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

THE NORTHEAST CLEAN ENERGY COUNCIL INC.'S COMMENTS ON THE DEPARTMENT'S STRAW PROPOSAL REGARDING DISTRIBUTED ENERGY RESOURCE PLANNING AND METHODS FOR THE ASSIGNMENT OF COSTS ASSOCIATED WITH DISTRIBUTED GENERATION INTERCONNECTION

Respectfully submitted,

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I. BACKGROUND

By order dated October 22, 2020, the Massachusetts Department of Public Utilities ("Department") initiated this proceeding to investigate (1) the electric distribution companies' ("EDCs") distributed energy resource ("DER") planning, and (2) the assignment and recovery of costs in connection with infrastructure modifications needed to interconnect distributed generation ("DG") to the EDCs' electric power system ("October 22, Order"). The October 22 Order includes a straw proposal ("Straw Proposal")[1] regarding (i) distributed energy resource planning,[2] and (ii) methods for the assignment and recovery of costs associated with DG interconnection that, according to the Department, was materially informed by cost allocation proposals submitted by stakeholders in D.P.U. 19-55,[3] including a proposal from the Northeast Clean Energy Council, Inc. ("NECEC"). *See*, NECEC Alternative Cost Allocation Proposal dated February 28, 2020 ("NECEC Cost Allocation Proposal"). In response to the Department's request for comments on the Straw Proposal (and in particular, to the specific questions contained therein), NECEC provides the following comments.[4]

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[1] Capitalized terms not otherwise defined herein shall have the meanings ascribed to them in the Straw Proposal.

[2] The Straw Proposal's working definition of a DER is "a resource that: (1) is directly connected to the distribution system, or indirectly connected to the distribution system behind a customer's meter; and (2) generates energy, stores energy, or controls load. Under this definition, distributed energy resources include distributed generation (e.g., solar panels), energy storage systems, electric vehicles, and controllable loads (e.g., heating, ventilation, and air conditioning systems and electric water heaters)." Straw Proposal, at 3 n.1.

[3] October 22 Order, at 6.

[4] In formulating the NECEC Cost Allocation Proposal, NECEC engaged Marc Montalvo and Daymark Energy Advisors ("Daymark") as its expert. Mr. Montalvo and Daymark also assisted NECEC in developing these comments.

II. INTRODUCTION AND EXECUTIVE SUMMARY

The Global Warming Solutions Act (St. 2008, c. 298, codified at M.G.L. c. 21N "GWSA") requires a reduction of greenhouse gas ("GHG") emissions in Massachusetts of 80 percent below 1990 levels by 2050.[5] In accordance with the GWSA and Governor Baker's commitment that the Commonwealth will achieve economy-wide "net-zero" emissions by 2050,[6] the Massachusetts Executive Office of Energy and Environmental Affairs ("EOEEA") set a legally binding statewide limit of net zero GHG emissions by 2050, defined as 85 percent below 1990 levels.[7] In identifying strategies to meet the 2050 GHG emission reduction mandates, EOEEA specifically states that a "pillar" of its Decarbonization Roadmap is clean energy expansion.[8,9]

There is no dispute that massive infrastructure improvements to the Commonwealth's electric transmission and distribution system will be required in order to effectuate the above-described legally-mandated decarbonization. It is also quite clear that these improvements cannot be undertaken solely by individual Interconnecting Customers; instead, the high cost of these upgrades requires robust cost-sharing and cost-socialization

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[5] The GWSA addresses the grave threats that climate change poses to the health, economy, and natural resources of the Commonwealth and is designed to make Massachusetts a leader in the efforts to reduce the GHG emissions that cause climate change. *New England Power Generators Assoc., Inc. v. Dep't of Environmental Protection*, 480 Mass. 398, 399 (2018).

[6] *See*, Governor Baker State of the Commonwealth Address, *available at* https://www.mass.gov/news/governor-baker-delivers-2020-state-of-the-commonwealth-address.

[7] *See*, Determination of Statewide Emissions Limit for 2020 (Apr. 22, 2020), *available at* https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download

[8] *See*, https://www.mass.gov/info-details/ma-decarbonization-roadmap.

[9] *See*, EOEEA, March 2020 Public Sessions Presentation, *available at* https://www.mass.gov/doc/march-public-meeting-slide-deck-for-2050-roadmap/download.

mechanisms to mobilize the financial resources needed to execute these projects and satisfy the GWSA. The legislative and executive policy commitments to achieve net-zero carbon emissions by 2050 are designed to benefit all citizens of the Commonwealth.[10] Thus, everyone who benefits from these infrastructure improvements should participate in funding those upgrades in a fair and equitable manner.

