COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Inquiry by the Department of Public Utilities on its own Motion into Distributed Generation Interconnection	)))))	D.P.U. 19-55

THE NORTHEAST CLEAN ENERGY COUNCIL INC.'S
ALTERNATIVE COST ALLOCATION PROPOSAL

Respectfully submitted,

NORTHEAST CLEAN ENERGY COUNCIL, INC.

By its Attorneys:

John A. DeTore
David C. Fixler
Greenberg Traurig, LLP
One International Place
Suite 2000
Boston, MA 02110
Tel: 617-310-6000

Dated: February 28, 2020

Table of Contents

I. INTRODUCTION

A. Background

Costs related to infrastructure modifications needed to interconnect a distributed generation ("DG") facility to the electric distribution system 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 Cost Causation Principle reflects a narrowly tailored "*but for*" test. Under this test, if, *but for* the requested interconnection, an upgrade to the network would not be initiated, then the requesting party must pay for all of the upgrade costs, irrespective of any other uses of the network. Thus, the cost of developing and upgrading infrastructure to interconnect DG that provides network benefits to an array of beneficiaries utilizing an improved resilient, reliable, and responsive network is financed exclusively by DG Customers.

As more particularly described below, while the Cost Causation Principle may historically have been a sensible approach when there was an unambiguous single beneficiary and the incremental uses of the network was relatively static,[1] it is no longer appropriate nor reflective of the dynamic nature of the electricity system because it is no longer aligned with the manners in which electricity is currently generated, distributed and consumed in Massachusetts. Specifically, Massachusetts is well into the dawn of a new

[1] Incremental uses of the network are relatively static when (i) the only generation additions to the system are large central generation facilities and there is predictable growth in demand for service on the network, and (ii) new users emerge from time to time to request service that requires an expansion beyond what would reasonably have been required to serve the demand growth of all other customers.

energy future that has been driven, in large part, by a number of legislative and executive branch policy initiatives designed to address climate change and foster the deployment of clean distributed resources. These policies, which are designed to benefit all in the Commonwealth, including ratepayers, contemplate the large-scale infusion of DG and additional sources of load such as EV chargers and heat pumps onto the electric grid that is occurring today.[2] In order to support such exponential amount of DG and new load, substantial upgrades to the transmission and distribution systems will be required. Such massive infrastructure improvements needed to achieve the Commonwealth's ambitious carbon reduction goals will require significant expenditures.

At the same time, the rapid deployment of DG onto the electric distribution companies'("EDC" or "EDCs") systems (both behind and in front of the meter) and the impacts on the distribution and transmission networks in response to these policy initiatives represents a sea change in the patterns of use and service demands on the grid. The proliferation of new and diverse requests for service[3] result in multiple beneficiaries from system upgrades (*e.g*., the interconnecting customer, previously connected DG facilities, society, other customers on the network and subsequent customers and DG facilities to interconnect) rather than an unambiguous single beneficiary (such as a large central

[2] In fact, both the Massachusetts State Senate and the Baker Administration have announced ambitious initiatives to achieve a net-zero carbon emission future by 2050 (*see*, for example, Senate Bill 2477, An Act Setting Next-Generation Climate Policy). *See, also* September 2019 Report by the Brattle Group – Achieving 80% GHG Reduction in New England by 2050. The Report can be found at this Link.

[3] For example, requests for new service to facilitate electric vehicle charging as well as increased service to serve new heating load, in addition to the growth in requests for distributed solar.

generation facility). Moreover, the incremental uses of the network are not static but changing rapidly.

As a result, the historically held Cost Causation Principle no longer straightforwardly applies, and all too often leads to an inequitable result in which one single beneficiary (the DG 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. Moreover, because DG facilities are orders of magnitude smaller than traditional generation plants and generate far less revenue, they simply do not have the financial ability to incur significant interconnection costs. Thus, application of the traditional Cost Causation Principle will inevitably prevent many DG Customers from proceeding with their facilities. This in turn will prevent the Commonwealth from meeting its statutory carbon reduction goals. In short, a new approach is needed to address this new grid and to ensure a more equitable allocation of costs and benefits to reach the Commonwealth's climate and energy resiliency goals.

B. NECEC Alternative Cost Allocation Proposal

At the October 3, 2019 technical conference in this docket, the Massachusetts Department of Public Utilities ("Department") announced that it would investigate alternatives to the Cost Causation Principle and initiated a process through which stakeholders could submit alternative cost allocation proposals. In coordination with stakeholders, this process has been refined through a subsequent technical conference,[4] a

[4] The technical conference took place on November 21, 2019.

stakeholder/Department conference call,[5] and the Department's December 26, 2019 Procedural Notice and Request for Public Comments ("Procedural Notice") requesting that stakeholders submit cost allocation proposals to the Department by February 28, 2020.

