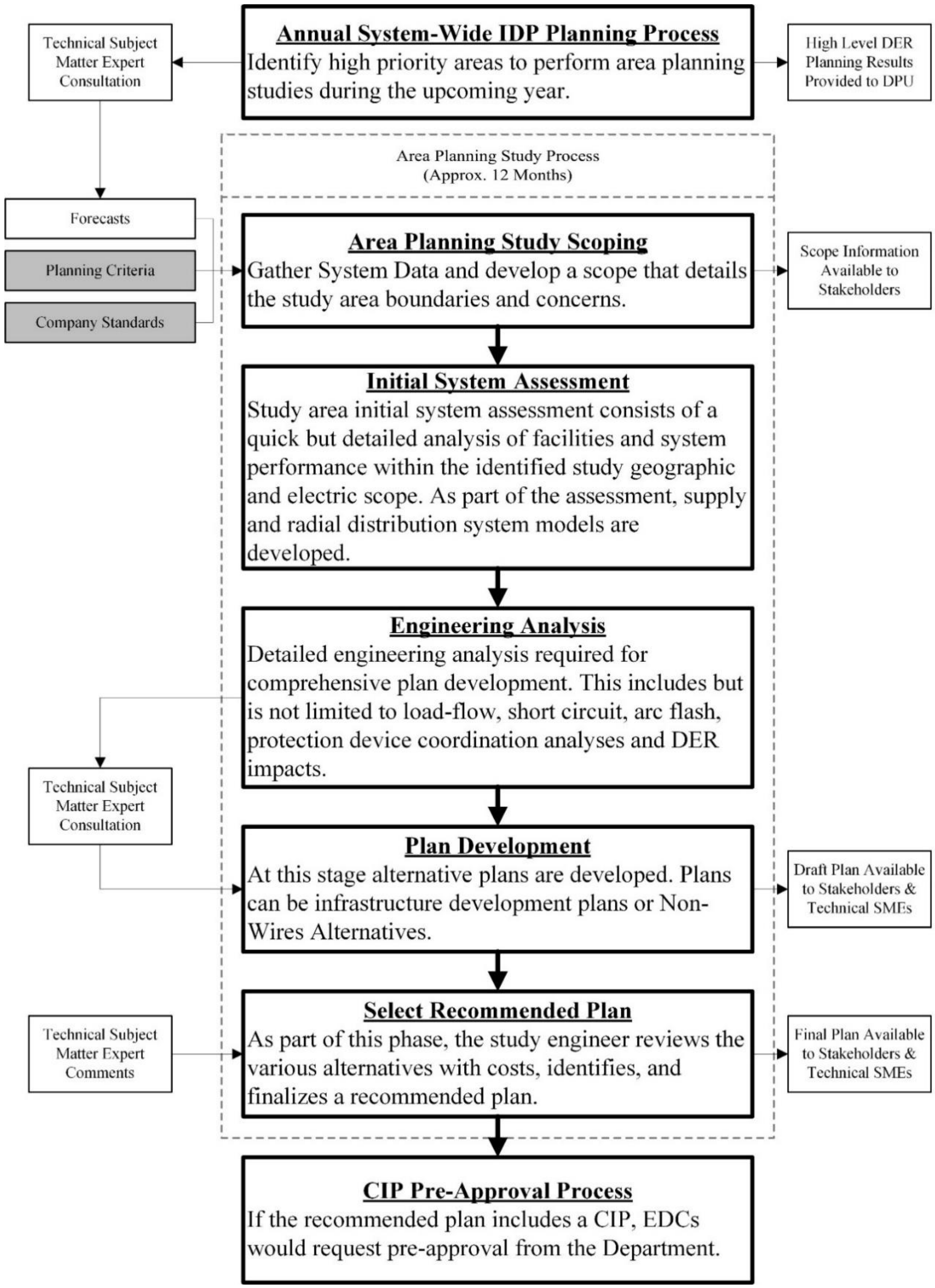
[13] DOER also proposes stakeholder input into system planning criteria and planning process outcomes, which the Company opposes for the reasons stated above. Id.

Plan Development. Plan development is the step in the Company's planning process at which alternative options for the plan are developed. When the Company has finished developing the options, the Company engages internal stakeholders to review the developed alternatives to ensure a suitable set of options are considered. The Company could consult with external subject matter experts in a similar manner.

