nationalgrid

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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 Comments on Straw Proposal, including Attachments.

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.

Enclosures

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 COMMENTS ON STRAW PROPOSAL

Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid" or the "Company") offers these 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 comments are defined in the Order or in the Straw Proposal.

[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

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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 Atts. 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.

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").

II. GENERAL COMMENTS

National Grid's general comments on the Straw Proposal follow. In Section III the Company responds to the Department's specific questions.

A. National Grid Supports the Straw Proposal

National Grid supports the Straw Proposal and proposes certain modifications to facilitate implementation of its various components. The planning approach proposed in the Straw Proposal is essentially an integrated system planning process, which will accelerate and streamline DG interconnections. In addition, the proposed cost assignment and recovery mechanisms will provide greater cost certainty for DG interconnections and cost fairness for all customers. Taken as a whole, the Straw Proposal will enable more rapid deployment of DG, thereby furthering state climate and clean energy goals, including the achievement of net zero emissions by 2050. With respect to the two shorter term proposals by the Attorney General's Office ("AGO"), the Company agrees with AGO that power control limiting (static curtailment) is a useful tool and already offers power control limiting during the interconnection process. The Company also conceptually supports the dynamic curtailment approach as a potential solution in some limited circumstances and is investigating the potential uses of dynamic curtailment in the interconnection process.

B. Specific Proposed Modifications to the Straw Proposal

<u>Zone Concept</u>

The Straw Proposal provides that as part of the pre-approval process for the Reconciling Charge, an EDC would identify the incremental cost and incremental DG kilowatt ("kW") capacity enabled by proposed Capital Investment Projects ("CIPs"), based on which the Department would establish a dollar-per-kW CIP Fee for the EDC to allocate to each Facility that subsequently benefits from the CIP. Att. A at 6.

Similar to the Company's initial cost allocation proposal in D.P.U. 19-55, the Company would intend to establish zones for CIPs and the associated CIP Fees. The Company anticipates that it would establish zones that largely align with the Company's 48 planning areas, on an as needed basis as identified through its planning process. The Company would calculate CIP Fees in each zone net of the costs attributable to planned system improvements prompted by application of the Company's planning guidelines and assessments ("System Improvements") that would have occurred if no incremental DG capacity were proposed for development in that zone.[6] In addition, the Company would take account of allocations for improvements due to the DG upgrades that benefit all customers and kW capacity that is added for forecasted simplified project growth. Based on experience, the Company expects that different areas of its service territory would require different levels and costs of System Modifications to create capacity for known and forecasted DG interconnections, and thus would have different CIP Fees.[7] There could be cases in which the Company would have multiple CIP Fees in the same zone because the subsequent CIP(s) created additional incremental capacity. The Company proposes that CIP Fees should remain constant and fixed for the earlier of the enabled capacity being fully subscribed or the end of the proposed 10-year Reconciling Charge period. This will create better temporal fairness among DG Interconnecting Customers and will provide them more cost certainty as well.

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6 This aligns with National Grid's approach to determining the cost of System Modifications and with the separation of costs under Section 5.4 of the DG Interconnection Tariff.

7 The data National Grid submitted in response to the early information request in this docket and in response to question (2)a.i, show a minimum System Modification cost of $300 and a maximum System Modification cost of $1,354,311 for connected applications over 25 kW (i.e., the vast majority of projects subject to the Expedited and Standard tariff processes) over the roughly 10-year period of 2011 through October 2020.

Non-Bypassable Charge

The Straw Proposal indicates that the Reconciling Charge should be implemented as a non-bypassable charge, but also billed as part of distribution rates on customer bills. The Company notes that if the Reconciling Charge were to be part of the base distribution rate on customer bills instead of a separate line item on the bill, it would be bypassable and therefore would be avoided by any customer that was able to reduce or net their kWh usage to zero in a billing period through on-site DG (through the net metering or SMART Programs, for example). Instead, the Company recommends that the Reconciling Charge, like the Distributed Solar Charge ("DSC"), be shown as a separate line item on customers' bills and be calculated similarly to the DSC. Net metering customers who are not participating in the SMART Program are able to reduce their billed kWh to zero and avoid paying the DSC due to the lack of production metering on their DG, and this also would occur with the Reconciling Charge. Therefore, the Reconciling Charge would be bypassable for net metering customers, similar to the DSC being bypassable for net metering customers. The Company further recommends that the Reconciling Charge be excluded from the calculation of net metering credits. Finally, the Company respectfully requests that the Department consider changing the name from the generic "Reconciling Charge" to the more specific "CIP Factor" to avoid confusion as all costs recovered outside of base distribution rates are recovered through a reconciling charge.

C. Summary of National Grid's Current and Proposed Planning Process

As the Department has proposed a novel approach to distribution system planning for the interconnection of DG, the Company is providing a summary of its current and proposed planning approach for comparison.

Presently, the Company conducts routine planning analyses on its distribution system. The first component of this process is an annual capacity review of the entire distribution system that identifies capacity constraints considering both normal and system contingency operation and generates individual projects to address these constraints or identifies the need for a more detailed review. These more detailed reviews take the form of comprehensive area planning studies.

The Company annual capacity planning process identifies thermal capacity constraints and assesses the capability of the network to respond to contingencies that might occur. The capacity planning process includes the following tasks:

- Review of historical loading on each sub-transmission line, substation transformer, and distribution feeder
- Weather adjustment of recent actual peak loads as per the electric peak (MW)
- Econometric forecast of future peak demand growth as per the electric peak (MW)
- Analysis of forecasted peak loads with comparison to equipment ratings
- Consideration of system operational flexibility to respond to various contingency scenarios
- Development of System Improvement project proposals.

Individual project proposals are identified to address the issues identified by the tasks above. At a conceptual level, the Company prioritizes these project proposals for inclusion in future capital work plans. The annual planning process also forms the basis of the analysis provided in the Company's Annual Reliability Report.

The annual capacity planning process informs the prioritization of which area planning studies should be completed in a given year. When the annual capacity plan highlights an area that has capacity constraints at a level of severity/complexity where a detailed and comprehensive review is warranted, that area is identified as needing an area planning study. Other prompts for an area planning study include the identification of asset condition issues or a large new customer load request.

The area planning study process produces 15-year comprehensive plans for each area studied. The Company's Distribution Planning function considers an ideal refresh cycle for area studies to be five years. However, under current practices, National Grid typically does not initiate an area study unless significant system performance concerns are identified in the annual planning process or other acute concerns (e.g., significant load growth or asset condition concerns) are surfacing within an area. As such, efforts to execute or refresh an area planning study are most typically assigned when judged necessary by Distribution Planning leadership and update cycles are typically much longer the ideal five-year cycle suggested.

Given the Straw Proposal and questions the Department posed, the Company sees benefits to executing and maintaining what the Company, and other EDCs, would refer to as system-level Integrated Distribution Plans ("IDPs"). Consistent with the way capital project investment portfolios are assembled today, IDPs would consider the standard prompts for discretionary infrastructure development (e.g., maintaining system safety, reliability, and efficiencies) stemming from the aggregate impact of system load modifications and asset condition assessments with the application of Company-specific system planning guidelines.

It is National Grid's view that the transition to and development of a comprehensive IDP of the entire system will take several years to fully execute. Once developed, annual updates should be possible and revised system performance metrics will dictate when a comprehensive update to the area planning study for a portion of the Company's service territory (i.e., study area) is required. It should be noted that presently, the system performance metrics that would prompt a comprehensive long-range area planning study do not align with the study areas where the Company has experienced the most significant DG development interest. The majority of the most recently completed or nearing completion area planning studies cover the more urban topologies of National Grid's service territory due to average system loading and prevalence of asset condition issues within those regions.

The adoption of IDP techniques could begin with areas most recently studied but it is unlikely that DG developer interest will migrate to those locations. Moreover, any future IDP process, as discussed below in Section IV, will need to take into account long-term DG deployment goals, land availability and land use constraints in the distribution planning areas, and system operability planning concerns that would require coordination with transmission owners and ISO-NE.

Taking advantage of the structure and rigor of the current planning process, the Company would factor in proactive assessment of system performance impacts (concerns and benefits) prompted by DER adoption. Although this will be a major adjustment, it will be done on a strong foundation of critical problem-solving techniques.

The infrastructure development projects (i.e., projects that may be candidates the Company could propose as CIPs) ultimately identified within a system level IDP will be heavily dependent on load forecasting methodologies (including the need to forecast the impact of non-DG types of DER). It will take time to discuss and develop appropriate methodologies.[8] Initially, the Company may determine that to advance planning efforts, DG forecasts will simply anticipate future DG

[8] National Grid acknowledges that since the Department's Straw Proposal contemplates the EDCs proposing CIPs as the result of either the DER Planning Process or the result of interconnection studies, it is likely that National Grid would be able to propose some CIPs ahead of the full implementation of the IDP methodology. However, as noted in response to question (3)c.i., a clear path to grandfather and/or transition applications in the DG interconnection queue from the existing cost allocation methodologies into a CIP Fee structure would be necessary.

volume within defined study areas based on historical interest and development. Eventually, more sophisticated forecasts (for example, factoring in available land, land prices, community sentiment, etc.) will be required. The benefit of this approach is that the aggregate impact of non-complex DG adoption will be included in studies more clearly than in the past.

