DER Interconnection Cost Allocation Proposal

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Report Details

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Introduction

Background

The Department of Public Utilities (the “Department”) has made cost allocation a distinct issue in *Distributed Generation Interconnection,* D.P.U. 19-55. Currently, costs related to infrastructure modifications needed to interconnect a distributed energy resource (“DER”) facility are allocated based on the principle that the DER facility causing the need for a modification must pay for that modification (“Cost Causation Principle”).[1] Based on stakeholder interest in an investigation into alternatives to the Cost Causation Principle, the Department commenced a process through which stakeholders may submit alternative cost allocation proposals for two customer groups: (1) small commercial and residential facilities; and (2) medium and large facilities.[2] The Department instructed stakeholders to either indicate support for the Cost Causation Principle or propose an alternative that can be implemented “in the near term with little to no further process.”[3]

Based on the guidance that alternative cost allocation mechanisms must be implementable in the near term, we have limited our near-term proposals to cost allocation mechanisms that have been implemented in other jurisdictions. By basing our proposals on existing mechanisms, we provide clear frameworks for implementation through the case studies included in the appendices. We have also provided recommendations as to how to apply these existing frameworks in Massachusetts. However, given the limited data available on the Massachusetts electric distribution companies’ (“EDCs”) system planning practices, including planning criteria and historical interconnection data, some proposals will require additional input from the utilities and stakeholders.[4]

Proposal Summary

This proposal suggests that the Cost Causation Principle, as it currently operates in the context of DER, does not equitably allocate distribution system modification costs resulting from DER interconnections in some instances and therefore proposes an alternate set of cost allocation mechanisms. It first identifies four guiding principles that inform our process for selecting alternative cost allocation methods: (1) beneficiary pays; (2) differentiation; (3) efficient greenhouse gas (“GHG”) reduction; and (4) transparency. Using these principles, we propose two separate cost allocation methodologies: one for residential and small commercial DER facilities and one for medium and larger facilities.

Our proposal continues exempting residential and small commercial DER facilities from system modification costs, while tracking any modification costs actually incurred by those facilities. For

[1] D.P.U. 19-55, *Hearing Officer Memorandum* at 3 (December 26, 2019). While the Massachusetts Standards for Interconnection of Distributed Generation currently focus on “distributed generation,” (“DG”) there is a need to consider a broader set of technologies, such as energy storage, hence our usage of DER throughout the document.
[2] *Id.*
[3] *Id.* at 4.
[4] It may be that distribution related data is available, but it is not centralized with a docket or other publicly available source.

larger DER facilities, we propose (1) a developer reimbursement mechanism; (2) continued support for the current cost allocation process proposed within the group study process;[5] (3) power control limiting; and (4) a dynamic curtailment pilot program for mitigating system modifications in the first place.

Evaluation of the Cost Causation Principle

This section explains our concerns with the Cost Causation Principle in the context of DER and why it is no longer a fair or reasonable framework for DER interconnection cost allocation in certain cases. It also highlights a related framework that was utilized at the Federal Energy Regulatory Commission ("FERC") regarding transmission cost allocation.

1. What is the Cost Causation Principle?

The Cost Causation Principle defines the way that DER interconnections in Massachusetts currently pay for system modification costs. Under the Cost Causation Principle, the DER facility that causes the need for an infrastructure modification must pay the cost of that modification.[6] Cost causation emerged within a power system made up of centralized generators interconnecting at the transmission level. It was also used in cost studies to classify and allocate costs to inform class revenue apportionments and rate design components.

2. Why, in some cases, is the Cost Causation Principle insufficient for renewable facility integration?

In the context of DER, the Cost Causation Principle was a reasonable method of allocating costs when interconnections were few and far between (*i.e.*, large central generators), and when the upgrade costs could be more easily absorbed by large projects. However, recent changes to the power system have impacted the equity implications of the Cost Causation Principle as it applies to the integration of renewables in the Commonwealth. State policies such as the SMART program have incentivized increased renewable energy installation at the distribution level.[7] The proliferation of distributed generation makes it less equitable to simply assign system upgrade costs to a unique facility that triggered a system constraint. This is because when multiple DER facilities are queued up to interconnect to the same constrained circuit, it is more difficult to justify charging only the marginal developer for an upgrade that other developers will derive value.