However, such costs are currently allocated in Massachusetts based on the principle that the DG facility triggering the need for the modification is responsible for all the costs of such modification ("Cost Causation Principle"). The NECEC Cost Allocation Proposal demonstrated that due to the numerous legislative and executive branch policy initiatives set forth above, the Cost Causation Principle is no longer applicable. All too often the Cost Causation Principle leads to an inequitable result in which a single beneficiary (the Interconnecting Customer) is required to pay the entire bill for the upgrade, notwithstanding the fact that numerous other parties will derive equal or greater benefits from the upgrade.

In its October 22 Order, the Department agreed that revising the existing cost allocation framework and instituting a long-term approach to distribution system planning are both needed to facilitate the integration of DER required to meet the Commonwealth's clean energy mandates.[11] With the Straw Proposal, the Department seeks to devise a cost

[10] Indeed, the Straw Proposal expressly states that the timely interconnection of DG in response to the Commonwealth's clean energy policy goals is expected to "benefit all ratepayers in the long run…" October 22 Order, at 6.

[11] See October 22 Order, at 4-5.

allocation structure that acknowledges and takes into account the impact the Commonwealth's clean energy mandates will have on the distribution system.[12]

NECEC commends the Department's efforts and supports many of the Straw Proposal's features. NECEC is in favor of creating zones for Capital Investment Projects ("CIP") supported by a rolling ten-year planning process. Additionally, NECEC supports requiring the EDCs to act as the initial funders for Capital Investment Projects within their service territories, thereby addressing the "first-mover" problem for Interconnecting Customers with DG projects in a CIP zone and allowing for Interconnecting Customer subscription over time. The EDCs are in the best position to accomplish this as they have well established cost recovery mechanisms and the administrative infrastructure to carry and allocate costs among ratepayers and Interconnecting Customers more efficiently than any individual Interconnecting Customer. If structured correctly, the approval and recovery mechanism will provide incentives to maximize the utility of the projects (i.e., maximizing the number of projects that interconnect) and minimize construction costs and timelines.

The Straw Proposal also sets forth a Common System Modification ("CSM") structure to address upgrades needed to interconnect DG projects in areas of common market-driven development that have not been identified through the EDCs' CIP planning processes. NECEC also supports this proposal, though notes that it will need to be fleshed out in more detail. Specifically, for the CSM structure to be effective, it must be closely

[12] October 22 Order, at 5 ("It is reasonable to expect that meeting this mandate will impact the distribution system, whether through accelerated deployment of DG and electric vehicles, increased load growth resulting from efforts to decarbonize other sectors, or in some other form.").

coordinated with the CIP planning process to ensure that the system is planned and built out in an efficient manner and, more importantly, that costs are controlled (including avoidance of stranded investments) and allocated to Interconnecting Customers only in proportion to the benefits realized.

Nevertheless, while the Straw Proposal addresses aspects of the mounting upgrade cost barrier to DG interconnection, it still places too heavy a cost burden for meeting the Commonwealth's clean energy mandates upon Interconnecting Customers. Simply put. the Straw Proposal does not reflect the full range of beneficiaries; nor does it recognize that Interconnecting Customers simply do not have the financial ability to fund 100% of these costs. Even if the costs are shared among them as currently contemplated by the Straw Proposal, the majority of DG projects will be rendered uneconomic. As a result, many otherwise net-beneficial DG projects will be precluded from being built, thereby preventing the Commonwealth from meeting its carbon reduction and clean energy mandate.

As detailed in the NECEC Cost Allocation Proposal and in the responses below, to ensure that the Commonwealth meets its climate and energy resiliency mandates, the Department should modify the existing cost allocation methodology such that Interconnecting Customers are allocated (i) no costs for upgrades to existing infrastructure that are considered multi-value investments;[13] and (ii) at most 30% of the costs for new

[13] A multi-value investment is one that is akin to National Grid's multi valued transmission projects ("MVT") set forth in the 2020 Transmission and Distribution Capital Investment Plan filed by National Grid in New York. See https://www.transmissionhub.com/wp-content/uploads/2020/04/NationalGridPlanMar312020.pdf. MVT projects are designed to address both National Grid system needs and State Transmission needs. This MVT approach takes a holistic view in designing solutions that incorporate existing system/asset capabilities and leverages National Grid's expertise to design efficient solutions to 69 and 115 kV issues. These projects will advance the

distribution infrastructure included as CIPs. In addition, the Department should ensure that the planning, approval, and implementation processes are expeditious and transparent so as to not delay the deployment of the renewable resources needed to meet the Commonwealth's GHG emissions reduction mandate.