The IDP must be accompanied and informed by a transmission study on the same areas to be complete, useful, and truly integrated. However, the Company will need to work with ISO-NE to understand how such studies will be conducted and results will be preserved. Presently, ISO-NE reacts to DG applications over 1MW and provides the developer with a Facility-specific authority to interconnect. For an IDP to be successful and useful, the transmission infrastructure development required to support distribution infrastructure development that is driven primarily by forecasted DG must be able to be advanced before the Company has a clear understanding of specific DG applications for interconnection.[9]

Development of an IDP will best leverage holistic benefits of DER development and will be a key enabling step toward the use of dispatchable DER development in response to local system performance concerns during both system normal and contingency operations.

National Grid anticipates transitioning to an IDP through implementation of the DER Planning Process ("Planning Process") outlined in the Straw Proposal and strongly supports the Department's proposed distributed energy resource planning requirements.

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[9] As discussed below, New England states have begun a regional planning effort to better align the regional wholesale markets with the New England states' clean energy mandates.

III. RESPONSES TO QUESTIONS CONCERNING THE STRAW PROPOSAL

Pursuant to the Solicitation of Comments in Attachment A to the Order, the Company offers the following specific responses to the Department's questions concerning the Straw Proposal.

(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

National Grid agrees that the three items listed can address potential distribution system (and transmission system) needs for infrastructure investment in consideration of state clean energy and climate policy objectives, incorporation of DG investments, and development of associated planning criteria (as well as those stemming from loading modifications).[10] The Company understands the terms "Bulk Transformer" and "Bulk Station" in the context of the Straw Proposal to refer to any substation intended to accommodate distribution voltage class feeders for customer connections, that is, those terms are not limited to 230kV or higher bulk power system connections.[11]

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[10] As discussed above, implementing the proposed DER planning requirements will require closer prospective planning coordination between the Company, its transmission provider and ISO-NE, eventually resulting in an IDP.

[11] In general, National Grid recommends (in alignment with generally recognized industry practice and terminology) that to avoid any ambiguity for the remainder of this docket, the term "bulk" be reserved exclusively for descriptions of equipment (and EPS) that operate at transmission-level voltages, which may include (depending on the circumstances) substations and/or transformers that are supplied by a transmission circuit on the high-side but may serve distribution feeders and/or sub-transmission supply lines on the low-side. National Grid has worded its response in these initial comments to align with such a recommendation.

In addition to the above list, which is accurate but incomplete, National Grid identifies the following additional solutions to address potential distribution system needs:

- Distribution feeder addition, upgrade or replacement. More specifically, addition or modification of the series elements that make up distribution feeders and collectively establish their capabilities to serve DG Facilities (and load facilities), such as overhead conductors, underground cables, voltage regulators, capacitors, circuit breakers, poles, and fixtures. The rationale for these additional solutions is that as with the identified items for transformer and station work, distribution feeder work can enable additional DG capacity across the local EPS, especially in instances where reconfiguring distribution feeders allows existing DG capacity to be reallocated across nearby substations and/or substation transformers as an alternative to substation upgrades.
- Technologies for controlling DG (and more broadly, DER) export. These technologies (such as the Dynamic Curtailment Program proposed by AGO) would provide a means of actively managing DG site export by manual and/or automated feedback from the distribution system sensors and/or distribution system operators. In certain instances, this concept may allow for minimizing or eliminating the need for certain distribution System Modifications and reducing barriers to DG interconnection. This technology is tied to the need for system monitoring and status described below. Controlling DG export requires robust monitoring and control across the electric system. Once established, these technologies can be leveraged as a tool in system area planning.

- Technologies for active monitoring of EPS and DG status, which the Company cannot do today. This includes equipment to monitor customer and Company assets in real time. Currently, the EDCs use historical data for worst case load and electrical characteristics of the distribution system in order to plan for the required System Modifications to accommodate a specific site. Having full visibility of the system status would allow for real time adjustment and control of the distribution system, which could avoid the need for certain distribution System Modifications that would be required today. The planning and cost recovery elements of the Straw Proposal could help expedite enablement of these future state technologies.

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

Yes, transmission system performance assessment (studies) and associated transmission infrastructure upgrade costs needed to support interconnection of DG at the distribution level should be included in proactive distribution system planning for the following reasons.

The interconnected and networked nature of the entire EPS requires a comprehensive review. Planning for the distribution system includes consideration of substation expansion and/or new substation construction in order to accommodate projected DG growth. The distribution analysis would consider the most appropriate method of interconnection in accordance with the DG Interconnection Tariff. However, if the analysis were to be limited to the distribution system, a transmission constraint could be left unidentified, potentially leading to higher costs and longer study timelines. For example, a least-cost-to-serve distribution solution with an unidentified transmission solution could lead to an overall higher cost per customer. Or, if transmission constraints were identified after the distribution study had been completed, a distribution restudy could be required, followed by a transmission restudy, which would extend the overall study timelines.

Today, ISO-NE frequently requires transmission analysis, which is executed in the form of Affected System Operator ("ASO") studies. Since a transmission analysis is required in today's reactive planning process prompted by specific DG applications for interconnection, the Company suggests that any change from a reactive to a proactive distribution system planning process should include an associated transmission analysis, as noted in the General Comments above and in Section IV below. Otherwise, the effectiveness of any distribution level cost allocation plan will be significantly constrained.

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, and

iii. the appropriate method for cost assignment and recovery.

Yes, the distribution system assessment should identify projects that provide broader benefits beyond enabling incremental DG capacity.

Before discussing benefits, National Grid suggests that assessment inputs should be discussed. These inputs could include traditional load forecasts, as well as electric vehicle ("EV") and heat electrification ("HE") forecasts, asset condition information, and reliability performance information.

With a complete set of traditional and emerging inputs, a complete set of benefits or needs could be determined. For example, a project that enables incremental DG capacity could be built in a tree contact resistant manner to also provide reliability improvements. The same investment that enables DG under a light load scenario could enable EV charging and HE under a peak load scenario. Therefore, the set of suggested benefits are: DG enablement, EV enablement, HE enablement, and traditional system safety and reliability needs. Load shifting and load modifying inputs, such as energy efficiency and demand response, are not included in the list of inputs, as they can be considered solutions (or projects) to address the needs or enable the benefits.

The EV and HE benefits, if included as forecasted load additions, would be quantified as those enabled loads (which could be tied to cars or electrified homes). The traditional safety and reliability needs would be quantified in the typical manner.

An overall analysis resulting in comprehensive benefits provides for the most cost-effective electric system, but with challenges; specifically, cost assignment would be difficult. Consider a 40-year-old overhead line replaced with a larger conductor in a tree resistant fashion. That project could address asset condition, loading, contingency, reliability, DG enablement, EV enablement, and HE enablement issues and that project would create significant benefits for all customers due to its comprehensive nature. Cost assignment to each benefit, except through a simple percentage assignment, would not be possible. The Company has not determined an appropriate cost assignment method for integrated planning but is receptive to a variety of simplified methods that approximate cost causation principles without requiring overly burdensome calculation methods.

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.

National Grid opposes a cap on the dollar-per-kW billed to each Facility that benefits from the Capital Investment Project because that would undermine the Cost Causation Principle and cost transparency goals that underlie the concept of a CIP. A cap on CIP Fees would detach CIP Fees from the actual cost of System Modifications and permanently shift the cost of capacity additions that solely serve interconnecting DG customers to all customers because the costs above the cap would not be recovered through CIP Fee offsets to the Reconciling Charge.

A cap on CIP Fees also would undermine the economic signals the Department intends to send through CIP Fees. A CIP Fee provides a clear price signal to DG developers that aligns DG interconnection costs and the cost of enabling incremental DG capacity in a particular area: in areas saturated with DG relative to load and/or EPS hosting capacity, costs will likely be higher, while in less saturated areas, costs will likely be lower. This price signal, combined with the information about DG saturation in a particular area available to DG applicants,[12] should increase the likelihood that DG developers who choose to locate their projects in saturated areas can perform their own financial analysis to determine whether their projects are financially viable notwithstanding the potentially higher cost of interconnection. Further, the dollar-per-kW CIP Fee will provide more cost certainty, which should assist developers in securing financing. Conversely, developers of DG projects that would not be economically viable in areas with high costs would be guided to lower cost interconnection areas through such price signals.

The Company will use its Planning Process to determine where and when to establish CIP zones in which new and in-flight DG applicants would be required to pay the associated CIP Fee. There may be areas of the EPS that are inappropriate for the CIP concept because the cost of the required System Modifications is too high to be economically viable for any DG applicants. If a CIP zone and associated CIP Fee is established, the CIP Fee will be an important data point for DG developers to consider in deciding where to apply to interconnect their proposed Facility.