Plan Selection. The third step within a study process for consultation is when the recommended plan is selected. At this stage, the costs of the options have been estimated and the Company has identified the least-cost, best-fit plan. The Company engages internal stakeholders to review the costs of all of the alternatives and describes the decisions that led to the recommended option for the plan and could engage external subject matter experts in the same matter.

The following flowchart illustrates the steps in National Grid's current planning process where an external stakeholder process could provide meaningful input to supplement the Company's existing internal stakeholder process and also illustrates how an IDP and any subsequent CIP proposals would fit into the existing planning process.

National Grid's Current Planning Study Process with Stakeholder Engagement Added



The Company's experience is that the process outlined in the above flowchart generally takes about 12 months. The proposed new stakeholder input described in these reply comments could significantly affect that schedule. National Grid expects to have a number of these planning efforts started at staggered intervals throughout the calendar year as system and DER development needs require.

The process the Company proposes integrates an external stakeholder process into the Company's well-developed existing planning process. Several stakeholders propose a wide-ranging stakeholder process that would go well beyond an engineering analysis and is unrelated to the EDCs' current planning processes.

AGO proposes a detailed and extensive process involving two separate stakeholder processes that would take two years and effectively would outsource the planning of the EDCs' distribution systems to stakeholders; this proposal is framed by AGO's vision of the future state of the distribution system. (AGO Comments at 4-6 and 14-20) The Company appreciates the effort AGO has put into visioning the clean energy future; however, the Company cannot accept third parties taking over the decision-making about the safety and reliability needs of its distribution (or transmission) system, the services it offers and how it charges its customers for those services.[14]

NECEC proposes that the Department and the EDCs establish a broad-ranging process to engage stakeholders in proposing, reviewing and approving cost recovery for CIPs.[15] (NECEC

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[14] The Commonwealth released its most recent plan and roadmap for the transition to a clean energy future in December 2020: Clean Energy and Climate Plan for 2030, which is open for public comment, and Massachusetts 2050 Decarbonization Roadmap.

[15] NECEC also suggests that the EDCs conduct quarterly (or other periodic) technical conferences to share planning studies and outcomes and receive stakeholder input and that the Department consider establishing a technical committee to provide input. (Id. at 13) The Company already holds periodic DG stakeholder update meetings at which it could share high level information about the planning studies and outcomes, as it does now for ASO studies. Under the Company's proposal, stakeholder input by technical subject matter experts would be incorporated into the Company's planning process.

Comments at 8) National Grid thinks it would be inappropriate to engage stakeholders in proposing, reviewing and approving cost recovery for CIPs because reviewing and approving cost recovery is the Department's responsibility.[16] The Company agrees with IREC that CIP Fees should be as cost effective as possible and would propose CIP Fees that reflect the cost of system designs determined by its planning process. (IREC Comments at 5) However, the Company disagrees with IREC's assertion that a stakeholder process to develop and approve the annual assessment or individual CIP proposals would be an effective means of attaining that goal, for the reasons explained in these reply comments. (IREC 10-11)

The challenge with an extensive and wide-ranging stakeholder process is the potential diversion of an EDC's time and resources from the business of interconnection (and inefficient use of stakeholders' time). Although stakeholders have provided valuable input on non-technical topics, the Company's experience in the study context is that external engagements have resulted in study inefficiencies. Aspirational or speculative scenarios expand the analysis tasks and can require remodeling, which extends the planning timeline. The multiple stakeholders can sometimes have competing interests with different desired outcomes. In other stakeholder engagements, competing stakeholder interests have resulted in requests to redo option selection and estimates and, in some cases, have circled back to challenge the original inputs of the study.

The facilitator will be critical to managing the stakeholder process, and National Grid strongly supports a technical expert serving as the facilitator. The facilitator will need to manage the parties to consensus on a reasonable set of forecast assumptions to minimize impact on the

[16] National Grid agrees with the process and responsibilities in the Straw Proposal for approving requests for cost recovery, which is solely the responsibility of the Department, and for Department pre-approval of cost recovery before an EDC begins a CIP. (Att. A at 5)

planning schedule. Strong facilitation also will be needed to drive the planning process to completion, building on the consensus from the previous steps.