The Northeast Clean Energy Council, Inc. ("NECEC")[6] appreciates the opportunity to submit the alternative cost allocation proposal set forth in Section IV herein ("NECEC Proposal"). In contrast to the traditional Cost Causation Principle, the NECEC Proposal, developed with the expertise of Daymark Energy Advisors, [7] is aligned with the manner in which electricity is currently generated, distributed and consumed in Massachusetts. The NECEC Proposal relies on two principles that have supported the enormous progress our society has made in expanding access to electricity and constructing our current distribution and transmission grid. The first principle is that massive infrastructure improvements such as those that are necessary to achieve the Commonwealth's ambitious decarbonizations goals cannot be undertaken by individual customers; instead, the high cost of these upgrades requires robust cost-sharing and cost-socialization mechanisms to

---

[5] The conference call occurred on January 7, 2020.

[6] NECEC is a clean energy business, policy and innovation organization representing the business perspectives of investors and clean energy companies across every stage of development. NECEC's members are in the vanguard leading Massachusetts in the new energy future, as its members span the broad spectrum of the clean energy industry, including energy efficiency, demand response, wind, solar combined heat and power, energy storage, fuel cells and other advanced and smart technologies.

[7] In the Procedural Notice, the Department "highly encouraged" stakeholders to engage experts in formulating alternative cost allocation proposals; accordingly, NECEC engaged Marc Montalvo and Daymark Energy Advisors as its expert in this matter. Daymark Energy Advisors advises regulatory agencies, utilities, developers, large consumers, municipalities, financial institutions and investors on matters relating to energy infrastructure (including generation, transmission and distribution planning), regulation, and markets using an approach that integrates economic, financial, environmental, technical and societal perspectives. Daymark's interdisciplinary expertise and experience includes management consulting, economic planning, market analysis, procurement, financial analysis, and energy policy and regulation.

mobilize the financial resources needed to execute these projects. The second principle is that everyone who benefits from these types of improvements to the shared transmission and distribution grid should participate in funding those upgrades in a fair and equitable manner.

The NECEC Proposal expressly requires a DG Customer to fully fund upgrades that only benefit itself as such customer would under the Cost Causation Principle. Upgrades that fall into this category include, but are not limited to, dedicated generator leads, metering and associated communication circuits, protective devices, and other measures that have no beneficiary other than the DG Customer itself.

However, in the event an upgrade can facilitate new or expanded service for other load or generating customers, the NECEC Proposal eliminates one of the most significant barriers to the modernization of the Massachusetts electrical grid by alleviating the "first-mover" problem, wherein DG Customers are currently required to pay for the full cost of many upgrades that have a larger set of beneficiaries. Instead, in the event an upgrade results in shared benefits, the NECEC Proposal, following well established Federal Energy Regulatory Commission ("FERC") cost allocation principles, allocates the cost of such upgrade among (a) the DG Customer or customers whose facility or facilities that trigger the upgrade, and (b) the other beneficiaries of such upgrade, including the EDCs' ratepayers, in recognition of the distributed benefits. Upgrades that fall into this category include, but are not limited to, line reconductoring, substation upgrades, transformer replacements, and other similar such measures and facilities

Given the (i) sweeping policy and technological changes discussed above, and (ii) need to remove barriers to encourage the achievement of a net-zero carbon future by 2050, NECEC respectfully submits that it is time for the Department to move beyond the outdated Cost Causation Principle and acknowledge the broader set of entities that benefit from the interconnection of increased levels of clean DG and the upgraded infrastructure associated with such interconnection. Accordingly, NECEC respectfully requests the Department to adopt the NECEC Proposal -- a proposal that allocates the costs of such upgraded infrastructure through an equitable method that takes into account the multiple entities benefiting from the upgrade.

In the Sections below, NECEC describes in detail (a) the categories of upgrades for which costs need to be allocated, (b) the numerous beneficiaries of system upgrades with specific examples of how benefits might accrue to specific stakeholders, (c) the support (legal and otherwise) for NECEC's cost allocation approach, and (d) the full NECEC Proposal.

II. CATEGORIES OF SYSTEM UPGRADES

As detailed in the examples below, there are three broad categories of upgrades that could be required when a DG facility interconnects to the distribution system: (a) upgrades to the distribution systems that are owned and operated by the EDCs; (b) upgrades to accommodate shared service infrastructure[8] that is owned and operated by the EDCs; and (c) upgrades to the sub-transmission or transmission system. These distinctions are

[8] The term "shared service" refers to interconnection equipment and infrastructure that is used by multiple residential and small commercial customers (*e.g.*, single-phase transformers with a shared secondary). Generally, such shared service infrastructure only pertains to DG projects that are below 60kW.

relevant because the entities responsible for planning and upgrading the distribution and transmission systems are different, and the scope of the upgrade can vary.