[12] This information is available through the EDCs' hosting capacity maps, reports identifying areas with pending or potential ASO transmission studies, and pre-application reports. See D.P.U. 19-55-C and D.P.U. 19-55-D.

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.

The format of an integrated planning assessment should begin conceptually with the standard distribution planning processes. This provides a proven foundation using a critical thinking problem solving format. The framework below describes the standard process and how integrated planning concepts could be incorporated.

1. Annual Planning

Annual planning generally covers three main topics: loading, reliability, and asset condition. The loading analysis presents the most opportunity to include integrated planning concepts and is described below. Annual reliability and asset condition reviews are expected to remain largely unchanged. The details of the inputs and outputs of normal and contingency loading that National Grid recommends for inclusion in the annual planning process are described below. In summary, DER inputs could be included into annual planning load analysis efforts, but with compounding effort and resource requirements.

Inputs

A yearly high-level system-wide loading-based screen is conducted to prioritize more detailed efforts. This effort is designed to include simple inputs to enable the wide area analysis. The traditional inputs include:

- Area electrical characteristics (feeder, substation, and supply line)
- Area peak loads (date, time, and value)

- Load forecast with energy efficiency (EE), distributed generation (DG), and electric vehicle (EV) inputs as load modifiers to the peak value. These forecasts include some regional differences.

In consideration of evolving integrated planning needs, the following information could be added or changed:

- Area light loads (date, time, and value)
- Separate forecasts to be obtained for base load, EE, DG, EV, and heat electrification (HE) inputs as load modifiers to the peak value. These forecasts include some regional differences.
- EV and HE existing and in-queue information when possible
- Existing Demand Response (DR) programs
- Existing energy storage system (ESS) locations and amounts.

<u>Outputs</u>

The traditional peak inputs and single forecast (including multiple technologies/factors) are used to analyze feeder, substation, and supply line normal configuration and contingency loading. The output is in tabular spreadsheet form.

In consideration of integrated planning concepts, load based annual planning could be modified to include light load (maximum generation) normal configuration loading.[13] This alone would effectively double the analysis. The application of separate forecasts by technology could also add additional analysis burden and needs to be carefully considered. Each forecast, if analyzed

[13] Because DG currently is disconnected in contingency situations, light load (maximum generation) contingency analysis is not necessary.

independently, doubles the analysis. National Grid suggests a cautious approach to multiple forecasts in annual planning efforts.

As described in "Summary of National Grid's Current and Proposed Planning Process" above, the completed annual plan information is used to prioritize the comprehensive area studies. While National Grid expects that concentrated load and asset needs will continue to drive area study efforts around urban centers, the inclusion of integrated planning concepts in annual planning will certainly drive the need for studies in the more rural portions of Massachusetts.

2. Area Studies

Area studies are used to thoroughly define project scopes (also known as System Improvements) that satisfy the needs of the electric system and expectations of all stakeholders (especially traditional retail customers). Specifically, they enhance the Company's ability to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs.

Inputs

The area studies consider the following topics and inputs:

- Normal and Contingency Loading – Annual plan data (peak data and forecast) for feeders, substation, and supply lines are entered into detailed system models to obtain nodal loading information. DG existing and in-queue locations and amounts are gathered. Separate models are created for distribution feeders and substations and supply lines.
- Voltage Performance – Voltage control settings and equipment details are gathered and entered into the same detailed models developed for the loading analysis. The models are used to obtain nodal voltage performance information.

- Reliability Performance – Three year or five-year reliability indices information by feeder is obtained and compared against averages and regulatory targets. Where necessary, detailed historical outage data is obtained.
- Asset Condition – Ad-hoc line and station asset condition reviews are obtained from subject-matter experts.
- Reactive Compensation / Power Factor – Capacitor control settings and equipment details are gathered and entered into the same detailed models developed for the loading analysis. The models are used to obtain nodal reactive power flow information.
- Fault Current/Arc Flash – For distribution feeders, the same detailed models developed for the loading analysis are used to obtain fault current and arc flash information at protective devices. For substations and supply lines, a different detailed system model is developed.
- Protection Coordination – Protective settings and equipment details are gathered and entered into system models. For distribution feeders, the same detailed models developed for the loading analysis are used to determine protection coordination issues. For substations and supply lines, a different detailed system model is developed.

3. <u>DER Planning (Future State)</u>

As described above, models are used to determine the detailed system issues and needs in an area. The same models would be instrumental in analyzing DER impacts and opportunities. The same voltage control, capacitor control, and protective device controls are necessary for DER evaluation. Therefore, the area study process to identify System Improvements provides a suitable framework for integrated planning. As DER planning does not yet exist, the inputs are likely to evolve.

Inputs

The inputs (for DG initially and subsequently for all DER) could include:

- Transmission loading and equipment settings similar to the distribution information described above. In certain cases, this information would be included in the same models used by the distribution analysis. However, certain transmission analysis needs will require other system models.
- Gather separate forecasts for load, EE, DG, EV, HE, DR, and ESS. Gather 8760-hour yearly load cycles, if available, for each technology, subject to the caveats noted above. If necessary, default load cycles can be used.
- Forecasts need to consider locational aspects, so the DER can be modeled accurately.
- EV and HE existing and in-queue information when possible
- Existing Demand Response (DR) programs
- Existing DG, including locations, capabilities, and amounts of large ESS.

The additional inputs described above would represent a major increase in resources and effort. In some cases, existing modeling software cannot reasonably incorporate 8760-hour data. It is recognized that yearly load cycle analysis is important for DER enablement; however, this would be a manual and labor-intensive effort for at least a few years until data handling, computing power, and existing software had been sufficiently upgraded. National Grid is currently working with its software providers to add functionality.

Outputs

Once the needs and opportunities were identified based on the inputs, comprehensive alternatives would be developed. Integrated planning may require additional analysis and thereby additional alternatives for specific technologies to allow for cost allocation. For example, issue identification could be completed with and without the DG forecast. In this manner, a set of solutions would be developed to address electric system safety and reliability and additional solutions developed for the forecasted DG.

The additional solutions would be cost allocated to the DG customers in a manner to be determined, potentially through CIP Fees. It is important to recognize that the "with" and "without" analysis could result in a "none," "some," or "all" outcome. To explain, a "with DG" analysis could show no additional infrastructure is needed over a "without DG" case, meaning that all of the forecasted DG is enabled by the System Improvements and there are no System Modifications to be cost allocated to DG customers. Alternately, a "with DG" analysis could show additional infrastructure is needed to enable all the DG over a "without DG" case, meaning that none of the forecasted DG is enabled by the System Improvements and there are many System Modifications to be cost allocated to DG developers. Last, there could be cases in the middle where some DG is enabled by the System Improvements and some is cost allocated to the DG customers; conversely; some System Modifications required by DG customers also could create benefits for load customers.[14] Each "with" and "without" case creates an additional analysis

[14] In the latter event, the Company may determine to not include the portion of the System Modifications that enabled benefits to load customers in the CIP Fee numerator, and such portion of the capital investment would be be recovered directly through the Reconciling Charge. National Grid expects that an IDP pilot implementation of these concepts would allow the Company to better understand which methods of cost allocations would be most appropriate in unique circumstances.

burden. National Grid suggests that only DG be analyzed in a "with" and "without" manner at this time.

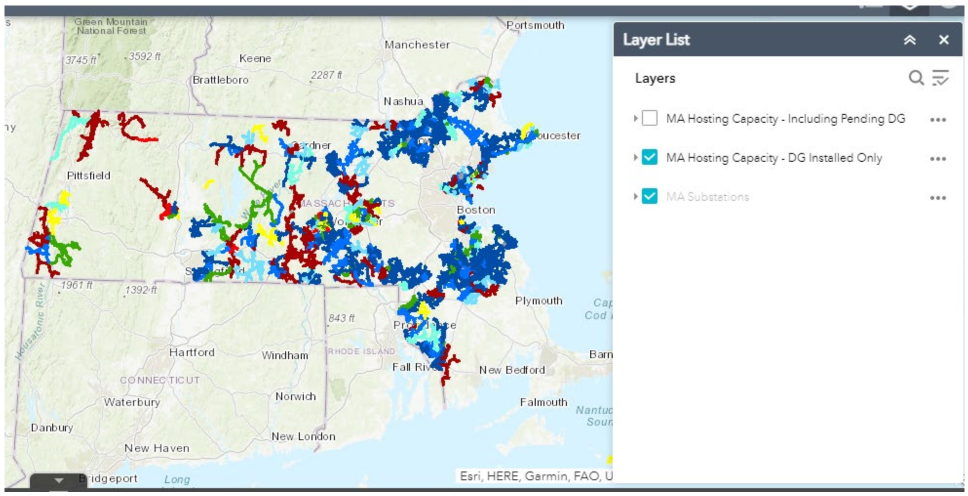
A typical area study takes six to nine months to complete with the main time components of modeling and analysis and stakeholder engagement. Including DER considerations in the area studies, which would increase modeling and stakeholder engagement time, could increase completion time to 12 months. This duration assumes that the software and data issues described above would have been addressed. If not addressed, the manual and labor-intensive data needs could drive even greater timelines. Overall, the Company would plan to conduct many studies in parallel, and with the learnings and transitional points discussed above, expects the plan for the Company's entire service territory (as prioritized by the annual assessment) would be completed in several years. After the first round of studies had been completed for the Company's entire service territory, the Company expects subsequent studies would be completed on a five-year cycle.