To alleviate any potential stakeholder concerns about EDC bias in the facilitation during the initial implementation of the DER planning process, National Grid suggests that an appropriately qualified technical expert who has experience with utility systems planning in Massachusetts or in a state with comparable high DG saturation would best be able to manage such a stakeholder process. Because the system planning process is technical in nature, participation in the planning process should generally be limited to technical subject matter experts.

B. Common System Modification Cost Allocation for Expedited/Standard Facilities

In the Straw Proposal, the Department notes that although the CIP Fee portion of the Straw Proposal coupled with existing cost allocation structures (including Group Study) will be sufficient to address recovery of costs for interconnection of DG, the Department is willing to consider whether a Common System Modification fee may be beneficial to address any Common System Modifications not included as CIPs.[17] (Att. A at 8)

Eversource, DOER and IREC support the concept of a Common System Modification charge in addition to a CIP Fee. National Grid is conceptually aligned with Eversource's proposal to recover a return on and of capital for the portion of an EDC's DG-related bulk distribution substation level upgrades necessary to provide system reserve capacity for reliability and operational flexibility, because such upgrades benefit all customers.[18] The Company also is conceptually aligned with Eversource's proposal to collect that cost through the Reconciling

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[17] The Straw Proposal defines a Common System Modification as changes made to an EDC's electric power system that benefit more than one interconnecting Facility or customers at large. (Att. A at 1) The Company proposes alternative definitions in these reply comments.

[18] DOER also expresses support for allocating upgrade costs among DG Facilities and all customers according to the benefits they each receive. (DOER Comments at 20) The Company disagrees with DOER's proposed alternative approach of allocating fees based on a Facility's impact on the distribution system. (Id. at 19)

Charge. (Eversource comments at 22 and 27) However, National Grid notes that there are some differences in each EDC's planning criteria and manner of benefit assignment for system reserve capacity versus DG reserve capacity that are likely to result in different cost allocation outcomes across the EDCs, which the Company expects to discuss further in this process. Also, over time, the Company anticipates that the use of the Reconciling Charge for multiple beneficiary system upgrades will need to be revisited.

Instead of referring to such system upgrades as "common system modifications," which could be misconstrued as System Modifications that are common to members of a Group Study, the Company proposes the following more precise definitions for a system upgrade, which also identify who benefits and the appropriate cost allocation:[19]

- DG Reserve Capacity Improvements – EDC capital work (or alternative solutions) that incrementally improves the reserve system capacity for the interconnection of DG Facilities. This work would be derived from the EDC's planning analysis (in the Company's case, IDP analysis) through consideration of in-queue or forecasted DER or by an interconnection study. While this work has load serving capability, there is no load-based driver as a result of the studied forecast and the cost of this work therefore would be wholly assigned to DER through the CIP Fee mechanism and recovered via the Reconciling Charge in the interim.
- Multi-Value Improvements – EDC capital work (or alternative solutions) that provides both system safety and reliability and DER enabling needs for Expedited

[19] References to "DER" in these proposed definitions would apply to Expedited and Standard process Facilities, as the Company has proposed a simplified process common system modification fee. For ease of reference, the Company has not incorporated that distinction into the proposed definitions. Also for ease of reference, the Company continues to use the Straw Proposal term "Commons System Modifications" in referencing other commenters' initial comments.

and Standard Facilities.[20] This work would be derived through the EDC's planning analysis (in the Company's case, IDP analysis) in consideration of in-queue and forecasted DER or by an interconnection study. The cost of this work would be apportioned based on the incremental cost as a result of the DER analysis, with the incremental change in cost as a result of the DER allocated to the CIP Fee and the amount of the system improvement that benefits all customers allocated to the Reconciling Charge (and not recoverable by CIP Fee). An example of a Multi-Value Improvement would be a new transformer required for base-case system needs that is upgraded to the next size transformer to enable additional DG capacity. The cost of the base-case transformer would be allocated to recovery via the Reconciling Charge and the cost difference between the base-case transformer and the larger transformer to enable DG would be allocated to the CIP Fee.

The Department also solicitated comments as to whether any such Common System Modification fee should be fixed or capped.