III. NECEC RESPONSES TO QUESTIONS CONTAINED IN THE STRAW PROPOSAL[14]

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

NECEC Response:

The three solutions (items i-iii above) identified by the Department to address system needs are necessary, but not sufficient. NECEC recommends that the Department add the following categories of system (transmission and distribution) elements to its list of solutions: (a) circuit protection equipment, (b) reconductoring, (c) switching devices, (d) communications equipment, (e) upgrades/expansion of existing distribution substations, (f) grounding technologies, (g) capacitor banks, (h) technologies to

development of system upgrades and create additional system benefits by increasing transmission capability.

[14] Certain questions contained in the Straw Proposal (Questions (1)e, (2)a, (3) a iv, (3)b iii, and (3)c) are directed to the EDCs, and NECEC has therefore not provided answers to these questions.

accommodate reverse power flow and innovative technologies such as dynamic line rating technologies), and (j) non-wires alternatives. It is critical that DER system planning be largely technology neutral and sufficiently flexible and dynamic to allow for innovation. The Department should adopt a DER system planning process that is outcome-centered, i.e., focused on encouraging the deployment of the best engineered and most cost-effective packages of upgrades that meet the Commonwealth's policy goals.

The Department should take an expansive view of what might qualify as a CIP and prioritize and approve CIPs that accommodate aggressive renewable and clean DG development and interconnection, beneficial electrification, and grid modernization/resiliency, consistent with the Commonwealth's clean energy and climate mandates. Further, NECEC recommends that the Department adopt the following set of criteria for geographic or distribution system locations where EDCs propose projects:

- Whether the EDC has a high volume of DG applications currently or reasonably anticipates a significant increase in load over the next 5 years;
- Whether the EDC, informed by the Commonwealth and/or Interconnecting Customers, expects to receive a high volume of DG applications over the next 5 years;
- Whether the EDC expects significant electrification to occur over the next 5 years;
- Whether the location is otherwise of strategic interest to the Commonwealth's clean energy or climate targets as identified in the 2050 Roadmap Report and/or the Clean Energy & Climate Plan for 2030;
- Whether the location has untapped renewable capacity; and
- Whether reliability or asset driven upgrades to the transmission and distribution system are expected over the next 5-10 years.

For the CIP planning process to realize its full value, the EDCs must have an affirmative obligation to (i) identify projects that maximize the total benefits expected to be realized, and (ii) expedite the build-out (through transparent and aggressive timelines) to facilitate rapid interconnection to ensure that cost allocation does not come at the expense of interconnection timelines. The Department and the EDCs should establish a broad and transparent process to engage stakeholders in proposing, reviewing and approving cost recovery for such projects.

An example of such a broad and transparent stakeholder process is the one used by the Public Utility Commission of Texas and the Electric Reliability Council of Texas (ERCOT), with input from wind developers, transmission companies, and other stakeholders, to identify the Competitive Renewable Energy Zones (CREZ) in Texas.[15] The goal of the CREZ process was to identify transmission infrastructure that would facilitate the development and interconnection of a large amounts of wind generation; importantly, the transmission projects were not a response to existing interconnection requests or extant reliability issues.

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

<u>NECEC Response</u>:

The EDCs' system planning efforts should include local and regional transmission planning results and cost data. It is important that transmission be part of the comprehensive solution so that it does not become a barrier to the Commonwealth's

[15] *See*, Transmission and CREZ Fact Sheet, *available here* (https://poweringtexas.com/wp-content/uploads/2018/12/Transmission-and-CREZ-Fact-Sheet.pdf).

advancement of its clean energy policy objectives, including efficient DG deployment. As the increase in affected system operator studies has shown, the integration of DG is significantly impacting the region's transmission grid, and EDC coordination with transmission operators and ISO-NE to build to accommodate load growth happens today. Logically, as the EDCs plan their systems to address both DG and load growth, coordinating with the transmission operators and ISO-NE is essential to ensure that the transmission system is planned to support distribution level needs. That said, the proposed distribution planning efforts should not wait for the comprehensive joint transmission and distribution planning framework to be developed and implemented. The EDCs should immediately incorporate projections regarding beneficial electrification and DER deployment into their distribution system plans and, recognizing its jurisdictional constraints, the Department should require EDCs to account for known and anticipated local and bulk transmission planning activities.