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 currently publishes hosting capacity maps that include hosting capacity available (MW) and show available capacity for new DG on the Company's distribution feeders and substations (based in N-1 capacity constraints). The hosting capacity maps are updated monthly, in accordance with D.P.U. 19-55-D at 7. The Company conducts a detailed hosting capacity calculation of the distribution feeders annually.

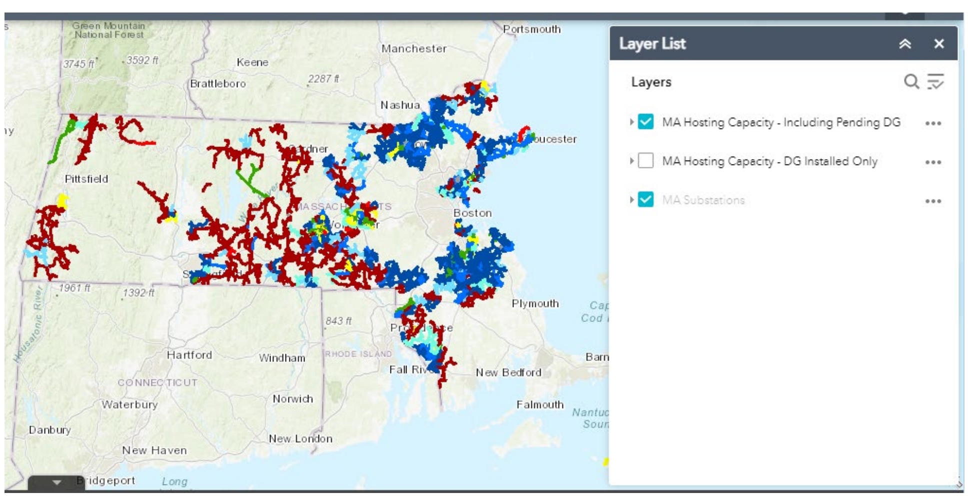
The Company has recently developed functionality that provides a limited view of future hosting capacity. Layers can be selected for "DG Installed Only" and "Including Pending DG."

The following figure shows the current hosting capacity map with the "DG Installed Only" layer on:



National Grid – Massachusetts System Data Portal
MA Hosting Capacity – DG Installed Only

This next figure shows the difference with the "Including Pending DG" layer on:



National Grid – Massachusetts System Data Portal
MA Hosting Capacity – Including Pending DG

As can be seen in the second figure, significant portions of central and western Massachusetts have turned red, indicating limited to no hosting capacity with the inclusion of in-queue DG.

A similar layer process could be used for planned projects, which would turn certain areas of the state green, showing available hosting capacity. National Grid cautions that this is a more complicated effort. The DG layering described above is accomplished by changing the DG input while the feeder topology remains unchanged. Incorporating the planned projects into the hosting capacity map would require changing the feeder topology. The feeder arrangement is currently imported from the Company's GIS system. This import would have to be changed for a planned project layer and a new geographical method developed.

With respect to the Department's question about the length of time required to update hosting capacity maps to reflect additional capacity built into the system after planned CIPs have been approved by the Department, the Company respectfully requests that the Department permit the EDCs to collaborate to propose 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 whether separate planned hosting capacity maps would be more feasible.[15]

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.

The Company also provided the following data to the Department on December 4, 2020 in response to the Department's request for early responses to this question from the EDCs.

15 "The Department endorses the goal of having effective hosting capacity maps that are comprehensive, up-to-date, and uniform across all Distribution Companies." D.PU. 19-55-D at 6.

Massachusetts Electric Company/Nantucket Electric Company

Calculation of Illustrative Annual Revenue Cap for Reconciling Charge

	Calendar Year	Estimated Revenue (a)	1.5% Cap (b)	Annual Revenue Cap (c)
(1)	2019	$3,302,551,090	1.5%	$49,538,266
(2)	2018	$3,374,415,893	1.5%	$50,616,238
(3)	2017	$3,069,403,915	1.5%	$46,041,059
(4)	2016	$2,904,804,333	1.5%	$43,572,065
(5)	2015	$3,135,178,215	1.5%	$47,027,673

(a) Per customer billing system. Includes applicable charges billed for distribution service, transmission service, transition charges, Energy Efficiency, Basic Service, and any and all related adjustment factors, as well as an adjustment for estimated commodity revenue for customers with competitive suppliers.

(b) Proposed bill impact cap

(c) Column (a) x Column (b)

(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.

Yes, a Common System Modification Fee is appropriate for Facilities using the simplified interconnection process for the reasons the Department identified: to offset the costs of System Modifications that simplified projects increasingly trigger; provide greater predictability to interconnection costs and timing; and to send a clear price signal that even small Facilities impose operation costs on the distribution system. Att. A at 10. The Company suggests that a Common System Modification Fee would most appropriately be used to cover the cost of minor System Modifications triggered by applications in the simplified process of the DG Interconnection Tariff.

In more detail, a Common System Modification Fee is appropriate for simplified applications served by a radial distribution feeder ("Small DG") to address the increasingly common situation in which a simplified application project triggers significant System Modification costs (relative to project cost) due to localized DG saturation. Simplified 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. As DG saturation increases in residential neighborhoods, an applicant that installs DG after their adjacent neighbor may be charged a few thousand dollars for a minor System Modification, which can equate to 10-20% of their overall installation cost. As National Grid discussed in its Small DG cost allocation proposal in D.P.U. 19-55, Small DG Facilities that are required to pay for these types of System Modifications are roughly twice as likely to cancel than those that require no System

Modifications, and this is a major cause of the overall application attrition rate for simplified Facilities in the Company's experience. Att. B-4 at 12. A Common System Modification Fee specific to the simplified interconnection process would reduce this barrier to interconnection of Small DG by providing more cost certainty and would provide the other benefits the Department identified in the Straw Proposal.

The Company proposes implementing a simplified Common System Modification Fee to cover minor System Modifications on or near a Small DG applicant's site up to and including service configuration and/or overhead transformer upgrades.[16] The Company proposes setting a minimum $/kW fee per application that would cover the cost of the applicant's minor System Modifications 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. The fee would be payable with the application. The amount of the fee could be adjusted annually based on actual spend.[17]

National Grid would estimate the number of simplified DG projects that were likely to require minor System Modifications based on historical trends in residential areas, and any changes to state solar incentive programs and/or market innovations.[18] Based on this estimate, the Company would submit an annual Small DG CIP budget to the Department for pre-approval.

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16 This proposal is similar to the Company's "Small DG" proposal in its D.P.U. 19-55 cost allocation proposal, with a somewhat different fee structure. Att. B-4 at 11-15.

17 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.

18 Since National Grid is proposing that the Company (and other EDCs) have an opportunity to update the fee as needed from year-to-year, the Company does not anticipate the need for major adjustments to the fee in any given year. However, as DG installation market trends (e.g., the size, types, and configurations of generation and storage – as well as the use of DG controllers and/or "smart" loads such as EV adoption) and economic drivers (e.g., state incentive programs, tax incentives, or other revenue sources that may be driven by DER resource aggregation in wholesale markets) shift over time, the Company proposes that these known changes (and/or changes anticipated as extremely likely in the following year) to interconnection patterns would be inputs to estimating the appropriate fee each year.

This budget proposal would include a total cost for all minor System Modifications required to interconnect all Small DG in the Company's service territory in the upcoming year and the proposed $/kW minimum fee for that year.[19]

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

The following are examples of upgrades the Company thinks should be funded by a Common System Modification Fee for Facilities using the simplified interconnection process (up to a fixed amount, with the applicant bearing any cost above that amount as discussed above):

- Overhead service transformer upgrades
- Secondary voltage system reconfiguration or service reconfiguration
- Service upgrades or new services that are required to enable the interconnection of the proposed Facility

The following are examples of upgrades the Company thinks should be specifically excluded from coverage by a simplified process Common System Modification Fee because of the cost and uncommon nature of these upgrades among simplified applicants:

- Line extensions beyond the number of poles allowed in the Company's line extension policies for traditional load customers
- Single-to-three phase conversions that would result in a change in the nature of the customer's existing service
- Any other scenarios where the cost of service equipment upgrades to serve the customer's property exceeds the fixed amount described above

[19] The Company suggests that "Small DG CIP Fee" might be preferable to "simplified Common System Modification Fee."

- Any costs for customers following the "Simplified on a Network" process[20]

The methodology described above, if paired with additional screening and process changes, would provide the flexibility needed to interconnect more DG applications within the simplified process that currently must interconnect under the Expedited process (despite initially applying under the simplified process) because they require minor System Modifications.[21]

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?