The EDCs are responsible for the distribution system, and they fall fully under the regulatory jurisdiction of the Department. The entities seeking to interconnect to the distribution system, be they solar developers, storage developers, or otherwise, are customers of the EDCs ("Interconnection Customer"). Thus, the treatment of any costs incurred by the EDCs associated with interconnection-related distribution upgrades are determined by the Department.

The transmission owners ("TOs") and ISO New England, Inc. ("ISO-NE"), the regional transmission operator, are collectively responsible for the planning and operation of the transmission system. These activities are outlined in ISO-NE Tariffs and Transmission Operating Agreements and fall under the jurisdiction of FERC. ISO-NE and the TOs conduct regional and local planning to ensure that the transmission electric system is adequate to meet the reliability needs of all customers, including the EDCs. Currently, if transmission upgrades are identified to support a new DG Customer, that need is identified through the Affected System Operator ("ASO") process, whereby the EDC, as the transmission customer of TO, is typically assigned the cost of any transmission upgrades that are required to establish service for their state-jurisdictional customers. How these costs are allocated by the EDCs is determined by the Department and is the subject of this segment of D.P.U. 19-55.

A. Distribution Upgrades

Distribution upgrades resulting from the interconnection of DG or made in anticipation of DG interconnection fall into several categories:

- **Single facility |** The upgrade is made to accommodate the interconnection of a single facility.
- **Group of facilities |** The upgrade is made to accommodate the interconnection of a group of facilities. These upgrades may be determined through a group or cluster study.
- **Pre-emptive upgrades |** These are upgrades that an EDC makes based on planning studies anticipating a need to expand system capability to accommodate future load and interconnection customer needs. These upgrades are not made in response to a request from an identified customer or set of customers. This approach requires the EDC to plan for distribution-connected DG deployment and other changes in customer demand such as EV charging, electrification of space-heating, and other services to target broadly economic system investments. These upgrades may also relate to the EDC's Grid Modernization Plans.
- **Emerging mitigation strategies |** New technologies and operating schemes may present the EDC with strategies to reliably interconnect additional DG without making traditional distribution upgrades. These strategies have different cost-benefit profiles from traditional wires-based solutions and may include battery storage, D-STATCOM and D_SVC, flexible interconnection/active network management, and advanced controls or coordination of DG storage and advanced inverter settings.

B. Transmission Upgrades

Transmission upgrades resulting from the interconnection of DG or made in anticipation of DG interconnection fall into two general categories:

- **Directly assigned transmission upgrades:** The Interconnection of a single DG Customer, or group of DG Customers, could require an upgrade to the transmission system in the event an adverse impact is identified as a result of an ASO Study. The required transmission upgrades typically have broad reliability impacts and impact customers on both a local and a regional level.

- **Pre-emptive transmission upgrades:** Preemptive transmission upgrades, including Public Policy Upgrades, can be identified by ISO-NE, TOs, or even the EDCs themselves as part of a transmission system planning processes. When such upgrades are approved and implemented, they would presumably benefit the entire system, and their costs would be allocated to all New England customers, TO customers, or the EDC based on the regional or local benefits that the upgrades provide.

III. SYSTEM UPGRADES BENEFIT MULTIPLE PARTIES

The rapid deployment of DG 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")) and the impacts on the distribution and transmission networks represent a sea change in the patterns of use and service demands on the grid. Moreover, the proliferation of electric vehicles, heat pumps, and other distributed technology that is designed to reduce the greenhouse gas intensity of other sectors of the economy will soon require massive additional investments in the electrical grid. As new requests for service (e.g., interconnection requests, EV charging demands, BTM and IFM solar) proliferate, the Cost Causation Principle no longer (i) straightforwardly applies, and (ii) reflects the realities of meeting the Commonwealth's own policy goals. At present (and reasonably expected into the future) rather than an unambiguous single beneficiary associated with DG interconnection projects seeking to electrify, there are often multiple beneficiaries and categories of beneficiary. In such scenarios, the incremental uses of the network are not static, but in fact, change rapidly, and the Department's consideration of cost causation must adjust to address this new dynamic.

The array of beneficiaries from distribution and/or transmission upgrades made to facilitate an interconnection of any DG Customer include, but are not limited to:

- Owners of new interconnecting DG facilities.
- Owners of existing DG facilities.
- Society via the facilitation of public policy (*e.g.*, meeting the policy objectives of adding solar, thereby displacing fossil fuel-based generation and reducing greenhouse gas emissions) and through the fulfillment of public policy objectives (*e.g.*, reducing pollutants and improving grid resiliency through the addition of clean energy and energy storage).
- Customers on the network, including non-DG Customers such as residential, commercial, and industrial customers, as well as new load that will connect to the network in the future.
- Future DG Customers, including but not limited to, those in the interconnection queue.