Ultimately, the EDCs should plan and propose distribution and coordinated transmission upgrades based on comprehensive planning studies anticipating the need to expand their distribution system capability and to accommodate future load and DG interconnection customers. The EDCs should actively engage a process to ensure that transmission upgrades, including public policy upgrades, can be identified by ISO-NE, transmission owners, or even the EDCs themselves as part of a transmission system planning processes. These planned upgrades would be made not only in response to a request from an identified customer or set of customers, but also in anticipation of policy-driven distribution-connected DG deployment and other changes in customer demand such as electric vehicle charging, electrification of space-heating, and delivery of other services.[16] These upgrades may also relate to the EDC's Grid Modernization Plans.[17] When such upgrades are approved and implemented, because they have broad-based benefits (e.g., the entire New England system, multiple utilities, or a single utility), their costs would be appropriately allocated to the relevant set of beneficiaries.

The identification of distribution and transmission needs is only one step in ensuring there is adequate grid infrastructure to meet the demands of the Commonwealth's clean energy mandates. The engineering, permitting, and construction of grid upgrades can take upwards of five years; therefore, the Department should place strong emphasis and incentive on the timely construction of upgrades and the deployment of new technologies that can accelerate the reliable interconnection of DG facilities.

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.

[16] This approach is consistent with prior Department orders (e.g., Eversource performance-based rate making ("PBR") order in D.P.U. 17-05) that called for PBR-metrics tracking performance relating to rebuilding the distribution system to allow for reliable two-way power flows).

[17] Investments made by the EDCs related to Grid Modernization should be excluded from the CIP fee structure described below.

<u>NECEC Response</u>:

What benefits should be considered and how should these benefits be quantified?

The rapid deployment of DG has been largely in response to Massachusetts policy and incentives within the EDCs' distribution systems (both behind-the-meter ("BTM") and in front of the meter ("IFM"). The impacts on the distribution and transmission networks represent a sea change in the patterns of use and service demands on the grid. Moreover, it is broadly recognized that the proliferation of electric vehicles, heat pumps, and other distributed technology designed to reduce the GHG intensity of other sectors of the economy will also require significant additional investments in the electrical grid. Consequently, the benefits of network expansion do not accrue unambiguously to private DG interconnection customers (importantly much of the anticipated upgrade costs cannot be commercially justified based on expected returns). Rather, much of the expected expansion of the network must be made to enable the Commonwealth's clean energy policies, which are being pursued to benefit the citizens of the Commonwealth.

The assessment of distribution system upgrade benefits should therefore be informed by the Commonwealth's overall clean energy and climate goals (e.g., the EOEEA Decarbonization Roadmap and the forthcoming Clean Energy & Climate Plan for 2030) and assess: (a) performance improvements (e.g., reduced losses, unplanned outages, O&M costs), (b) quantity of incremental DG that can be cost-effectively interconnected, (c) changes in patterns of consumption due to beneficial electrification that can be accommodated, (d) the flexibility of the system and its ability to accommodate unanticipated future needs, (e) system resilience and ability to meet environmental challenges.[18] The planning process must ensure that the future needs of the grid are adequately captured for both large scale improvements to the networks and incremental upgrades to provide multi-value opportunities for the EDCs to invest in their networks and enable the grid that will meet the Commonwealth's decarbonization mandates.

In addition, the Department could look to regional transmission planning and cost allocation rules put in place to allow for the efficient development and integration of renewable resources remote from load centers. Common features of these planning and cost allocation processes adopted to facilitate implementation to ambitious clean energy goals are: (1) comprehensive plans, (2) clear cost allocation rules, (3) allocation of costs to broad set of beneficiaries, (4) broad stakeholder engagement, (5) clearly defined processes and timelines.[19] Based on the analysis in the Decarbonization Roadmap, the Commonwealth will experience increased electrification of transportation and building resources that could more double electricity demand. Accordingly, NECEC urges the Department to review this resource planning process with a broad lens in order to maximize the efficiency gains associated with a longer time horizon and the time and expense-saving benefits of this more integrated planning effort.

In addition, the Department should use the planning assessment to accelerate the investment timeline for system upgrades to reduce the length of the overall interconnection

[18] The *National Standard Practice Manual For Benefit-Cost Analysis of Distributed Energy Resources* provides a cost benefit evaluation framework that should inform the Department's decision in this proceeding. *Available here* (https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf).