Such a fee would interact with the system planning process described in Section II as follows. The IDP studies that would be conducted under the Company's proposed DER Planning Process would take into account the aggregate impact of forecasted simplified applications on radial distribution feeders in determining capacity needs. The Company would develop an annual budget for the aggregate minor Common System Modification costs and the associated fee to be paid by Small DG applicants throughout its service territory, as discussed in more detail above, and would attribute the costs of that budget to the Reconciling Charge.

The Company would not include the forecasted capacity for simplified applications in the denominator of enabled MW capacity that would be used to set any CIP Fees in a zone (i.e., those charged to Expedited and Standard applicants). In other words, National Grid thinks fees collected

[20] National Grid notes that DG Facilities proposed on a network distribution circuit (regardless of DG Facility size) will almost certainly trigger major System Modifications (with relatively large System Modification costs) that are more akin to those required by Expedited or Standard applicants. Excluding these costs from the Small DG CIP Fee avoids a relatively small number of Simplified on a Network applicants inflating the costs for all simplified DG applicants.

[21] The EDCs have been working on a proposal (as discussed in the MA TSRG) to expand the eligibility criteria and streamline the screening process for simplified projects in anticipation of a Screening topic in D.P.U. 19-55, contemplated in the *Hearing Officer Memorandum Announcing Collaborative Process*, June 26, 2020, at 4.

from Facilities using the simplified interconnection process should not be used to offset the costs of CIPs approved through the proposed distribution system Planning Process. National Grid considers this approach more appropriate from a cost causation perspective since the vast majority of simplified applications are true "behind-the-meter" projects that are *both* DG and load customers, which is distinct from the vast majority of Expedited and Standard applicants. In this manner, applicants would only pay one fee associated with System Modifications, which would minimize the administrative burden for the EDCs and the Department, as well as avoid any simplified applicant confusion if they were required to understand and interpret the nuances presented by having two distinct DG cost allocation mechanisms.

Since simplified applications are typically connected within 12 months of application submission, the annual budget described above would not identify specific sites but would be available to all simplified applicants that paid the Small DG CIP Fee at the time of application.[22] Furthermore, since the application submissions ebb and flow month-to-month and season-to-season, National Grid recommends that any unspent Small DG CIP budget should continue to rollover year to year. For the first three full calendar years that the Small DG CIP program was in place, National Grid proposes that no funds should be diverted from the program budget for other purposes. However, starting in the fourth full calendar year that the program was in place, if the program budget rolled over from the previous year exceeded a Rollover Cap (for example, 150% of the annual average cost of the program over the previous three-year period), the EDC would propose, subject to the Department's approval, that any funds in excess of the Rollover Cap be

[22] Since applicants following the "Simplified on a Network" process would typically require System Modifications that are significantly different from those on a radial distribution feeder, National Grid proposes that these applicants would neither pay this fee nor receive any benefit from it (instead paying for any System Modification costs under the Cost Causation Principle).

used to offset the cost of future CIPs and/or the associated Reconciling Charge. However, National Grid does not anticipate significant overcollection of Small DG CIP Fees and would intend to adjust the $/kW rate as needed based on the Planning Process.

b. Expedited and Standard Facilities

i. Is a *minimum* Common System Modification Fee appropriate? If so,

1. Provide a proposed method for determining such a fee.

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.

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

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

ii. Is a *fixed* Common System Modification Fee appropriate? If so,

1. Provide a proposed method for determining such a fee.

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

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

iii. Explain how such a fee would interact with the distribution system planning process described in Section II.

1. As part of your explanation indicate whether a maximum price for Common System Modification Fees is appropriate.

2. If a maximum price is appropriate, explain how such a cap would be determined

iv. Should Common System Modification Fees be based on nameplate capacity and/or export capacity?

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

v. Since it is unlikely a Common System Modification Fee would cover all necessary upgrades:

1. Provide a proposed method for how to determine which upgrades would be covered by the funds collected.

2. Explain if such upgrades covered by the Common System Modification Fees would be subject to Department approval.

The Straw Proposal contains a series of questions in Section 2.b.i - v concerning the appropriateness of a minimum, maximum or fixed Common System Modification Fee for Expedited and Standard Facilities.[23] The Department has explained that it is specifically interested in exploring whether there are different fee structures that may better facilitate the timely construction of certain distribution system upgrades that benefit more than one interconnecting Facility or customers at large compared to the current structure and that any such additional fees must strike a balance between establishing clear price signals to drive efficient investment while providing reasonable certainty around interconnection costs. Att. A at 8-9.

National Grid agrees with the Department that the proposed CIP Fee coupled with the existing cost allocation structures, including the Cost Causation Principle and Group Study, is sufficient to address assignment and recovery of costs for the interconnection of DG and, similar

[23] The Company understands the Department's question to relate to a potential new Common System Modification Fee for Expedited and Standard Facilities and not to the existing Group Study Common System Modification fee in Section 3.4.1 of the DG Interconnection Tariff and has answered accordingly.

to the Department, endorses the CIP Fee over a Common System Modification Fee for Expedited and Standard Facilities. Att. A at 8.[24]

National Grid is opposed to a Common System Modification Fee for Expedited and Standard Facilities, whether such a fee is a minimum, maximum or fixed fee, because rather than establishing a clear price signal to drive efficient investment, it would mask the full extent of the costs triggered by planned and forecasted Expedited/Standard Facilities. Moreover, if such a fee were to be available in addition to a CIP Fee, it would distort the price signal that is one of the essential elements of a CIP Fee.[25] Finally, a maximum or fixed fee effectively would be a permanent subsidy because it would shift the costs that were not captured by the fee to all customers, an outcome that National Grid opposes.

With respect to facilitating the timely construction of certain distribution system upgrades that benefit more than one interconnecting Expedited or Standard Facility, efficiencies in the interconnection process will continue to be encouraged by providing the opportunity for Facilities to lower interconnection costs by seeking out portions of the distribution system which are most advantageous to interconnect DG. The EDCs developed, maintain and publish hosting capacity maps for this purpose.[26] The EDCs also are providing more detailed information about their distribution systems in pre-application reports, as required by D.P.U. 19-55-D, to aid potential applicants in their decision-making. As the Department has noted, with the hosting capacity maps

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[24] See, also, D.P.U. 20-75, *Hearing Officer Memorandum, November 4th Question and Answer Zoom Conference Call*, November 20, 2020, at 4.

[25] If the Department receives comments from other stakeholders in support of a minimum Common System Modification Fee for Expedited/Standard Facilities in addition to a CIP Fee, National Grid asks that the Department take into consideration the administrative burden that would be placed on the EDCs to administer such a program in parallel with the CIP Fee, which would necessarily include the burden of educating DG developers about the distinctions between the two programs and which program would be applicable to various types of System Modifications.

[26] Expedited/Standard applicants contribute to an efficient interconnection process by applying with sufficiently mature projects, which D.P.U. 19-55-D will facilitate.

and more expansive pre-application reports, DG applicants have substantial information available to assist with their DG interconnection investment decisions. D.P.U.19-55-D at 15.

In summary, establishing minimum, maximum or fixed Common System Modification Fees for Expedited and Standard Facilities would distort existing price signals and the price signal inherent in the proposed CIP Fee that are designed to facilitate the timely construction of distribution system upgrades by providing DG applicants with information to make decisions about where on the EPS it would be economical and otherwise advantageous to apply to interconnect their proposed Facility.

As National Grid is opposed to establishing Common System Modification Fees for Expedited and Standard Facilities, the Company is not responding to the other questions the Department raised except to say the Company would need to carefully consider how such a fee could be appropriately weighted with respect to nameplate capacity and/or export capacity if the Department were to adopt such an approach.

a. Requests to Distribution Companies

i. For each of the last ten years, provide estimates of the following:

1. The minimum, maximum, median, and average system modification cost for Facilities using the simplified interconnection process. Please also provide the total number and capacity of Facilities using the simplified interconnection process that have applied by year and the cumulative total system modification costs charged to Facilities in each year.

2. The minimum, maximum, median, and average system modification cost for Facilities using the expedited and standard interconnection processes. Please also provide the total number and capacity of Facilities using the expedited and standard interconnection process that have applied by year and the cumulative total system modification costs charged to Facilities in each year.

National Grid's data provided in response to these questions are set forth in Attachment 1. The Company also provided these data to the Department on December 4, 2020 in response to the Department's request for early responses to these questions from the EDCs.[27]

ii. To date, how much money have the Distribution Companies collected through the imposition of interconnection application fees, study costs, and interconnection related construction costs? Please organize this information by year going back to 2011 as well as by Facility type (i.e., Simplified, Expedited, Standard).

National Grid's data provided in response to this question are set forth in Attachment 2.

(3) Refer to Vote and Order, Section III, Proposals For Implementation in the Short Term. Please discuss the effectiveness of these proposals, specifically:

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?