It is critical to understand that there will be locations where DG is proposed that are in areas with high interconnection costs and in those areas, DG should receive the proper pricing signals to reconsider locating in lower cost areas. As noted above, higher interconnection costs reflect more significant System Modification costs (and potentially associated transmission

[20] In accordance with Section 5.4 of the DG Interconnection Tariff, National Grid does not charge DG Interconnecting Customers for capital work that is already in its capital work plans (which the Company refers to as "system improvements"). Under an IDP process, system improvements would be EDC capital work (or alternative solutions) that incrementally improves safety and reliability of the distribution system. This work would be derived through IDP analysis in consideration of forecasted load growth, reliability or asset concerns. While this work would have DG serving capability (hosting capacity), the system needs driver results in this work would be wholly designated as a capital investment that is recoverable through the Reconciling Charge.

upgrade costs), which generally translate into a longer interconnection timeline because of the longer construction timeline.

As the Department noted, a fixed fee for all Expedited/Standard System Modifications likely would not provide an effective cost signal regarding the location and need for the investment and a ceiling on such a fee could impose significant costs on customers if the ceiling were set too low. (Att. A at 12) National Grid agrees with the Department's concerns, as did many other commenters. DOER questions the need for a cap given the pre-approval for capital investments and the associated cost review; DOER also cautions against potential gaming of $/kW price signals. (DOER Comments at 26) IREC does not recommend a cost ceiling and although IREC recommends a fixed $/kW approach, IREC acknowledges the drawback that a fixed fee would not provide locational price signals. (IREC Comments at 14-15) Eversource and Unitil oppose the elimination of price signals through caps on Common System Modification Fees (Eversource Notes at 25-26, Unitil Comments at 11).[21]

NECEC argues for an arbitrary cap of 30 percent of the actual costs with a further restriction of $300/kW up to a total of $1.5 million on the cost allocation of any capital improvements that benefit more than a single Expedited/Standard applicant, whether those costs are captured through a CIP Fee or a Common System Modification Fee. (NECEC Comments at 15-16) National Grid strongly opposes NECEC's proposal. An arbitrary allocation through a percentage or $/kW limit that is detached from any engineering and financial judgment by the EDC would allocate costs without regard to who caused the cost (the traditional Cost Causation Principle that underlies the CIP Fee) or who benefits (the alternative cost allocation approach for

[21] National Grid also supports price signals for an Expedited/Standard Common System Modification Fee. (National Grid Comments at 34). To avoid confusion, the Company's concerns about such a fee in its initial comments would be resolved by a properly designed Expedited/Standard common system modification fee as defined and described in these reply comments.

Common System Modifications for Expedited/Standard Facilities, and for simplified Facilities, supported in these reply comments). Similarly, NECEC's proposed arbitrary cap of $1.5 million on the total cost per Expedited/Standard application could have the perverse result of encouraging DG developers to propose the largest possible system designs to take advantage of the "free" kWs once the $/kW cap has been exceeded, which would be shifted to all customers.

C. Cost Allocation for Simplified Process System Modifications

Although historically it has been rare for Facilities interconnecting under the simplified process to trigger or pay for System Modifications, this has been changing with the high saturation of solar, which, as the Department has noted, increasingly is adding unanticipated significant costs and delays to the interconnection of simplified Facilities. (Att. A. at 10) The Department has hypothesized that an upfront simplified process Common System Modification fee could offset the costs of System Modifications these Facilities may trigger, provide greater predictability to interconnection costs and timing for such Facilities and send a clear price signal that even small Facilities impose operational costs on the distribution system, particularly given the high saturation of DG. (Id.) The Department invited comments on establishing a Common System Modification Fee for simplified Facilities.[22] (Id. at 10-11)

There is broad support for establishing a Common System Modification Fee to offset the costs of System Modifications for which Facilities interconnecting under the simplified process may collectively contribute to the need, such as transformer upgrades.[23] All of the EDCs supported such a fee in their initial comments, as did DOER, NECEC, IREC, SEBANE, and Pope Energy.

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[22] In its initial comments, the Company suggested calling this fee a "Small DG CIP Fee." (National Grid Comments at 28, footnote 19). Like the changes to terminology the Company proposed above for common system modification fees applicable to Expedited and Standard Facilities, calling the common system modification fee applicable to simplified Facilities by a more precise name would minimize confusion.