[19] See, for example, the MISO Multi-Value Project process *available here* (https://www.misoenergy.org/planning/planning/multi-value-projects-mvps/#nt=%2Fmultivalueprojecttype%3AMVP%20Analysis%20Reports&t=10&p=0&s=FileName&sd=desc) and the Texas CREZ process.

process and accelerate cost certainty for individual DG facilities. By requiring the EDCs to anticipate and meet future system needs and reduce the time and costs of studying and modifying the transmission and distribution system, the Department has an opportunity to accommodate the level of DERs needed to achieve the Commonwealth's long-term clean energy mandates. This should be an iterative process that encompasses both the EDC planning perspective as well as stakeholder feedback.

To do this in a robust, equitable, and transparent manner, NECEC suggests the EDCs conduct a quarterly (or other regularly scheduled periodic) technical conference to share planning studies and outcomes and receive stakeholder input. The Department should consider a technical committee, made up of nominated leads from the Department, DOER, the Attorney General, the EDCs and affected system operators, the transportation sector, local government, commerce and the DER industry that can provide key input into the scenarios.

The appropriate method for cost assignment and recovery – costs should be allocated equitably among all beneficiaries

As articulated in the NECEC Cost Allocation Proposal, two principles should guide the approach: (1) costs for distribution upgrades that unambiguously serve only the entity requesting service (e.g., the Interconnecting Customer) should continue to be assigned solely to such customer, and (2) costs for distribution upgrades that may serve multiple beneficiaries should be shared among the Interconnecting Customer and all other beneficiaries. The reasoning behind these principles is straightforward. Principle one holds that upgrades that serve only one entity should be paid for by that entity. Upgrades that fall into this category include dedicated generator leads, metering and associated communication circuits, protective devices, etc. that have no perceivable beneficiary other than the Interconnecting Customer itself. Principle two holds that if an upgrade could benefit more than one customer by allowing, for example, new or expanded service for other load or generating customers, then the costs of the upgrade should be shared more widely in recognition of the distributed benefits. Upgrades that fall into this category include line reconductoring, substation upgrades, transformer replacements, etc. This cost-sharing approach is particularly appropriate in the context of long-term integrated planning to ensure the system is capable of hosting a broader set of expected (but not certain) future users.

The Straw Proposal is a step in the right direction, but fails to recognize non-DG beneficiaries and could lead to Interconnecting Customers paying for grid upgrades that benefit many other customers (and in some cases, have little or no relation to the DG facility in question), leaving Interconnecting Customers unfairly bearing the burden of funding a dramatically disproportionate amount of grid upgrades required by the Commonwealth. Under the Straw Proposal, load growth projects are eligible for special rate treatment, so the costs of these upgrades could be allocated to DG developers, risking an unfair inflation of the per kW CIP cost calculation in such instances.

NECEC agrees that the Department should approve CIPs that address load growth and DER interconnection, and, in many cases, existing reliability and asset condition needs. There is, however, an obligation to avoid burdening developers with inappropriate and unfair cost allocation treatment that exceeds the benefits received. Ultimately, if EDCs are upgrading parts of their transmission and distribution systems to address existing and future incremental load growth needs in the form of multi-value investments, these investments should be recovered through rates and not from Interconnecting Customers. To the extent new assets are required that benefit future DG interconnection and load growth, the costs that are ultimately allocated to Interconnecting Customers and load should reflect the respective benefits received.

Consequently, NECEC proposes that the cost allocation in the Straw Proposal be adjusted to ensure equitable and fair treatment for all stakeholders. The Department's cost assignment and recovery proposal fails to account for the value and immediate needs for otherwise deferred infrastructure investments required to support a clean economy. Accordingly, the Straw Proposal should be modified to allocate no cost to Interconnecting Customers for upgrades to existing infrastructure that are considered multi-value investments;[20] and at least 70% of the costs for new distribution infrastructure included as Capital Investment Projects should be allocated to ratepayers.

The NECEC Cost Allocation Proposal offered an implementable strategy that should be applied here. Specifically, CIPs in the distribution system that accommodate current and future DER interconnection needs should be allocated 70% to the EDC rate base, for allocation through EDC customer rates, and 30% pro-rata to Interconnecting Customers that are CIP subscribers. The 30% allocation to Interconnecting Customers should consider the total headroom enabled by the CIP and allocated as fixed $/kW fee for projects that require use of the CIP to interconnect and a Capital Investment Project Fee and CSM fee cumulative cap of $300/kW or $1.5 million per large DG interconnection.

[20] *See Supra*, at n.13.

The 70% - 30% split in the NECEC Cost Allocation Proposal for distribution projects is the most appropriate way to achieve this and follows the established FERC-approved ISO-NE Tariff model. NECEC Cost Allocation Proposal, at 16-19. Any unfunded amount will be recovered through the reconciling rate mechanism identified by the Department.