The Company understands the Department's reference to the AGO's power control limiting "program" to be a reference to the AGO's proposal for the use of power control limiting (static curtailment) technology to avoid System Modifications. With respect to the Department's questions, it is important to recognize that power control limiting is a tool the EDCs already use. National Grid's perspective on the benefits of power control limiting is aligned in part with AGO's and differs in part. The Company agrees with AGO that power control limiting is an option that can enable an applicant to avoid larger System Modification costs through design changes but disagrees that this increases DG hosting capacity on a circuit. Att. B-1 at 5. Power control limiting could potentially allow a greater number of Facilities to interconnect, but the same overall MW

[27] In response to question a.i, the Company used less than or equal to 25 kW as a proxy for simplified projects in Attachment 1. For question a.ii, the Company responded with respect to application/Facility type, as requested, in Attachment 2. Study fees do not apply to simplified projects, and the Company does not have certain information in its database for Expedited and Standard applications, as shown by blanks in Attachment 2.

system limitations would apply. The Company also disagrees that power control limiting is a cost allocation method; rather, it enables the resizing of a proposed interconnecting Facility to optimize the economics for the Facility owner.

In response to the Department's question as to whether eligibility for power control limiting is only for new Interconnecting Customers, the answer is that this option is available to new National Grid applicants who have not yet finalized their project design. The Company offers DG applicants the opportunity to implement power control limitations if their initial design proposal exceeds a specific threshold that triggers the need for a System Modification that could be avoided by limiting the proposed Facility's real and/or reactive power export by altering the design to reduce the aggregate nameplate rating of their equipment and/or by introducing an adequate protection scheme that will limit the output of their equipment at the point of common coupling ("PCC"). Existing applicants may propose to modify their proposed project design to add an ESS or other design change to limit power export; however, if the design change is significant, the applicant may need to pay for a new study and potentially may need to withdraw their application and reapply with their new proposed Facility design.

National Grid does not consider power control limiting to be a method of cost allocation that allocates all costs to the direct beneficiary and avoids allocating costs to non-participants[28] because the applicant that exercises this option typically uses up the remaining hosting capacity of the EPS up to the identified MW threshold. Although the applicant thereby avoids the System Modification and the associated costs, the applicant's power control limiting does not increase the hosting capacity on the circuit in terms of the total amount of concurrent MW that the EPS can accommodate. System Modifications would still be required in order to increase MW hosting

[28] Att. B-1 at 16.

capacity of the circuit. Therefore, the next applicant in the queue would typically be required to pay for the System Modifications under the Cost Causation Principle without any opportunity to benefit from limiting their own power output.[29]

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.

For an applicant to effectively limit their power output to avoid the need for a System Modification, the applicant would either need to reduce the aggregate nameplate rating of their DG equipment and/or use one of the methods to control exports identified in the Department's proposed new Section 4.3 of the DG Interconnection Tariff, which the EDCs supported.[30] No equipment or software would need to be installed at the Company.

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

As noted above, the Company offers power control limiting today and no amendments or attachments to the ISA are necessary.

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.

Yes. Please see the response to (3)a.i.

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

The Company understands the Department's reference to the AGO's dynamic curtailment "program" to be a reference to AGO's straw proposal to develop a dynamic curtailment pilot in

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29 If dynamic curtailment were available, potentially the applicant could avail itself of that approach.

30 *Joint Distribution Company Comments Concerning Department Guidance On The Interconnection Of Energy Storage Systems*, April 28, 2020, Attachment A.

Massachusetts ("Program"). Att. B-1, Appendix C. The Company is aligned with AGO's proposal to investigate the use of dynamic curtailment in Massachusetts. The Company agrees that when 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. The Company does not consider dynamic curtailment to be a method of cost allocation.

Earlier this year, the Company began exploring whether, how and in what circumstances it might be able to use dynamic curtailment as a tool to facilitate the DG interconnection process. The Company's research and analysis to date, through what it calls its Active Resource Integration ("ARI") initiative, informs the Company's responses to the Department's questions.

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.

Based on the Company's understanding of the Program and subject to further investigation, the following is an overview of hardware and software likely required to be located at the Interconnecting Customer site to implement the Program:

- IEEE 1547-2018 listed Smart Inverters that have been verified to UL1741-SB to be able to perform the required commands.
- A secure communication gateway ("Gateway") that would allow the Interconnecting Customer Facilities to accept remote commands and respond with status updates. The Gateway would need to adhere to specific communication protocols and be built to specific cybersecurity requirements; the EDC might need to procure and own the Gateway device.
- The ability to physically secure and lock such devices.

- An EDC-installed PCC system recloser that would allow the EDC operator to isolate an unresponsive site from a remote location.
- Specific electric metering and data sharing Facility requirements with the EDC, such as sharing voltage and power measurements through Gateway.

Based on the Company's understanding of the Program and subject to further investigation, the following is an overview of hardware and software likely required to be located at an EDC's site to implement the Program:

- Advanced system monitoring and awareness, this is a combination of components the EDC would need to integrate to monitor the system.
- Advanced data analytics and decision-making software (collectively referred to as "Control Technology"), to properly identify which Interconnecting Customer Facilities were available for curtailment. The selected software system would need to be able to send a signal to a Facility that curtailment was needed. This Control Technology would need to be properly integrated with the EDC's distribution management system so the control center operators had visibility into the curtailment and the ability to override the system.
- Feeder and/or Substation monitoring at the point of the system constraint. This information on the constraint would be sent back to the control center.
- Two-way secure communication solution from an EDC's Control Technology to IEEE-1547 compliant smart inverters or central controller located at the Interconnecting Customer Facility. The secure communications would help protect all EDC communication and controls system that would be connected to the Control Technology. The EDC might also need to add security protocol and devices that

would isolate the EDC's control system from the Interconnecting Customer Facility to ensure only secure and reliable commands were communicated.

- Fail-Safe backup solution that would communicate with the Facility's PCC reclosers for an EDC's system operator to monitor and disconnect the Facility if it were to become unresponsive to the commands and/or during an emergency scenario where the Facility (even within pre-defined settings in the Control Technology) caused an unforeseen safety or reliability issue. This could be accomplished by opening the on-site reclosers and locking out the Facility until the issues were resolved.

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

Based on the Company's understanding of the Program and subject to further investigation, the ISA would need amendments and/or attachments to allow dynamic curtailment and to address at least the following:

- Technical and operational requirements
- Interconnecting Customer hardware requirements
- Communication protocol regarding curtailment (as well as a 24/7/365 point of contact if the Interconnecting Customer's communication protocol failed)
- Cyber security requirements
- Any additional contingencies and requirements that would only apply to participants in the Program, including requirements for Interconnecting Customers to respond if there were changes to the Program after the ISA was executed

The Company anticipates that an Interconnecting Customer participating in the Program also would need to enter into a curtailment contract with the EDC that, among other provisions, contained fees associated with participating in the Program and any financial penalties associated with violating the Program requirements; potentially these terms could be in the ISA instead.

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.

The Company currently does not have the ability to implement the Program. The two most significant technological challenges the Company likely would face in implementing the Program would be procuring the Control Technology and designing the two-way secure Gateway solution. Among other things, currently the Company does not have advanced system monitoring and awareness, although it is developing this capability under its Grid Modernization program.

The Company is investigating whether and how dynamic curtailment might be deployed through its ARI initiative, which, as noted above, is conceptually similar to the AGO's Program.

To date the Company has taken the following actions through its ARI initiative to investigate the potential value of dynamic curtailment:

- Peer Utility Engagement: The Company investigated similar projects pursued by SP Energy Networks (UK), Enedis (France) and Northern Powergrid (UK). The Company also met with Avangrid, who is currently pursuing a flexible interconnection pilot in New York State.
- Stakeholder Engagement: Beginning in April 2020, the Company engaged solar developers whose projects with the Company's upstate New York affiliate, Niagara Mohawk Power Company ("NMPC"), had been cancelled due to high

interconnection costs to solicit their input on the economic feasibility of dynamic curtailment. The Company has also hosted several sessions open to the New York solar developer community to collect input on program design.

- Expert Engagement: The Company has commissioned the Electric Power Research Institute ("EPRI") to perform an electric and economic feasibility assessment of its distribution system to be completed by mid-2022. This assessment will determine the constrained areas on the Company's distribution system that potentially would be best suited to this solution and also will analyze whether a dynamic curtailment paradigm would be an economically viable proposition for DG developers. The Company is also working with EPRI to develop a method for assessing location-specific hourly curtailment requirements. EPRI will investigate the viability and value of potential use cases for dynamic curtailment and generate selection criteria to optimize deployment if there is sufficient value. Based on the research it has done to date, the Company has identified potential use cases for dynamic curtailment, including circumstances in which dynamic curtailment might provide a more economical interconnection option, such as in areas of moderate DG saturation, and circumstances in which a Facility may need to be temporarily disconnected, for example, due to planned system maintenance or reconfigurations.
- Technology Investigation: The Company has engaged with several vendors to survey commercially available Control Technologies and their capabilities to specifically provide curtailment management solutions. These vendors provided information regarding previous commercial applications, technology capabilities, and IT and cybersecurity requirements for their product.