[23] For the reasons explained in its initial comments, National Grid supports such a fee for simplified applications served by a radial distribution feeder. (National Grid Comments at 26)

The Department noted that the fee could be set in a way that provides cost certainty, for example, by a fixed $/kW charge or a flat fee. (Att. A at 10-11) The commenters who addressed the methodology of setting a fee generally agreed with this concept. National Grid (Comments at 27) and Unitil (Comments at 10) support a $/kW fee. National Grid proposed a detailed methodology for setting such a fee. (National Grid Comments at 26-31) IREC supports a fixed fee as the fairest approach; however, as discussed below, IREC proposes to exclude certain simplified Facilities from this fee. (IREC Comments at 11) SEBANE supports a fixed fee with a cap that reflects the cost of interconnection. (SEBANE Comments at 5)

NECEC proposes a fixed fee of $20 per kW capped at $500 but provided no rationale for those figures. (NECEC Comments at 19) Pope Energy supports a flat fee of $150 or $300 based on size categories. (Pope Energy Comments at 18) National Grid, by contrast, proposes establishing a set $/kW fee that captures the projected actual costs of System Modifications triggered by simplified Facilities, which would likely be different for each EDC and could vary year-to-year based on levels of simplified DG saturation. To limit the overall cost of the program annually, the Company also proposes the fee would represent a minimum cost to simplified applicants with a cap on the actual costs per application covered by the fee (up to a fixed amount representing the typical cost for such minor System Modifications) with the applicant covering any costs above that amount as a direct System Modification payment in rare scenarios.[24] (National Grid Comments at 27) Although National Grid has not yet calculated the specific amount of the $/kW fee or cap on applicant costs covered by the fee (which would be dependent on the final scope of the program identified by the Department in this docket), setting the $/kW fee or an

[24] In its initial comments, National Grid noted that for illustrative purposes the $/kW fee might be in the range of $25-$50 per kW, depending on saturation, up to a fixed amount of $5,000. (National Grid Comments at 27, footnote 27)

overall cap on the fee charged per applicant to participate in the program (as NECEC proposes) or a flat fee per application (as Pope Energy proposes) that is too low would undermine the purpose of establishing a unique method for allocating the cost of System Modifications triggered by simplified Facilities because it would either shift program costs from larger simplified Facilities (that naturally exceed the cap by size and are also mostly like to trigger System Modifications) to smaller simplified Facilities or to other customers.

DOER alone proposes a variable fee based on the relative impact of the simplified Facility on the distribution system, to substantially decrease the fee for Facilities with minimal exports and to waive the fee where there are "clear benefits" of continued DG growth, a concept DOER did not explain. (DOER Comments at 27)

DOER's proposal for a variable fee effectively would obviate the benefits of a unique Common System Modification Fee for simplified projects because it would assess the impact on the distribution system of each simplified Facility individually, rather than sharing the cost of System Modifications that are triggered by simplified Facilities collectively in a fair way among all simplified Facilities. Such a methodology also would be administratively complex to implement. National Grid also opposes DOER's proposal to waive fees for simplified Facilities by perceived locational benefit. Until all lower cost areas have been exhausted, the EDCs should not be providing incremental subsidies for interconnection costs for higher priced DG projects. Furthermore, if such a proposal were approved, it would substantially increase the administrative complexity for screening and managing simplified applications, which runs counter to the simplified process purpose of providing rapid conditional approval of simplified projects. This proposal also would result in higher fees for simplified applicants in locations where the fee was imposed because the costs across an EDC's service territory would be spread across fewer applicants. From an implementation perspective, it would be very difficult to define a geographic boundary around locations where DOER perceives “clear benefits of continued DG growth” because even if such an area could be defined, given the high level of DG saturation throughout the state there likely would still be concentrated pockets of saturation where an individual simplified applicant would trigger minor System Modifications and a cost allocation methodology would need to be determined for such situations.