The FERC Order 1000, on transmission planning and cost allocation, similarly found that an evolving policy landscape can necessitate new cost allocation considerations.[8] The Commission

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[5] Currently under consideration in D.P.U. 17-164.
[6] D.P.U. 19-55, *Hearing Officer Memorandum* at 3.
[7] *See* 225 C.M.R. 20.00, *et seq.*
[8] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC Order 1000, Docket No. RM10-23-000, at 358 (July 21, 2011), *available at* https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf. ("the circumstances in which [the Commission] must fulfill its statutory responsibilities change with developments in the industry, such as changes with respect to the demands placed on the grid. For example, the expansion of regional power markets has led to a growing

also identified that the "risk of the free rider problems…is particularly high for projects that…may have multiple beneficiaries."[9] Not only does the Cost Causation Principle create inequity between DER developers through the free rider problem, but developers' attempts to avoid the free rider problem also inhibit the achievement of policy goals. Developers may delay their projects or defect out of the interconnection queue in hopes that another developer will pay the system modification cost instead. In Massachusetts, this delay can slow the progress of clean energy distributed generation, hinder state policy achievement,[10] and increase the administrative burden of queue management. FERC similarly acknowledged the consequence of slow facility investment.[11]

New technology is also creating cost allocation alternatives that were not previously available. For example, smart inverters enable solutions such as power control limiting, which allows a developer to increase the DER hosting capacity on a circuit without traditional equipment upgrades. In this instance, technology provides the developer an option to allocate a lesser cost *(e.g.*, reduced exports) to itself in order to avoid a larger system upgrade cost. We will discuss power control limiting later in the proposal.

Guiding Principles for Cost Allocation

The Department should use a principles-based approach to identify alternative cost allocation methods for DER interconnection. A principles-based approach allows decision-makers and stakeholders to align around cost allocation priorities and to ensure that the chosen solutions satisfy those priorities. The Department should follow three guiding cost allocation principles: (1) beneficiary pays; (2) differentiation; (3) efficient ("GHG") reduction; and (4) transparency.

The FERC also prescribed a principles-based approach in Order 1000, using its principles as criteria for demonstrating that a cost allocation method is fair and reasonable.[12] These principles will guide a more equitable allocation of distribution system upgrade costs. The principles-based approach also allows for the development of cost allocation methodologies that offer near-term solutions which could potentially be evolved to apply in the long term. Our proposed principles

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need for new transmission facilities that cross several utility, RTO, ISO or other regions. Similarly, the increasing adoption of state resource policies, such as renewable portfolio standards, has contributed to the rapid growth of renewable energy resources that are frequently remote from load centers.").

[9] FERC Order 1000, at 359.

[10] *E.g.*, Global Warming Solutions Act (St. 2008, c. 298); Act Relative to Solar Energy (St. 2016, c. 75); Renewable Portfolio Standard (G.L. c. 25A, § 11F; 225 C.M.R. 14.00, *et seq.*); Net Energy Metering (G.L. c. 164, §§ 138-140); Clean Energy Standard (310 C.M.R. 7.75); Clean Peak Standard (G.L. c. 25A, § 17(a); 225 C.M.R. 21.00, *et seq.*).

[11] FERC Order 1000, at 359. ("[A]ny individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development. The Commission explained that…a cost allocation method that relies exclusively on a participant funding approach without respect to other beneficiaries of a transmission facility, increases this incentive and, in turn, the likelihood that needed transmission facilities will not be constructed in a timely manner.")