As shown in the tables below, the impact on the potential beneficiaries is not dependent on whether the use case involves a single project or a group of projects but is the result of the shared benefits enjoyed by multiple users of common infrastructure.

[*REMAINDER OF PAGE INTENTIONALLY LEFT BLANK*]

Table 1: Impacts by Beneficiary

BENEFICIARY	IMPACT
Owners of new DG facilities (currently the sole cost bearer)	DG project(s) can participate and earn revenue for their owners in electric markets.
Owners of existing DG Facilities	Improved system performance from upgrades can reduce exposure to curtailment, thereby improving project economics and performance for existing DG facilities
Current and future customers on Network	Upgrades made to the system to interconnect DG will result in the creation or upgrading of infrastructure that can facilitate new or expanded service, for example, new and expanded services triggered by the electrification of space heating or electric vehicle charging. These services would otherwise trigger upgrades to the system that can be avoided or mitigated through the completion of upgrades triggered by DG Customers. Upgrades to aging infrastructure as a result of DG interconnections can improve system performance and reliability for all customers. The addition of DG to local circuits can defer, reduce the size of, or avoid additional investments to meet peak and non-peak needs, and can accommodate new loads with low or no additional investment. Storage installed downstream of congested transmission systems can be discharged to alleviate congestion and can provide a variety of other grid-supporting benefits to maintain frequency, address voltage variations, and serve as a blackstart resource for the grid, reducing the costs of providing these services through traditional means.
Future DG Customers	Upgrades may increase the DG hosting capacity of the network, thus increasing the opportunity for subsequent projects to interconnect.
Society at large	Upgrades to facilitate the interconnection of DG project(s) address public policy goals such as the Renewable Portfolio Standard ("RPS"), Clean Peak Standard, and Global Warming solutions Act ("GWSA"). These upgrades help to reduce emissions from the electric system, thereby providing health benefits and mitigating climate change. In addition, these upgrades can facilitate more rapid transportation and building electrification, thereby reducing the costs of meeting the Commonwealth's climate goals. Investment in new distribution and transmission infrastructure improves system performance, safety, and resilience, and expands opportunities for new economic development in upgraded areas.

Table 2: Impacts by Beneficiary Specific to <60kW (Shared Service Upgrade Case)

BENEFICIARY	IMPACT
Residential Shared Service Customer	Customer bill savings with possible participation in demand response programs.
Society	Interconnected customer(s) can help meet legislated public policy goals like RPS or GWSA. Reduced emissions create externality benefits like improved health and climate change mitigation. Upgrades may allow for more projects meeting policy objectives and providing externality benefits to interconnect.
Facilities already interconnected	To the extent that existing customer increases beneficial electrification, customer may benefit from existing shared service upgrade.
Customers on Network	Other customers on network could benefit from increased reliability or resilience in cases where the addition of DG improves the network's ability to weather storms. The upgraded shared service will improve power quality for connected customers.
Subsequent facilities to interconnect	The interconnecting project(s) will be using some portion of the hosting capacity on the shared service, this will reduce the opportunity for additional projects to interconnect in the future without upgrades. The required upgrades could increase the hosting capacity of the shared service beyond what is required for these projects. This would increase the opportunity for projects to interconnect.

Examples

To better understand the dynamics at play when a system upgrade is triggered, below are a series of examples demonstrating how benefits might accrue to different stakeholders and how hard it is to isolate a single beneficiary of any upgrade.

Example 1: Single Generator, Primary Network Upgrade Required

In this example, Generator X pays for upgrades to interconnect that increase the amount of power that can flow on the system, (*i.e.*, a circuit needs to be reconductored, a transformer is replaced with a larger size). The upgrades would not be initiated without Generator X's project, so under the Cost Causation Principle, Generator X is the cost-causer and therefore pays for the entire cost of the upgrade. Assume that the day after Generator X interconnects, Generator Y retires, freeing up capacity on the system, such that had Y retired before X interconnected the upgrades would not have been needed. Now there is excess capability on the network, all of which X has paid for, but none of which X requires. Under the Cost Causation Principle, any customer can use that capability without contributing to the cost of the upgrade that made it available. Thus, Generator X has created a system benefit that a future user can utilize at no cost. Both Generator X and the future user receive the exact same benefit; yet all of the costs are allocated to Generator X merely because it was the first user. Such a result is clearly inequitable; yet it is essentially mandated by the traditional Cost Causation Principle. The same kind of inequity would exist if a (industrial) load customer left and was replaced by EV charging load.