- Technology Demonstration: The Company plans to deploy an active, real-time dynamic curtailment demonstration pilot at two Company-owned solar sites in Massachusetts during 2021. The aim of the demonstration is to understand the operational requirements and determine the capabilities that would be required to actively control DG sites for reliability.

The next steps in the Company's ARI initiative to investigate the viability and utility of dynamic curtailment in its Massachusetts service territory are to initiate a local stakeholder engagement process, carry out the technology demonstration, determine the necessary commercial terms including fees and penalties, and identify the likely necessary amendments to the ISA to allow for dynamic curtailment and other tariff changes that might be required.

The final step the Company would need to take to successfully implement the Program, specifically, the Company's ARI program, would be to obtain the Department's approval to deploy such a program, including approval of ISA amendments and any other necessary tariff revisions and the terms of a dynamic curtailment contract.

As the benefits of dynamic curtailment would flow to certain Interconnecting Customers, the Company believes the Cost Causation Principle should apply and that participating Interconnecting Customers should be responsible for funding a dynamic curtailment program. If, based on its investigation into dynamic curtailment through its ARI initiative, the Company determines that dynamic curtailment would be a viable solution, in appropriate circumstances, the Company also would seek Department approval to levy an annual fee on participating Facilities as part of the dynamic curtailment contract. As part of its ongoing investigation, the Company is exploring how to appropriately size this fee to recover program costs and to provide an incentive that would allow the Company to share a portion of the value created by the program.

b. Provide details on the flexible capacity pilot in NY (applicable to National Grid only).

In its July 2020 electric rate case filing, NMPC requested funds to support an initial pilot program to demonstrate the ARI concept in New York. This pilot is designed to build upon the lessons learned in the preliminary technology demonstration to be performed on two Company-owned solar sites in Massachusetts described above. NMPC will test its ability to develop and manage flexible interconnections from several customer-owned renewable DG facilities on a single distribution circuit. This pilot, if approved, would test customer-facing features such as:

- Forecasted curtailment notifications to DG facility owners and NMPC's control center
- Automated measurement and verification processes to confirm participating DG are meeting obligations under their dynamic curtailment agreements
- Billing and settlement process for curtailment
- Consideration of enforcement schemes for violating terms of the interconnection agreement

In this pilot, NMPC will also seek to develop a standard, cybersecurity-approved monitoring and control package to integrate the utility SCADA network with customer-owned equipment at the DG site through a DG Gateway. The Gateway, as described above, will need to adhere to specific communication protocols and be built to specific cybersecurity requirements.

If the New York State Public Service Commission approves this project, NMPC hopes to interconnect pilot third-party owned DG sites by mid-2022.

c. **Request to the Distribution Companies**

i. **Based on the current DG interconnection queue, identify any potential Capital Investment Projects that could be constructed/installed in the near-term.**

<u>Potential CIPs</u>

Based on the Company's current DG interconnection queue, the Company has identified the following potential CIPs:

Barre Substation Expansion
Ware Substation Expansion
Stafford St Substation Installation
Wendell Depot Substation Expansion
North Oxford Substation Expansion
Little Rest Rd Substation Expansion
East Winchendon Substation Expansion
Lashaway Substation Expansion
Meadow St Substation Expansion
Treasure Valley Substation Expansion (see also IDP Pilot section below)
Uxbridge Substation Expansion

National Grid anticipates that there may be opportunities for the Company to propose one or more of the above as a CIP at the conclusion of the Group Studies that are pending in the area of the EPS that was studied in the central/western Massachusetts ASO transmission study and in distribution area studies. However, until the engineering analysis for these subsequent interconnection studies is more fully complete, National Grid will not be in a position to definitively identify whether the costs of System Modifications in any given area would be most appropriately allocated by the proposal of a CIP and associated CIP Fee or through the Group Study cost allocation process. In areas where a Group Study Common System Modification is identified that would enable incremental DG capacity above and beyond the capacity needs of the Group Study members (and would result in an economically viable CIP Fee), the Company anticipates that it would be prudent to propose such a Group Study Common System Modification as a CIP. In areas where a Group Study Common System Modification is identified that would only (or primarily) serve the in-queue participants of the Group Study, the Group Study cost allocation method may be most appropriate under the Cost Causation Principle.

Once the Company proposes a CIP from the list of potential CIPs identified above, and the Department pre-approves the CIP for cost recovery, the Company anticipates that it could begin the CIP in the near term. Any comment on timing beyond that would be speculative at this stage, before sufficient engineering analysis has been completed to propose a CIP.

IDP Pilot Project

The Company offers the following proposal for a pilot IDP project to investigate how IDP would work in practice in the Company's service territory, including with respect to identifying potential CIPs. National Grid thinks there is an opportunity to begin the transition to integrated area planning by leveraging recently completed analysis in a modestly sized electric footprint. The Town of Rutland, which is served by the Treasure Valley Substation that is identified above as a potential CIP, offers a unique situation that is aligned with many of the integrated planning concepts. Rutland is electrically isolated within National Grid's service territory, surrounded by municipal electric companies and adjacent to Unitil's service area. The town is served by a single substation with two feeders and the isolated nature presents unique contingency needs. The contingency needs are currently served by a dedicated medium voltage line from Worcester installed along a railroad right-of-way with asset condition issues. Rutland also has a robust level of DG activity. Last, the Treasure Valley Substation that serves Rutland is physically constrained and due to recently completed analysis, expansion is known to be costly. Regardless of the resulting recommended plan from such a study, there may be an opportunity to share the costs of the system upgrades that benefit both existing and forecasted load and DG customers, easing the economic burden on both customer classes.

National Grid sees an opportunity for this pilot to test IDP in the near term. As described above, the duration for the typically sized area study incorporating integrated planning is expected to take over a year. Because of the electric system size and known issues in Rutland, this pilot area study could be completed on a shorter timeline.

In addition to providing the fundamental study deliverables, this pilot would:

- Test the forecasting needs of the study. National Grid expects to gain a greater understanding of a timeline for both probabilistic forecasting and the practical application of multi-scenario probabilistic forecasts in planning.
- Test the data needs of the study. Specifically, what can be done with and without 8760-hour data for each technology input and what is a reasonable transition period to full 8760-hour analysis considering software evolution.
- Test the suitable range of scenarios to develop a comprehensive integrated plan.

This proposal is only for the study effort and does not presuppose the conclusions of the analysis. It is possible that a comprehensive integrated plan would determine construction was required only to meet the DG needs and would not enable incremental benefits to load customers, which would also be an important learning. However, should the study develop a cost-effective integrated plan, National Grid could continue the pilot (under a separate proposal) to test a variety of other concepts discussed in this document, including: identifying a potential CIP for Department review, DG community reception of the CIP Fee concept, and speed of incorporation into the Company's Massachusetts System Data Portal.

Transition Period

To facilitate the identification of CIPs for the Department's pre-approval and implementation of the proposed IDP pilot, further discussion and deliberation is necessary to define a clear path to grandfather and/or transition applications in the DG interconnection queue. If the transition is not clearly defined, National Grid is concerned that once the Department approves the CIP cost allocation methodology in the Straw Proposal or a similar methodology, in-flight projects may look to cancel, delay or resubmit their projects (while still expecting to retain previous study results) to gain more favorable terms under the new approach. Should that occur, the progress towards a more efficient interconnection queue accomplished through the Department's orders in D.P.U. 19-55 could be set back.

Once the Department approves the Straw Proposal in final form, the Company respectfully suggests that the Department allow the EDCs to develop an implementation plan in conjunction with stakeholders to ensure a smooth transition for pending applications in their respective DG interconnection queues.

IV. ADDITIONAL CONSIDERATIONS

No matter how well the process that emerges from this docket is designed and implemented, multiple external challenges outside the control of the EDCs will limit the realization of the full potential of such a process if the challenges are not addressed. First, long-term state targets for solar and other DERs (beyond the near-term Solar Massachusetts Renewable Target ("SMART") expansion) necessary to achieve state climate and clean energy goals have not yet been established. Second, land availability to site large solar arrays[31] is limited, both physically

[31] Land use for local onshore wind turbines also is highly restricted.

and by state and local permitting and zoning restrictions that constrain development.[32] Last, as the Governor of Massachusetts and other New England governors have advocated, meeting long-term state targets for solar and other DERs will require collaboration with ISO-NE to refine the regional wholesale electricity markets to better align with the clean energy mandates of the New England states.[33] These challenges and suggested solutions to begin overcoming them are described in more detail below.

A long-term solar deployment target articulated by policy makers would provide a uniform input to the long-term DER Planning Process envisioned in this proceeding.[34] The publicly available projections of the level of solar deployment needed to achieve the Commonwealth's 2050 goal vary widely. A recent Brattle Group analysis projected that with the electrification of heat and transportation needed to meet a 80% GHG reduction by 2050 goal for New England, between 2 and 5 GW of solar resources must be procured each year, a 10-to-25-fold increase compared to recent levels.[35] For New England, this would eventually result in approximately 140 TWh of production per year from approximately 107 GW of solar deployments. By comparison,

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[32] National Grid is exploring potential usage of public lands and an expedited permitting process to help address these challenges.