[12] FERC Order 1000, at 435-436. ("The Commission requires each public utility transmission provider to show on compliance that its cost allocation method or methods…are just and reasonable and not unduly discriminatory or preferential by demonstrating that each method satisfies the six cost allocation principles…We adopt the use of cost allocation principles because we do not want to prescribe a uniform method of cost allocation … .")

are not mutually exclusive; rather there are multiple areas of overlap, allowing for the development cost allocation methodologies that satisfy multiple principles at once.

1. Beneficiary Pays

The "beneficiary pays" principle focuses on the idea that the cost of distribution upgrades must be allocated to those who benefit most directly from those upgrades, and not allocated to those who do not receive benefits. This proposal considers beneficiaries to be the direct participants in the interconnection process (*e.g.*, developers) and refers to participating stakeholders as "direct beneficiaries."[13]

The idea that system upgrade costs must follow their (direct) benefits represents an improvement upon Massachusetts' present Cost Causation Principle, which considers only the triggering cause of the upgrade costs without accounting for the rest of the upgrade's direct beneficiaries. Ensuring that all developers pay for the system upgrades from which they benefit yields a more equitable allocation of system costs. This approach also better aligns costs with the use of the system, ensuring that the costs represent value to the system. Finally, it helps avoid bottlenecks in interconnection by spreading costs more evenly among individual interconnection customers.

The beneficiary pays principle has been well-vetted as a guiding principle of infrastructure cost allocation. Two out of the FERC's six cost allocation principles in Order 1000 specify that direct beneficiaries must pay for system facilities. Cost Allocation Principle 1 instructs that the costs of transmission facilities must be allocated to those that benefit in a manner that is roughly commensurate with the benefits, while Cost Allocation Principle 2 instructs that those who do not benefit must not be involuntarily allocated the costs.[14] FERC ruled that these principles must be satisfied to yield a just and reasonable cost allocation method.[15] Given that developers do not solely utilize the system modifications they must pay for under the Cost Causation Principle, FERC's Order 1000 provides a helpful guide for redefining the cost allocation framework in MA.[16]

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[13] We recognize that all ratepayers benefit from renewable energy and an argument could be made that these costs should be socialized to all ratepayers. However, we find this issue to be outside of the scope of this proposal, as significant change to cost socialization is not a short-term issue. Additionally, the estimation of societal benefits brings up numerous data transparency issues that would not be appropriate to address in this proposal. For example, estimating the degree to which, or whether, energy storage reduces emissions would require a complex and lengthy analysis that would require much more time and data than is available in this proceeding.

[14] FERC Order 1000, at 447 and 455.

[15] *Id.*, n.6.

[16] The Regulatory Assistance Project ("RAP") has also touted the idea that costs should follow benefits. In its recently released cost allocation manual, RAP specifies that "costs follow benefits" is usually superior to the principle of cost causation. While the RAP manual covers cost allocation as it relates to utility revenue requirement and rate design, there are clear conceptual similarities between the applications, making RAP's determination relevant here. Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.)., *Electric Cost Allocation for a New Era: A Manual*, at 18 (January 2020), *available at* https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

At the transmission level, the beneficiary pays principle is used to allocate costs to jurisdictions that are far away from the system upgrade due to the networked nature of the transmission system. While the distribution system is not necessarily networked, the beneficiary pays principle should still apply. Using the beneficiary pays principle at the distribution system level acknowledges that ratepayers within the same EDCs are implicitly or explicitly paying for most interconnection costs through supply costs or state incentives. This fact demonstrates that while the distribution system may not be networked, the costs are shared by all EDC customers. Because costs are shared, a more equitable and efficient cost allocation principle will benefit all ratepayers.