As discussed in the NECEC Cost Allocation Proposal, there are multiple stakeholders who benefit from increased transmission capacity for DG (e.g., owners of new DG facilities, owners of existing DG facilities, non-Interconnecting Customers and society at large through the achievement of the Commonwealth's public policy goals). As a result, the Department's cost allocation should reflect this diversity in beneficiaries. For local and bulk system transmission projects, 100% of the costs should be allocated to ratepayers.[21] This approach is broadly similar to the pool planned transmission facility construct historically used by NEPOOL to pay for the cost of bulk transmission upgrades that connected large regionally planned generators.

The Capital Investment Project Fee recovery period and the timing of Capital Investment Project Fee assessments on Interconnecting Customers should be considered. The lead time between Capital Investment Project Fee identification and Capital Investment Project Fee implementation will be a significant concern for Interconnecting Customers that are required to pay a Capital Investment Project Fee; therefore, the terms of Section 3.6.2 of the Standards for Interconnection of Distributed Generation will need

[21] The NECEC Cost Allocation Proposal allocated 70% of the costs for transmission upgrades to ratepayers and 30% to Interconnecting Customers. Upon further consideration of the nature and scope of transmission upgrades, in these comments, NECEC suggests that the most equitable approach is to allocate 100% of transmission upgrades to ratepayers while retaining the 70%-30% allocation framework for distribution upgrades.

to be adjusted. For projects that require a CIP for the purposes of interconnection, the Department should consider, with stakeholder input, a meaningful installment payment, with the Capital Investment Project Fee assessed when the EDC has commenced procurement for the CIP.

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.

NECEC Response:

There should be a cap on the dollar-per-kW billed to each facility that benefits from the CIP, which will result in a total dollar amount "ceiling" that an Interconnecting Customer is required to bear in the interconnection process. The NECEC Cost Allocation Proposal includes a cap for both large and small Interconnecting Customers (DG developers take on risk related to project development, including interconnection costs). Further, the EDCs are expanding and increasing group studies. The existing EDC DG interconnection tariffs impose penalties on Interconnecting Customers for attrition from group studies, which creates significant cost uncertainty among group study participants. A cap would bound the risk that the Interconnecting Customer is undertaking. Such caps should include all capital-related interconnection costs whether levied through CIP or CSMs discussed in later responses.[22]

[22] The Department requested the EDCs to provide the minimum, maximum, median, and average system modification costs for facilities using the simplified, expedited and standard interconnection processes. On December 4, 2020, National Grid responded by setting forth, in an Xcel spread sheet, the costs charged to specific projects. While a large amount of the projects are shown as "withdrawn" (evidencing the project attrition that occurs in no small part due to the application of the Cost Causation Principle), there are certain projects utilizing the expedited or standard process whose status is designated "Conditional Approval" that have been allocated system modification costs ranging from $2M to $19M. NECEC notes that there is no indication from National Grid's response that these "Conditional Approval" projects have moved ahead to construction and interconnection. Accordingly, the Department should not interpret this data as (i) showing

The CIP $/kw Fee should be capped to create a clear market signal to Interconnecting Customers that propose to interconnect in a CIP zone. Unbounded volatility in the Capital Investment Project Fee would significantly impact the confidence of Interconnecting Customers to develop in a CIP zone. The Capital Investment Project Fee should only include the costs associated with the capital installation (i.e., construction) of the asset. Any additional costs, such as O&M, should be recovered through rates as is currently the case for load and DER required infrastructure. NECEC agrees that Capital Investment Project Fees should not include administrative fees or facility-specific interconnection costs, but requests further clarity on the definition of facility specific costs.

NECEC appreciates the need to bound the annual charges that compose the proposed Reconciling Charge. (see Straw Proposal at 6-7). To ensure sufficient investment in CIPs, NECEC recommends the Department clarify that the 1.5% annual rate cap will only include CIPs in the distribution system and that no transmission costs or other costs contributing to an EDC's Revenue Requirement be included in the cap. Moreover, because of the dynamic nature of DG interconnection, the Department should periodically review and adjust the cap to ensure (i) that the Reconciling Charge is sufficient, and (ii) that adequate distribution upgrades are being made in a timely way to meet policy objectives.

price signals that will drive efficient investment, or (ii) an indication that Interconnecting Customers are able to solely bear such system modification costs.

Department Question:

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.

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

      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?