National Grid opposes IREC’s proposal to exclude non-exporting simplified Facilities from a simplified Common Systems Modification fee. (IREC Comments at 11) Although National Grid agrees that export capacity should be taken into account in determining the $/kW fee for simplified applicants, it should not be the sole factor in determining the fee. IREC’s proposal to set a per-project fee by dividing the previous year’s upgrade costs attributable to simplified Facilities by the number of such projects in that year and adjusting the fee annually to ensure there is little over or under payment by such projects as a whole is aligned with the Company’s proposal. (IREC Comments at 12, National Grid Comments at 27-28) The Company also agrees with IREC that the fee is likely to be reasonable using this approach. (IREC Comments at 13)

D. Additional Commenter Recommendations

<u>O&M</u>

ZPD makes recommendations about the methodology for calculating O&M costs for system upgrades that would be passed through to DG Facilities. (ZPD Comments at 2) NECEC proposes rate-basing such O&M costs. (NECEC Comments at 18)

The DG Interconnection Tariff provides for an O&M fee for Expedited and Standard Facilities to cover an EDC’s carrying charges on the incremental costs associated with serving the Interconnecting Customer. (DG Interconnection Tariff at Table 6 and Note 6) The methodology for calculating that cost has yet to be determined, in part because the cost of System Modifications was relatively low before DG saturation necessitated significant upgrades to the distribution system.

Given the high and increasing DG saturation in the Commonwealth, the Company agrees with ZPD and NECEC that it is timely to address the method of calculating an O&M fee for Expedited and Standard Facilities.

The Company would support the Department opening a docket or establishing a working group to develop a proposed methodology for calculating O&M costs and an O&M fee for Expedited and Standard Facilities.

Dynamic Curtailment Pilot

In its initial comments responding to the Straw Proposal questions concerning AGO's proposed shorter term solutions, National Grid opined that after the infrastructure for dynamic curtailment has been developed, dynamic curtailment could be a useful interconnection tool in certain circumstances, such as in areas of moderate DG saturation, and noted that the Company has begun exploring dynamic curtailment for potential use in the DG interconnection process.[25] (National Grid Comments at 38) The Company identified two pending pilot projects, one in Massachusetts and one by its New York affiliate, to explore in more detail whether, how and in what circumstances it might be able to use dynamic curtailment as a tool to facilitate the DG interconnection process. (Id. at 43-44)

The Company reiterates its support for pilot investigations of the potential uses of dynamic curtailment and is pleased to note that AGO reiterated its support for moving forward in the near term with a dynamic curtailment pilot. (AGO Comments at 19, footnote 37) Eversource also sees

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[25] National Grid also agreed with AGO that power control limiting (static curtailment) is a useful tool in certain circumstances, which the Company currently uses in the interconnection process.

potential value in dynamic curtailment as a tool in targeted circumstances, such as for small to medium capacity deficits, and fully supports AGO's further investigation of dynamic curtailment and any future potential pilots to further evaluate the concepts, challenges and possible solutions.[26] (Eversource Comments at 38) NECEC similarly conceptually supports the potential use of dynamic curtailment (and of static curtailment) as a tool in specific limited circumstances (NECEC Comments at 26), as does IREC (IREC Comments at 16).

Eversource supports the AGO's purpose and intent for AGO's proposed dynamic curtailment pilot; however, Eversource foresees challenges, primarily with the overall cost to benefit ratio of such a program. Eversource also notes that due to the overclocking of PV installations in its service territory, dynamic curtailment would need to actively manage Eversource's system hundreds of days a year in DG saturated areas of its territory. (Eversource Comments at 37)

In December 2019, the Electric Power Research Institute ("EPRI") released a white paper, "Maximizing DER Hosting and Grid Utilization Flexible Interconnection Capacity Solutions," which detailed promising results. In particular, EPRI had modeled five feeders, covering 1,000 feeder locations, and found improvements in hosting capacity, ranging from 30 percent to 300 percent. Several factors, including the DC to AC ratio, the location of DER on the feeder and the region of the United States where the project is installed, accounted for this high range.[27]

As discussed in its initial Comments, National Grid also foresees challenges and has commissioned EPRI to assess representative feeders on the Company's distribution system to

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[26] Eversource's initial comments provide details about the limitations of dynamic curtailment (and of static curtailment) in areas of high DG saturation. (Eversource Comments at 34 and 37-38)

27 Details regarding EPRI's analysis and results are available through a public webinar: **"**Evaluating Dynamic, Flexible Interconnection Options for Distributed Photovoltaic Resources," NREL and EPRI (February 27, 2020). The discussion of the analysis starts at minute 26:40.

determine the constrained areas that potentially would be suited to a dynamic curtailment solution. EPRI also will analyze whether a dynamic curtailment paradigm would be an economically viable proposition for DG developers in the Company's service territory. (National Grid Comments at 42)

For the avoidance of doubt, National Grid supports pilot projects to explore the potential tool of dynamic curtailment in appropriate interconnection circumstances; National Grid is not suggesting that dynamic curtailment should be incorporated into the EDC planning process contemplated in the Straw Proposal nor factored into the determination of a CIP or a CIP Fee.