2. Differentiation

The differentiation principle focuses on the idea that different grid conditions or DER facility specifications merit different cost allocation methodologies. It is important to avoid overly broad approaches that do not consider the nuance of allowing for different types of upgrades or even the non-upgrades that could be viable when DER facilities interconnect to the distribution system. Such a one-size-fits-all approach to cost allocation is not flexible, equitable, or efficient.[17] It excludes types of facilities that could have had a low impact on the distribution system if included under certain cost allocation methodologies, and could create a bias towards larger upgrades that primarily benefit the EDC at the expense of ratepayers or DER providers.

Tailoring cost allocation approaches to different scenarios can enable economic efficiency by opening pathways to new or unconventional methods of cost allocation. For example, developers could avoid system upgrades by utilizing curtailment to maximize developer and utility resources ultimately benefitting ratepayers.

Cost allocation methodologies that differentiate between types of system upgrades and their varying impacts on grid conditions balance the complexity of the interconnection standards with the accurate treatment of facilities that can have low grid impacts. For example, differentiating interconnecting facilities based on load characteristics can streamline interconnection processes and enable more low impact DER to interconnect. It is worth considering the variety of interconnection scenarios and identifying approaches that will properly address each.

The FERC also ruled on the importance of allowing for differentiated cost allocation methodologies. FERC Order 1000 permitted using “a different cost allocation method for different types of transmission facilities”[18] in recognition that different approaches could be appropriate for different types of transmission infrastructure. The Commission did not believe that differentiating between different facility types should cause any delay in process.[19]

3. Efficiently Achieving Greenhouse Gas Goals

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[17] FERC Order 1000, at 427. (“Almost all commenters urge the Commission not to adopt a “one-size-fits-all” approach to cost allocation and to retain regional and interregional flexibility.”).
[18] *Id.* at 484.
[19] *Id.* at 489.

This principle recognizes that GHG emissions have motivated several state policies and that the issue must be an important factor driving changes to the regulatory structure, including DER interconnection standards. Reducing GHG emissions is a long-term policy objective. There are numerous ways to alter cost allocation that could arguably help achieve GHG emission reductions. This proposal recommends alterations to cost allocation that can be implemented in the short-term and that make incremental progress toward more efficient GHG emissions. While more drastic methods could more directly address GHG emissions reductions,[20] the Department has determined that they are outside the scope of this proceeding.[21] Any efficiencies and cost reductions that lead to more DER development will meet this principle.

4. Transparency

The transparency principle focuses on the idea that more data is key to developing and verifying fair and reasonable cost allocation methods. While utilities in Massachusetts have been working to provide more information related to interconnection, such as hosting capacity maps and information related to the interconnection queue, additional information related to cost incurrence and tracking would be beneficial to all stakeholders. Specifically, more information related to utility distribution system planning processes would provide a more transparent baseline from which to evaluate costs caused by DER interconnections and the direct beneficiaries of system upgrades.

Transparency is an important compliment to the beneficiary pays principle. Since the beneficiary pays principle likely results in the sharing of system upgrade costs beyond the immediate cost causer, there is an increased need for detailed cost tracking for determining benefits and identifying beneficiaries related to a system upgrade.[22] Take a DER system upgrade, for example, that consists of a large set of distribution equipment, including a substation transformer. Under the cost causation principle, the entire cost of the system upgrade would be allocated to a single interconnecting facility. Under the beneficiary pays principle, however, the substation transformer could be found to provide benefits to other interconnecting facilities and, therefore, this cost could be allocated to other interconnecting facilities that are direct beneficiaries of the system upgrade. Given the increased complexity of determining the benefits of a system upgrade and the associated beneficiaries, the granularity of data and baseline distribution planning assumptions will be more important.

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[20] For example, under National Grid's Reforming the Energy Vision ("REV") Pilot in New York, the utility proactively conducts network upgrades, which future interconnecting projects must pay back when they utilize the upgraded capacity. *See* Appendix A, Case Study 4 for more detail.
[21] D.P.U. 19-55, *Hearing Officer Memorandum* at 4 ("…while the Department recognizes that many stakeholders seek a long-term solution for preemptive infrastructure modifications to meet state climate change requirements, this is not the appropriate forum for such a proposal.").
[22] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.)., *supra* note 16, at 140.