NECEC Response:

It is not necessary to treat simplified facilities in the same manner as standard/expedited facilities. As set forth in the NECEC Cost Allocation Proposal, there is value in having cost certainty and a mechanism for allocating the cost of upgrading shared service infrastructure among simplified facilities. Accordingly, for facilities using the simplified interconnection process, a properly designed and implemented CSM fee would be a significant improvement over the existing process. As applied to small systems (i.e., those with nameplate capacity below 60kW), the CSM process would fund Interconnecting Customer service infrastructure that serves more than one customer (e.g., shared service transformer and any service conductors identified within interconnection processes to be upgraded). To ensure predictability for Interconnecting Customers, a CSM fee for simplified facilities should be $20 per kW and capped at $500. While the CIP planning processes should study current and future needs of small system customers on their systems, as proposed, no CIP costs would be allocated to these customers while the CSM process would enable rapid consistent interconnection for all market-driven simplified project customers.

Department Questions:

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 establishing 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 cost 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.

NECEC Response:

The use of Group Study in Massachusetts may necessitate the need for a CSM process. Upgrades associated with a CSM can be multi-value in nature (e.g., upgrades of aged equipment, local load growth, and investments that support the resilience and electrification of the network). By definition, a CSM may not include equipment required solely to interconnect a single DER or a group of DERs, and may serve multiple current and future customers. For example, a CSM should not include system improvements that the EDC would otherwise need to make for reliability or asset condition needs within the 10-year planning period considered in the CIP process. An assessment against criteria must be performed to ensure that a CSM fee is an appropriate recovery mechanism for the cost of the infrastructure. If a project is not deemed a CIP for the purposes of rate recovery, the CSM fee assessed must be structured to ensure equitable cost allocation between proposed and future DG customers and system beneficiaries.

Rather than a minimum or fixed CSM fee structure, the CSM fee should be calculated as a pro-rata sharing of CSM costs, based on the rated capacity of the equipment, and the excess headroom capacity created by the CSM available to future DER customers.[23] NECEC proposes such a cost allocation approach because it preserves economic signals for development and provides cost predictability to Interconnecting Customers while reflecting the multiple beneficiaries of such projects. As with CIP distribution upgrades, each benefitting large Interconnecting Customer would pay a maximum of 30% of its allocated "Headroom Share," capped at $300/kW and not to exceed a Capital Investment Project Fee and CSM fee cumulative cap of $1,500,000 per Interconnecting Customer. The balance of costs (70%) would be allocated to the rate-base through the EDC's reconciling mechanism. The cost cap is integral to the funding and functioning of the CIP and CSM processes and would limit the sum of all shared upgrade costs allocated to Interconnecting Customer.

Facility-specific interconnection costs, CIP fees, and CSM fees are all drivers of a DG project's the economic viability. The first mover projects located in a potential CIP or CSM area will face a degree of uncertainty regarding the resulting fees and costs to interconnect and should therefore not be burdened with the entirety of upgrades that benefit later connected customers and beneficiaries. A CSM process that applies the same criteria as a CIP and results in a CSM fee (with a cap) creates a clear market signal for "first mover" projects regarding the viability to interconnect and for projects wishing to utilize remaining capacity.

[23] As previously described, the timing of CSM fee for Interconnection Customers should be considered and the terms of Section 3.4.1 and Section of 3.6.2 of the Standards for Interconnection of Distributed Generation will need to be adjusted. Much like the CIP Fee process described above, the Department may consider a meaningful installment payment, with the CSM fee payment to begin when the EDC has commenced procurement for the CIP.

NECEC offers the following case study describing an instance when a Capital Investment Project Fee and CSM Fee would both motivate infrastructure investment and unlock interconnection capability. In 2019-2020, National Grid completed a series of transmission and distribution studies to review the impact of 900 MW of DER seeking to interconnect in the Central/Western Massachusetts area. In June 2020, National Grid released the results of both the transmission study and sub-area distribution studies impacting these projects. The distribution sub-area studies reviewed the interconnection of 276 MW in 7 distinct areas, encompassing 20 substations, in Central/Western Massachusetts, with system modification costs amounting to $398 million. In October 2020, the results of the re-studies identified upgrades required for 130 MW, with system modification costs of $306M.