Performance Metrics

AGO and DOER propose performance metrics for the EDCs. AGO recommends that the Department require performance metrics for CIP utilization to reduce the risk of customers paying for enabled but unused capacity. (AGO Comments at 11) DOER proposes that the Department explore a performance metric that includes a financial incentive to the EDCs to identify and implement the most cost-effective solution for DG integration. (DOER Comments at 20-21)

The Company agrees conceptually with the goals AGO and DOER have identified; however, EDC performance metrics are neither necessary nor likely to be effective in achieving those goals because the EDCs are only one decision-maker in this process and have no control over third parties. By providing meaningful input into the planning forecast assumptions, including projected location of future DG projects, as the Company has proposed, stakeholders will help inform the EDCs' judgments about where infrastructure is needed to support future DG. By choosing to respond to price signals, DG developers can select a more cost-effective location. The Department will have oversight over EDC cost recovery. As part of the pre-approval process for the Reconciling Charge, the Straw Proposal requires an EDC to identify the cost of and kW capacity enabled by proposed CIPs, based on which the Department will establish a $/kW CIP Fee. (Att. A at 6) An EDC must obtain Department pre-approval for cost recovery for a CIP before beginning the project. An EDC must make a cost recovery filing on a different timeline demonstrating the prudency of its investment and to do so, the EDC will need to track and account for the cost of constructing the CIPs. (Id. at 5, footnote 3) Layering on performance metrics might increase the administrative burden on the EDCs; it will not add to the effectiveness of the risk mitigation built into the Straw Proposal.

For the above reasons, National Grid strongly opposes AGO's and DOER's proposals regarding performance metrics.

Export and Storage Tariffs

As a supplement to CIP fees and a Common System Modification fee, AGO proposes that the Department consider export tariffs and energy storage system import tariffs. (AGO Comments at 10-12) It is premature to consider such topics because as AGO acknowledges, planning and pricing for export capacity exceeds the EDCs' current capabilities and a $/kW fee is the best available cost allocation mechanism today. An import tariff could not realistically be investigated because as AGO also noted, the extent to which energy storage systems charge from the distribution system in Massachusetts is unclear. It also is premature to establish an export working group to investigate these issues, as nothing could be implemented at this time; moreover, both the EDCs and stakeholders will be devoting substantial resources to the stakeholder process described in these reply comments to address current issues and the Company, at least, does not have the resources to engage in a stakeholder process that would be an academic exercise at this time.

For the above reasons, National Grid strongly opposes AGO's proposals regarding export and storage tariffs.

Return on Equity ("ROE")

AGO also proposes that the Department reduce or eliminate ROE for the EDCs' investments in CIPs because AGO thinks the EDCs' risk of not recovering their costs is substantially lower under the Straw Proposal than it would be otherwise. (AGO Comments at 11)

The purpose of this docket is to plan for and allocate the costs of constructing the necessary distribution infrastructure to interconnect pending and forecasted DG. The EDCs cannot reasonably be asked to build out their distribution systems in advance for DG projects without earning a return on those investments that is the same as the return on all other investments in the distribution system. Moreover, an EDC may earn fair return on and of capital, which customarily is determined in rate cases. The return the Department approves is established on an enterprise-wide basis; it is not based on an analysis of the specific perceived risk associated with various classes of investment. Under the Straw Proposal, the EDCs will be compelled to invest capital on an accelerated basis to accommodate DER interconnections and therefore should earn a return on CIP investments like any other investment.

For the above reasons, National Grid strongly opposes AGO's proposal regarding ROE.

III. CONCLUSION

National Grid appreciates the opportunity to submit reply comments in response to the Department's request for comments on its Straw Proposal for a new DER planning process, methods for the assignment, recovery of costs associated with the DG interconnection process and System Modifications needed for interconnection, and looks forward to continued engagement on the issues the Department raised.

Respectfully Submitted,

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