Example 2, Single Generator, Residential Shared Service

In this example, a residential solar customer on a shared service transformer pays for upgrades to interconnect that increases the amount of power that can flow on the circuit (i.e., a service transformer or service conductor). The upgrades would not be required without the proposed residential solar system, so under the Cost Causation Principle, the customer applicant is the first user and pays for the upgrade. Following the initial interconnection, the residential customer's neighbor connected to the same shared service transformer applies to interconnect a solar and battery system. Under the status quo Cost Causation Principle, any other grid user of any kind that comes along can now use the capability created by the upgrade without paying for any of the upgrade costs. Again, because the initial residential solar customer was the first user, it pays for all of the costs of the infrastructure upgrade while future customers pay nothing to enjoy the exact same benefits. Such an enrichment dynamic is currently envisioned for natural gas and electricity line extension policies, through a contribution in aid of construction ("CIAC")

Example 3, Large EV Charging Load Addition

A city decides to electrify its bus fleet and adds several level-3 EV chargers to its maintenance yard. The addition of this load requires upgrades to the distribution system. Because the upgrades are caused by load, the costs are allocated to customer rate classes using rate-making mechanisms in a distribution utility rate case. The upgrades increase the hosting capacity of the system and subsequently allows for additional generators to interconnect without cost.

Society is benefiting from the addition of the EV charging load as the electrification of transportation load will be a key to meeting the carbon reduction goals of the GWSA. Society is also benefiting in the event the interconnecting generators are renewable, and therefore contributing to state policy goals and substituting greenhouse gas emitting units.

Example 4, Single Generator, No Upgrade Required

In this example, Generator D connects and no upgrade required. However, Generator D uses the last available capacity on the circuit and the subsequent generator, Generator E, must pay for a potentially large upgrade to interconnect. Generator D and E are both similarly sized solar generators making similar contributions to meeting RPS and

Global Warming Solutions Act goals, but the Cost Causation Principle requires Generator E to pay substantially more to connect.

IV. NECEC'S ALTERNATIVE COST ALLOCATION PROPOSAL

A. NECEC's Proposal is Based on the Proposition that Beneficiaries Should Pay for Upgrades that Benefit Them

The above benefit analysis and beneficiary examples demonstrate that it is rare that an interconnecting DG Customer is the only party that benefits from upgrades to the distribution system. Instead, there are multiple parties that share the benefits of the upgrades. Thus, the application of the Cost Causation Principle typically results in an over-allocation of costs to DG Customers relative to their share of the benefits that result from the upgrades they initiate. For this reason, NECEC respectfully submits that instead of allocating costs for both distribution and transmission upgrades utilizing the Cost Causation Principle, the Department should utilize a cost allocation model that honors the proposition that beneficiaries should pay for upgrades that benefit them. Two principles should guide this new approach:

1. Costs for upgrades that unambiguously serve only the entity requesting service (*e.g.*, the DG Customer) should continue to be assigned solely to the customer.
2. Costs for upgrades that may serve multiple beneficiaries should be shared among the interconnecting DG Customer and other beneficiaries.

The reasoning behind these two simple 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 DG 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.

The following sections set forth the precedent that guides such new approach and detail how NECEC's proposed cost sharing model works.

B. <u>Precedent</u>

1. The "*But For*" Test Has Limited Utility Where There are Multiple Beneficiaries

The Cost Causation Principle utilizes a narrowly tailored "*but for*" test. Under this test, if, *but for* the requested interconnection, an upgrade to the network would not be initiated, then the requesting party must pay for all of the upgrade costs, irrespective of any other uses of the network. The fact that other parties are enjoying and benefiting from the upgrade as much or greater than the requesting party without having to pay for the upgrade demonstrates the "*but for*" test's significant limitation -- the test does not take into account that there may be multiple beneficiaries to an upgrade beyond the requesting party.

Such multiple party limitation has been recognized in other areas where a "*but for*" test is utilized. For example, the "*but for*" test is a hallmark of tort law and has been relied upon for years to determine factual causation in a negligence case. However, courts have recognized the difficulty the test poses in cases involving multiple potential causes. As a result, in cases involving multiple potential causes, the courts adjust to these facts and utilize a different approach that takes into account that there may be multiple causes. *See*, *e.g.*, *O'Connor v. Raymark Industries, Inc.*, 401 Mass. 586, 591 (1988) (factual causation in an asbestos case involving multiple potential causes not solely determined by "*but for*" test).