Proposal #1: Residential and Small Commercial DER Facilities

Socialize system modification costs

The proposal for cost allocation for residential and small commercial DER facilities outlined below maintains and builds upon the status quo in Massachusetts. Residential and small commercial DER facilities have not historically had to pay for infrastructure modifications associated with their interconnection and this proposal does not change this arrangement in the short term. However, we do propose to track the resulting system modification costs.

1. Exempt residential and small commercial facilities through the simplified process

Under the Standards for Interconnection of Distributed Generation ("DG Interconnection Tariff"), the simplified process applies to "certain inverter-based facilities of limited scale and minimal apparent grid impact."[23] Under the simplified process, projects avoid several of the technical reviews and studies associated with the expedited and standard processes. Currently, these projects may incur and pay for minor system modifications "in certain rare circumstances."[24] We propose that the requirements for system modification cost allocation in the DG Interconnection Tariff for residential and small commercial facilities be more specific. The DG Interconnection Tariff should make clear that significant system modification costs should not be allocated to these facilities, only local distribution facilities directly triggered by interconnection. This change is reasonable in recognition of the low probability that smaller systems will directly trigger larger system modifications and to reduce administrative burden.[25] Including a provision in the DG Interconnection Tariff specifically exempting facilities that qualify for the simplified process from paying for system modification costs would clarify and streamline the tariff.

2. Track system modification costs from residential and small commercial facilities

Given state policy goals and consumer demand, an increasing penetration of small DER facilities may occasionally necessitate more significant distribution system upgrades. Over time, regulators may need to revisit the cost allocation approach for small facilities based on the magnitude and frequency of these potential upgrades.

We therefore propose that in order to better understand the impact of small DER facilities on electric system costs, the Department should require Massachusetts utilities to record and report data on any residential and small commercial facilities that trigger network upgrades beyond local system upgrades. This additional data is important for two reasons. First, a threshold is needed to decipher between "local system" and "system-wide" equipment upgrades to better define what system-wide upgrades are under these circumstances. Second, the type

[23] *National Grid Standards for Interconnection of Distributed Generation*, M.D.P.U. No. 1320, at 8 (Effective October 1, 2016).
[24] *Id.* at 13, 15.
[25] To the extent that simplified facilities go beyond residential and small commercial installations, our proposal should be evaluated for applicability to the other facilities.

and significance of the system-wide upgrades need to be tracked to determine how frequently they occur and their significance. Without additional information and specificity around the cost information noted, the impact of an alternative cost allocation will be unknown. To ensure that ratepayers are not incurring excessive system upgrades costs, steps should be taken to begin categorizing and tracking cost data for when numerous small DER interconnections trigger substantial system upgrades.

To minimize administrative burden, parameters should be established for cost tracking purposes. Some possible parameters could include: (1) a threshold point for determining what are considered local system upgrades; (2) a minimum system upgrade amount that triggers tracking; and (3) proper identification of investments that are incremental to status quo distribution system plans. A stakeholder process would likely be required to ensure that comprehensive and useful information is tracked.

Proposal #2: Medium and Large DER Facilities

Our cost allocation proposal for medium and large DER facilities combines several mechanisms that align with our guiding principles of beneficiary pays, differentiation, transparency, and efficient GHG reduction. Our principles-based approach recognizes that there is a need to both mitigate system modifications and appropriately allocate those system modification costs when they cannot be avoided.

High circuit saturation of DER does not have to result in expensive upgrades, delayed interconnection queues, and defecting developers. Under arrangements that control and manage power export, viable projects can interconnect without causing costly and time-consuming upgrades. By allocating the cost of power curtailments to a direct beneficiary, more equitable and timely cost allocation can be achieved. We describe two complementary such approaches below: (1) power control limiting; and (2) a dynamic curtailment pilot program.