What is clearly demonstrated is that a pro-rata cost sharing of system modifications by project size is an inefficient mechanism, as the scope and scale of the upgrades are not sized appropriately, the benefits associated with grid modernization are lost; and costs are inequitably shared amongst the first movers. Even if projects withdraw, the same upgrades are needed when future projects arrive in the community. Industry and utility experience with the central/western cluster studies indicate the urgent need for (i) a forward-thinking approach to system planning, and (ii) a cost allocation approach that is inclusive of all system needs to allow projected load growth and electrification to occur and enable existing and future DER to interconnect. Without such an approach, electrification and renewable development will be prohibitive in every community in the Commonwealth, just as it has become in the Worcester and Franklin counties.

As described, a CSM may be identified outside of the CIP process due to a market driven need (i.e., as a result of a Group Study). These modifications should be viewed through the same lens as a CIP with a benefit-cost assessment to determine beneficiary impact and value. The CSM fee would be assessed in those instances where a project was not identified as a CIP during the ongoing planning process, and such CSM fees would be used to cover the costs of CSMs. As with NECEC's proposal regarding the planning process and the selection and funding of CIPs and CSMs, the allocation and funding of CSMs should be conducted in a transparent manner that maximizes value for current and future customers and for the expanded usage expanded and usage of the transmission and distribution network.

The EDCs should provide the Department with a regular accounting of facilities identified as CSMs, total CSM expenditures, and CSM fees collected. To ensure that costs of CSM facilities are being allocated correctly and recovered through the proper mechanism, the Department and stakeholders should be able to determine what facilities are CSM and how headroom created by new CSM facilities is being considered in CIP studies.

Department Questions:

2) 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?

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

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

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

i. Based on your understanding of the Program, identify equipment and software necessary for implementation of the Program and which equipment and software would be installed (a) at the Interconnecting Customer and (b) at the Distribution Company.

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

NECEC Response:

NECEC appreciates the Attorney General's proposal to mitigate interconnection costs in the short-term through a combination of power control limiting and dynamic curtailment. While each proposed strategy may resolve local interconnection issues based on the specific conditions facing individual projects, neither offers a broad solution that is commensurate to the interconnection challenges the Commonwealth currently faces. As a result, NECEC urges the Department to center its approach on the longer reaching, systemic change to cost allocation that has a larger beneficial impact discussed in these comments.

NECEC supports an interconnection process that allows an Interconnecting Customer to opt to limit its facility's export capacity or power output in order to reduce or eliminate interconnection costs or timelines. However, this must be a voluntary option for the Interconnecting Customer that is based on a transparent flow of information between the EDC and the Interconnecting Customer. In such event, the instances in which power controls or other means of modifying export capacity must be site specific with limited applicability. Moreover, neither approach addresses issues related to the necessary, forward looking approach that the Department contemplates in the Straw Proposal. Neither power control limiting nor dynamic curtailment alone will impact the CIP planning that is necessary for DG development to thrive in Massachusetts. As such, the Attorney General's power control program will not have a significant effect on resolving the interconnection challenges that the Department is tackling in D.P.U. 19-55 and D.P.U. 20-75. As the Attorney General's consultant recognizes, this is only a short-term solution.[24] And, even so, has limited applicability to those instances where marginal DG capacity will allow for costs savings by having an Interconnecting Customer elect to limit system capabilities. While NECEC supports both concepts because they will be helpful in limited and site-specific instances, it urges the Department to adopt a cost allocation and planning model that goes far beyond them and addresses the more systemic and far reaching challenges of DG interconnection and cost allocation.

NECEC also urges the Department to reject the Attorney General's recommendation to retain a "reimbursement approach" under which an Interconnecting Customer that triggers a system modification is responsible for paying the full costs, then bears responsibility for seeking reimbursements from subsequent developers who benefit.[25] As the Straw Proposal recognizes, the responsibility for up-front payment and reimbursement collection lies appropriately with the EDC. The EDC is in a position to view the full scope of development potential at a particular areas in its system. As a result,

[24] Strategen Consulting, DER Interconnection Cost Allocation Proposal, (prepared for the Attorney General's Office) February 28 ,2020 at 11.

[25] Strategen Consulting, DER Interconnection Cost Allocation Proposal, (prepared for the Attorney General's Office) February 28 ,2020 at 11-14.

it can make longer-term recommendations to the Department about cost-efficient infrastructure decisions that go beyond the needs of any individual project and can take future DG interconnection and other systems benefits into account. The EDCs have deep experience in collecting such reimbursements from developers and have established protocols for doing so. Moreover, since many Interconnecting Customers are unable to bear the high up-front costs of an upgrade, providing an Interconnecting Customer with an elusive promise of future reimbursement is unlikely to increase the chances that clean energy facilities will actually be constructed. Accordingly, the Department should reject the Attorney General's recommended "reimbursement approach."

Respectfully submitted,

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