Similar to the courts in tort cases, the Department should look to a different allocation method where the facts limit the application of a "*but for*" test. As described below, the Department does not have to look too far, as the principles established by FERC governing cost allocation among TOs for transmission system upgrades can easily serve as a guide to a new cost allocation approach.

2. FERC Cost Allocation Principles

Prior to 1998, generators interconnecting to NEPOOL PTF were required to be "fully integrated" with the regional grid; that is to say they were required to demonstrate that their capacity could reach the aggregate load throughout New England under both normal and high-volume transfer situations and were required to pay for the upgrades to do so. In *Champion International Corporation and Bucksport Energy L.L.C. v. ISO New England, Inc., New England Power Pool and Central Maine Power Company*, 85 FERC ¶ 61,142 (1998), FERC ruled that a generator (Bucksport) could connect without having to pay for "full integration" system upgrades. In essence, FERC ruled that the complaining generator did not have to pay for system upgrades beyond what is necessary to reliably connect its capacity to the system. *See, Id*.

In its Order 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, FERC established the following principles governing cost allocation:

1. Costs must be allocated in a way that is roughly commensurate with benefits;

2. Involuntary allocation of costs to non-beneficiaries is prohibited;
3. If a benefit to cost threshold is established for determining which projects have net benefits, that threshold should not be higher than 1.25, absent sufficient justification;
4. The allocation of costs must be solely within transmission planning regions unless ratepayers outside the planning region voluntarily assume costs;
5. Transparency is required in determining benefits and identifying beneficiaries;
6. Different types of entities have the option to propose different cost allocation methods depending on whether the transmission project is associated with reliability, relieving congestion, or achieving public policy goals.[9]

Principles 1, 2, and 6 are particularly instructive and consistent with the principles underlying the NECEC Proposal -- recognizing the existence of multiple beneficiaries and the way the benefits of upgrades may accrue to grid customers depending on whether the upgrades are in response to reliability needs or public policy imperatives. Here, the changing demand for service and associated need for upgrades are largely in response to public policy imperatives, including clean energy mandates and greenhouse gas reduction goals.

Schedule 11, Section 5 of the ISO-NE Tariff provides that if a particular upgrade triggered by a generator "provides benefits to the system as a whole as well as to particular parties, then the cost of such Upgrade shall be allocated in the same way as Reliability Transmission Upgrades," which costs are allocated to all ISO-NE transmission customers.[10] Moreover, for transmission projects that are built to meet public policy needs,

---

[9] *See, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC ¶ 61,051 at 612-685 (2011).*

[10] *See, ISO New England, Inc.*, 95 FERC ¶ 61,384, at 24 (2001) (approving Schedule 11, Section 5).

by default, cost allocation for upgrades is per Schedule 12, Section 6 of the ISO-NE Tariff, which splits the costs between the entity requesting the project and all of the region as a whole as follows:

> *(a) Seventy percent of the costs of each Public Policy Transmission Upgrade shall be allocated to Transmission Customers taking service under this OATT in the same manner as Regional Benefit Upgrades. (b) The remaining thirty percent of the costs of each Public Policy Transmission Upgrade shall be allocated to the Regional Network Load of each state in direct proportion to the state's share of the public policy planning need that gives rise to the Public Policy Transmission Upgrade ("Planning Need").*

The *Bucksport* decision and the above cost allocation methodology recognize several important concepts: (1) the interconnecting facility should only be financially responsible for system upgrades necessary to connect its net export capacity to the system ("Headroom") and should not be required to pay for upgrades supporting the interconnection of incremental capacity above that Headroom; (2) upgrades to the network benefit multiple parties; (3) it is not practical to identify all of those parties explicitly because who they are changes through time; and (4) requiring the entity that requested the upgrades to pay something forces that entity to consider the alternatives and tends to produce better overall choices regarding the type and location of projects.

The ISO-NE Tariff allows for a structured process to occur to assess, identify, and implement a need to support a state sponsored public policy need, and the upgrade costs of a Public Policy Transmission Upgrade are recovered immediately in ISO New England regional rates. Accordingly, NECEC recommends that the Department authorize a rate recovery approach that follows a similar principle of 1) established criteria and

2) streamlined cost recovery. [11] The approach, described below, should be implemented on a go-forward basis and should not require a rate case to take effect.

C. NECEC Proposed Allocation Method

The NECEC Proposal allocates the costs of upgrades with multiple beneficiaries through a two-step process:

First, the incremental hosting capacity created by the upgrade would be allocated to each new, known interconnecting DG Customer proportionally based on the Customer's net export capacity.[12] This allocation represents the customer's "Headroom Share." For example, a customer that consumes 5 MW of a new upgrade that creates incremental hosting capacity of 20 MVA would be allocated a 25% "Headroom Share" of the upgrade. A single customer that triggers the need for an express feeder that benefits no other customers would be allocated a 100% "Headroom Share" of the costs of the feeder.