In addition to mitigating upgrades, there are also ways to allocate unavoidable system modification costs that can reduce developer risk and cost burden. When developers must pay only for the portion of the upgrade that they will utilize – rather than an entire upgrade that can serve several other facilities – this more equitable division of costs can enable more facilities to interconnect, clear the project queue for others, and minimize administrative study time and cost. This proposal combines complementary cost allocation approaches: developer reimbursement and group study.

We selected these mitigation and allocation approaches with particular attention to their short-term applicability. Per the Department's directives, [26] these mechanisms could be implementable in the near term. While it is important to implement short-term solutions, cost allocation mechanisms will also need to adapt over time as technology, data, policy, and regulatory frameworks evolve.[27] The following proposals not only meet the Department's call for immediate solutions, but they also build a working foundation for the future evolution of cost allocation policy for DER interconnection.

1. Reimbursement from subsequent developers

Under the reimbursement cost allocation approach, the individual developer that triggers the system upgrade pays the full cost upfront and future projects then pay the original developer back in part when they utilize the upgraded capacity. This approach is a highly feasible short-term option because it can be implemented quickly without dramatically changing the current paradigm.

The reimbursement approach focuses on sharing the significant costs associated with upgrades to distribution system equipment that ultimately benefits numerous interconnecting DER facilities.

[26] D.P.U. 19-55, *Hearing Officer Memorandum* at 4.

[27] For example, data related to distribution system planning processes and methodologies would be useful. This data could aid in the development of more granular cost allocation approaches could be considered, such as determining incremental costs caused by DERs, as opposed to assuming all, or a large portion, of the system upgrade is interconnection related.

When DER facilities trigger upgrades, the utility must modify the system to maintain reliability and ensure safety. Additionally, the utility must use readily available and economical distribution equipment (*i.e.,* customized equipment is not used for a typical upgrade). For these reasons, system upgrades tend to be "lumpy" – *i.e.*, most distribution system equipment is manufactured in common sizes with potential large capacity gaps between sizes – which often necessarily leads to system upgrades that have spare hosting capacity that can be utilized by future interconnecting DERs.[28] Future interconnecting DERs, therefore, directly benefit from the previous system upgrade under the Cost Causation Principles – a concept that is typically referred to as "free ridership.". The reimbursement approach attempts to address the free ridership created by allocating all upgrade costs to one interconnecting facility. It does so by both identifying specific equipment that provides shared benefits and assigning the associated costs to future interconnecting DERs.

Of course, the elements of the Cost Causation Principle that remain within the reimbursement approach continue to pose the same barriers. Because the reimbursement approach still requires the marginal developer to pay for the entire system modification upfront, that developer may still have to abandon the project after having delayed the interconnection queue. However, the possibility of future reimbursement would likely reduce developer risk and encourage investment in the upfront system modification. There is no guarantee that other developers will interconnect using their upgrade and reimburse them for it, but it is a distinct possibility, where before it was not.

The reimbursement approach aligns with our cost allocation principles. Assigning costs to future DER interconnectors embodies the direct beneficiaries pay principle. In this case, subsequent developers who benefit from the original upgrade pay for their share of its use, which – if utilized as intended – is a more equitable and efficient method of resource allocation. The reimbursement approach also promotes the differentiation principle by identifying specific equipment that is utilized by direct beneficiaries and relies on transparent cost tracking for implementation of the approach. Finally, the reimbursement approach supports the efficient GHG reduction principle, as any efficiencies and cost reductions that lead to more DER development will also promote efficient GHG reduction.