[33] *New England's Regional Wholesale Electricity Markets and Organizational Structures Must Evolve For 21st Century Clean Energy Future*. http://nescoe.com/resource-center/govstmt-reforms-oct2020/ See also, *New England States' Vision For A Clean, Affordable, And Reliable 21st Century Regional Electric Grid*. http://nescoe.com/

[34] The Commonwealth's economy wide 2050 goal is net zero GHG emissions, defined as: "A level of statewide greenhouse gas emissions that is equal in quantity to the amount of carbon dioxide or its equivalent that is removed from the atmosphere and stored annually by, or attributable to, the Commonwealth; provided, however, that in no event shall the level of emissions be greater than a level that is 85 percent below the 1990 level." *Determination of Statewide Emissions Limit by 2050*, Executive Office of Energy and Environmental Affairs, April 22, 2020, at 1. https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download
The Clean Energy and Climate Plan for 2030, which will set a 2030 goal, is scheduled to be published by year-end.

[35] *Achieving 80% GHG Reduction in New England by 2050*, The Brattle Group for the Coalition for Community Solar Access, Sept. 2019, at v and 20.
https://brattlefiles.blob.core.windows.net/files/17233_achieving_80_percent_ghg_reduction_in_new_england_by_20150_september_2019.pdf
Note that 80% GHG reduction by 2050 is a New England goal, not a Massachusetts specific 2050 goal.

ISO-NE's PV Forecast currently anticipates just 7.8 GW of cumulative solar capacity on the regional system by 2029.[36] The Commonwealth's Comprehensive Energy Plan published by the DOER in late 2018 projected only modest growth of solar by 2030 in New England under its "High Renewables" scenario, to approximately 10 TWh, representing about 7.7 GW of solar in the region, and was non-committal in regards to a goal for solar deployments beyond the projected SMART expansion, which is now in effect and doubled the SMART program to 3,200 MW of new solar generating capacity.[37] In summary, a long-term MW target (including intermediate targets) for the amount of solar the Commonwealth desires and will incent through SMART and other programs would provide valuable input for the long-term planning process.

National Grid has begun investigating the challenges around land availability to site large solar arrays and potential steps to address those challenges. The Commonwealth has two critical environmental priorities that require enhanced alignment: the protection of open space, habitat and viewsheds, collectively "landscape conservation," and the preservation of our climate through the expansion of renewable energy. Based on feedback from the developer community, rooftops and brownfield sites will not be enough to meet state clean energy goals.[38] This apparent disconnect between conservation and climate priorities results in a large amount of uncertainty for solar developers, a risk which invariably transfers to the EDCs. In National Grid's view, the resolution is rooted in the amount, and location, of solar desired by 2030 and beyond to meet clean energy and net zero emissions goals. First, as laid out above, the magnitude of solar that will best enable

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36 *Final 2020 PV Forecast,* Independent System Operator – New England, March 2020, at 9. https://www.iso-ne.com/static-assets/documents/2020/03/final_2020_pv_forecast_corrected.pdf

37 *Massachusetts Comprehensive Energy Plan: Commonwealth Regional Demand Analysis*, Massachusetts Department of Energy Resources, Dec. 12, 2018, p. 106, Figure 75. https://www.mass.gov/files/documents/2019/01/10/CEP%20Report-%20Final%2001102019.pdf

38 See, also, *Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future, Executive Summary*, E3 and EFI (Nov. 2020) at 6, citing New England's constrained geography and historical difficulty in siting new infrastructure as significant challenges for the region. https://energyfuturesinitiative.org/efi-reports

these goals in this timeframe needs to be determined and set out by policy makers, an essential feature that should be central to all future planning. The second larger goal is to develop "site-suitability criteria," and use these factors to identify the right type of land to accommodate solar. This starts by leveraging the entities responsible for the Commonwealth's strong environmental stewardship and empowering them to review the uses of all the underutilized lands in the non-private inventories of the Commonwealth, federal government or other public entities, that may best fit solar development without material impact on the public desire for landscape conservation. With these steps achieved, National Grid could better harmonize its current infrastructure plans with the Department's directive to plan its future infrastructure needs for DG interconnection (and subsequently for DER generally) in consideration of the Commonwealth's clean energy and climate policy objectives. Order at 6.

National Grid has been examining various blockers to supporting the achievement of the Commonwealth's targets for renewable energy and more specifically, the timely development of large solar arrays, and potential steps to address these blockers. Project permitting, including environmental permitting, siting approvals, and local authorizations, is a major bottleneck to constructing large solar array interconnections. Depending on the type of project and permits triggered, the permitting process can take two or more years. National Grid thinks that expediting permitting is critical to accelerated development of distributed generation and that there are ways to expedite permitting while still protecting environmental resources and public interests. To that end, the Company has identified a number of potential reforms to expedite permitting. The most impactful of these reform concepts is the creation of a "one-stop" consolidated permit process encompassing all state and local authorizations, which would address timing concerns and provide the certainty needed for the successful planning and implementation of the massive increase in renewable energy infrastructure needed to meet the Commonwealth's goals. This can be done without compromising the Commonwealth's commitment to environmental protection by using established, extensive best management practices and removing unnecessary duplication during the permitting process.[39]

Finally, a new level of integration and coordination with ISO-NE and regional transmission owners will be needed to enable similar changes on the bulk power system, including potential changes to cost allocation and capacity reservation policies currently in place. As mentioned, the New England governors have already called upon ISO-NE to review and update its approach to system planning to accommodate the clean energy goals the region as a whole is aiming to achieve. ISO-NE launched its Future Grid Initiative Project earlier this year, seeking to assess both reliability impacts of large-scale renewable generation additions, which will include significant solar resources, and new market pathways and mechanisms that may be possible at the regional level to provide long-term financial support through market mechanisms for those resources. In addition, ISO-NE and transmission owners will need to consider the mechanics of the Open Access Transmission Tariff ("OATT") and how capacity additions on the transmission systems are addressed. As explained in National Grid's comments in DPU 19-55 on this topic, transmission upgrades sought by the Company to accommodate future DG capacity deployments, to accompany distribution level infrastructure development, cannot currently be reserved for those future DG customers of the Company. Att. B-4 at 15. Transmission capacity, once built, is available on a

[39] Although National Grid is exploring this potential solution for any infrastructure project that is necessary for the growth of renewable energy, including generation; new, expanded, refurbished, replaced or upgraded transmission/distribution lines or substations; and interconnections of renewable energy generation to transmission/distribution facilities, for purposes of this docket the Company has described this potential solution to illustrate the level of involvement by public entities that is required to redress permitting challenges for large solar arrays.

first come first served open basis under the OATT. Modifications to this market structure will need to be considered to avoid a disconnect between state policy goals and regional system requirements.

VI. CONCLUSION

National Grid appreciates the opportunity to submit comments in response to the Department's request for comments on its Straw Proposal for a new DER planning process, methods for the assignment, and 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,

MASSACHUSETTS ELECTRIC COMPANY
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D.P.U. 20-75

National Grid

Attachment 1

Please See Excel Spreadsheet

Attachment 2

Amount collected from Simplified applications

Calendar Year	Application Fees	Study Fees	Construction CIAC*
2011	Not Applicable		
2012	Not Applicable		
2013	Not Applicable		
2014	Not Applicable		
2015	Not Applicable		
2016	Not Applicable		
2017	$28,140		
2018	$211,908		
2019	$207,804		
2020	$258,984		
Total	$706,836		

**National Grid processes applications requiring minor system modifications as expedited application*

Amount collected from Expedited applications

Calendar Year	Application Fees	Study Fees	Construction CIAC
2011	$92,677		
2012	$108,599		
2013	$79,283		
2014	$199,602	$15,000	$8,000
2015	$213,294	$15,000	$12,900
2016	$206,535	$28,900	$150,361
2017	$213,749	$12,240	$41,629
2018	$441,355	$22,700	$727,260
2019	$182,513	$87,174	$2,224,202
2020	$375,025	$113,100	$807,015
Total	$2,112,630	$294,114	$3,971,366

Amount collected from Standard applications

Calendar Year	Application Fees	Study Fees	Construction CIAC
2011	$641,843	$80,000	
2012	$479,255	$347,666	$2,910,822
2013	$388,530	$699,500	$20,344,347
2014	$1,132,350	$1,223,930	$23,942,258
2015	$1,397,137	$3,772,402	$28,825,296
2016	$844,775	$1,579,868	$33,180,834
2017	$1,856,943	$2,891,604	$20,595,429
2018	$2,618,388	$6,937,269	$81,245,346
2019	$396,902	$2,060,903	$50,311,860
2020	$622,710	$887,819	$37,547,592
Total	$10,378,832	$20,480,960	$298,903,785