Second, the cost of the customer's "Headroom Share" would be further allocated between the DG Customer and other beneficiaries according to the rules below, which generally follow the approach adopted in the ISO-NE public policy allocation rules. The

---

[11] In the Department's 2018 Grid Modernization Order (D.P.U. 15-120; D.P.U 15-121; D.P.U. 15-122), the Department authorized $219 million in preauthorized statewide grid modernization capital investments that will allow the EDCs to upgrade their infrastructure to increase the use of renewable energy, electric vehicles, and energy storage. Notably, the Department approved $82 million in preauthorized spending for the 2018-2020 period associated with grid modernization investments with a dedicated cost recovery mechanism from ratepayers -- the Grid Modernization Factor ("GMF"). Thus, the Department has already recognized that ratepayers receive significant benefits from these infrastructure upgrades and should therefore be allocated a share of the costs of such upgrades. NECEC respectfully submits that the upgrades triggered by DG interconnection that result in shared benefits should not be treated any differently than the upgrades for which costs are recovered through the GMF since both modernize the EDCs' infrastructure and deliver significant customer benefits.

[12] Incremental hosting capacity created by new upgrades can be quantified through methods that are already available and in use at both the transmission and distribution level.

following cost allocation rules would apply to both distribution and transmission-level upgrades.

Table 3: Allocation Matrix

Type of Upgrade	DG Customer(s) Pays	Other Beneficiaries Pay
DG Customers that trigger upgrades that benefit only those customers or other new DG Customers and no other beneficiaries *Examples: Express Feeders, Metering.*	100% Costs for multiple DG Customers allocated pro rata by each customer's net export capacity	0%
Large DG Customers (>60kW) that trigger upgrades that benefit multiple beneficiaries *Examples: Substation transformer replacements, Distribution feeder reconductoring, distribution protection, transmission upgrades*	Each benefitting DG Customer pays a maximum of 30% of its allocated "Headroom Share," capped at $1,500,000 per DG Customer[13]	Non-participating beneficiaries (rate base) pay remaining costs.
Small DG Customers (< or = 60kW) that trigger upgrades that benefit multiple beneficiaries[14] *Example: shared service distribution protection or feeder upgrades*	Each benefitting small DG Customer pays a maximum of 30% of its allocated "Headroom Share" costs, capped at $500 per customer	Non-participating beneficiaries (rate base) pay remaining costs.

[13] In response to an Information Request from NECEC in the most recent National Grid rate case (D.P.U. 18-150), National Grid provided the actual interconnection costs for 58 DG facilities (anonymized) that requested a final accounting (reconciliation) between 2014 and 2018. The vast majority of such costs were well under $1.5 Million. *See*, Exhs. Information Request NECEC 1-16 and Attachment NECEC 1-16. While not entirely representative of the universe of previously incurred interconnection costs, the information provided in the response is sufficiently broad such that the Department should be comfortable that $1.5 Million is a more than reasonable cap amount.

[14] This approach has synergies with an approach recently proposed by National Grid Rhode Island for projects 25kW or smaller. See, [Small DG Cost-Sharing in RI]

To implement this approach, each EDC should be directed to determine, according to criteria established by the Department, whether an upgrade provides additional system benefits beyond those accruing to the DG Customer, such that it should be eligible for cost allocation. At minimum, these criteria should consider:

a. Existing and in-process distribution and transmission capital plans
b. Results of Area studies
c. Identification of existing or future beneficiaries based on:
    i. Existing load
    ii. Load growth
    iii. Power Factor contribution
    iv. Asset Condition / Refurbishment needs
    v. Grid Modernization and Electrification plans
    vi. Local Economic Development opportunities
    vii. Public policy needs
d. Identification of incremental capacity / Headroom made available for other beneficiaries

The EDCs should be directed to implement a one-year window during which costs will be allocated to subsequent DG Customers that pay for their impact study within one year of the triggering DG Customer's application approval. Such subsequent DG Customers are allocated costs according to the framework described above. After the closure of the one-year period, any remaining unallocated costs would be allocated to the rate base and recovered by the EDC.

The EDCs shall charge each DG Customer 25% of its allocated costs up front, with the balance billed as costs are actually incurred by the EDCs. This approach will better allow the DG Customer to manage its cash outlay while also creating the appropriate incentive for the EDC to complete remaining impact studies for other queued projects in a timely manner.

Illustrative Examples

A Transformer is upgraded from 20MW[15] to 40MW at a cost of $4.1 Million to accommodate Project A's 10MW project. This is determined to be a shared upgrade due to benefits to other existing and future customers.

Transformer creates 20MW of incremental capacity
(40MW - 20MW = 20MW)
Based on the cost allocation rule, each DG Customer will pay a maximum of 30% of its Headroom Share, capped at $1,500,000.

Project A seeks to interconnect 10MW

Project A uses 50% of shared incremental capacity (10 MW / 20 MW = 50%)
Project A Headroom Share Allocation: ($4.1M) * 50% = $2.05M
Project A Cost Allocation for shared facilities: 30% * $2.05M = $615,000
Project A Cap of $1.5M is not exceeded.
Project A also requires $200,000 of upgrades that are not shared (*e.g.*, metering and telemetry, generator tie line)
Project A total interconnection costs = $615,000 for shared facilities + $200,000 for individual facilities = $815,000

Project B seeks to interconnect an additional 5 MW

Project B will use 25% of shared incremental capacity (5 MW / 20 MW = 25%)
Project B Allocation: ($4.1M) * 25% = $1.025M
Project B Cost Allocation for shared facilities: 30% * $1.025M = $307,500
Project B Cap of $1.5M is not exceeded.
Project B also requires $150,000 of upgrades that are not shared (e.g., metering and telemetry, generator tie line)
Project C total interconnection costs = $307,500 for shared facilities + $150,000 for individual facilities = $457,500

[15] While the capability of AC transmission lines is generally presented as MVA, generation capacity is usually presented as MW. For consistency purposes, all references are presented herein as MW.

Project C seeks to interconnect an additional 5MW

> Project C will use 25% of shared incremental capacity (5 MW / 20 MW = 25%)
> Project C Allocation: ($4.1M) * 25% = $1.025M
> Project C Cost Allocation for shared facilities: 30% * $1.025M = $307,500
> *Project C Cap of $1.5M is not exceeded.*
> Project C also requires $200,000 of upgrades that are not shared (e.g., metering and telemetry, generator tie line)
> **Project C total interconnection costs = $307,500 for shared facilities + $200,000 for individual facilities = $507,500**

Beneficiaries' Share: $4,100,000 - $615,000 - $307,500 - $307,500 = $2,870,000

The NECEC Proposal applies only to upgrades triggered by DG facilities that do not have executed Interconnection Service Agreements ("ISA") with the EDCs. Since the ISA (i) sets forth and caps the universe of costs (including system upgrade costs) that a DG Customer must pay to the EDC to interconnect, and (ii) states that all costs in excess of the amounts agreed to in the ISA are borne solely by the EDC, any costs in excess of the cap, including the cost of upgrades to the transmission system that are identified by an ASO Study after the execution of an ISA are the sole responsibility of the EDCs.[16]

V. CONCLUSION

NECEC greatly appreciates the Department's willingness to examine alternatives to the traditional Cost Causation Principle. As described above, the Cost Causation Principle is no longer appropriate nor reflective of the dynamic nature of the electricity system because it is no longer aligned with the manners in which electricity is currently generated, distributed and consumed in Massachusetts. Simply put, there has been a sea

[16] NECEC respectfully suggests that the Department issue a guidance document in the near term confirming such EDC cost responsibility in the case of already executed ISAs.

change in the patterns of use and service demands on the electric system. As a result, the Cost Causation Principle leads to an inequitable result in which one single beneficiary (the DG Customer) is required to pay the entire cost of the upgrade, notwithstanding the fact that numerous other parties will derive equal or greater benefits from such upgrade.

Due to the high cost of such upgrades, application of the Cost Causation Principle will inevitably prevent many DG Customers from proceeding with their facilities, which in turn will prevent the Commonwealth from meeting its statutory carbon reduction goals. Accordingly, NECEC respectfully submits that a new cost allocation approach is needed to address the new nature of the electricity system and to ensure a more equitable allocation of costs that will allow the Commonwealth to reach its climate and energy resiliency goals. As described above, the NECEC Proposal does just that.

Because time is of the essence, NECEC respectfully requests that the Department adopt the NECEC Proposal in time for it to be utilized in allocating the costs of any upgrades resulting from the Eversource Level 3 ASO Study, and part 2 of the National Grid Western-Central ASO Study. NECEC understands that certain procedural steps must take place in order for the Department to adopt its proposal. NECEC recommends that the first such procedural step should be a technical conference that will allow NECEC to present and discuss its proposal in detail and answer questions from Department staff and other stakeholders.

Respectfully submitted,

NORTHEAST CLEAN ENERGY
COUNCIL, INC.

David C. Fixler

____

By its Attorneys:

John A. DeTore
David C. Fixler
Greenberg Traurig, LLP
One International Place
Suite 2000
Boston, MA 02110
Tel: 617-310-6000

Dated: February 28, 2020

ACTIVE 48819964v1