Massachusetts had a requirement similar to the reimbursement approach under the group study process pilot. It is unclear whether this process has been used or whether it still applies, given that the group study pilot has ended. Under the initial group study, when a "new Facility interconnects to the circuit that was the subject of the Group Study within 5 years, that Interconnecting Customer shall be assessed System Modification costs consistent with the

[28] Section 5.4: Separation of Costs in the Standards for Interconnection of Distributed Generation states that "Should the Company combine the installation of System Modifications with additions to the Company's EPS to serve other Customers or Interconnecting Customers, the Company shall not include the costs of such separate or incremental facilities in the amounts billed to the Interconnecting Customer for the System Modifications required pursuant to this Interconnection Tariff. The Interconnecting Customer shall only pay for that portion of the interconnection costs resulting solely from the System Modifications required to allow for safe, reliable parallel operation of the Facility with the Company EPS." While this requirement is not entirely start forward, our interpretation of this section would still lead to lumpy investments. The distinction is that just because an investment is lumpy, does not suggest that it is "separate or incremental."

Company's line extension policy."[29] Additionally, the group study cost allocation approach exempted facilities that went through the simplified process. While the methodology for allocating system upgrade costs is not completely transparent nor included in the EDCs' line extension tariff, the concept of cost allocation within the group study appears similar to the reimbursement approach.[30]

Two other jurisdictions have adopted mechanisms similar to the reimbursement approach. The New York Public Service Commission ("NY PSC") adopted this mechanism alongside its queue management plan in early 2017. The NY PSC recognized that "the lack of a method for allocating the costs of substation upgrades among DER projects presents a barrier to the fulfillment of REV policies."[31] Similarly, the United Kingdom has a clause in its Common Connection Charging Methodology that addresses recovery of costs for previous works. Developers in the UK utilizing a distribution system asset that was installed for and paid by another customer may need to pay that other customer within the applicable time period.[32] In both New York and the UK, cost sharing via subsequent reimbursement was seen as improving the interconnection process. This proposal, too, envisions subsequent reimbursement as an interconnection improvement for Massachusetts.

Reimbursement Case Study: NY PSC 16-E-0560 (2017)

The basics: In 2017, the NY Public Service Commission approved a temporary cost allocation proposal[33] that would require reimbursement of certain shared system upgrades. The first project triggering the upgrade pays the entire upgrade cost upfront, and subsequent interconnecting projects reimburse the original project developer according to their share of the watts served by the upgrade. The mechanism finishes once the capacity of the upgrade is exhausted or the net cost to the participating projects falls to $100,000 or below. NY utilities administer the reimbursement process and collect a $750 fee from developers for processing each reimbursement.

The details: The cost sharing applies only to substation $3V_0$ installation, substation transformer upgrades, and other substation-level shared upgrades. The upgrade must exceed $250,000 to trigger the sharing mechanism. Projects below 200 kW AC are excluded from cost sharing, except when a single developer aggregates smaller projects within eight months of one another that together exceed 200 kW AC.

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[29] *See* Standards for Interconnection of Distributed Generation, Section 5.3: System Modification Costs.
[30] *See* https://www9.nationalgridus.com/non_html/Dist%20T&Cs%20(1192)_12.01.10.pdf While it is clear that system modification costs are assessed to interconnecting facilities outside of the initial group study, it is unclear what party obtains the funds collected through the Company's line extension and the proportion of the system modification costs that are collected.
[31] *Modifications to the New York State Standardized Interconnection Requirements,* New York Public Service Commission Case 16-E-0560, Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings at 29 (January 25, 2017), *available at* http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-E-0560&submit=Search.
[32] UK Distribution Connection and Use of System Agreement (DCUSA). Schedule 22: Common Connection Charging Methodology (CCCM). At 866.
[33] New York Public Service Commission Case 16-E-0560, Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings.

What's next: New York's cost sharing arrangement expires for new upgrades after December 31, 2020. In the Order approving the mechanism, the PSC directed NY's Interconnection Policy Working Group (IPWG) to see if it can find a "better approach" to cost allocation than the post-upgrade reimbursement method.[34] The IPWG continues to deliberate various approaches, most recently publishing its cost sharing progress in October 2019 and not yet identifying the structure for a future mechanism.[35]

Steps for Massachusetts

Massachusetts can use New York's example as a guide for several key design components of the reimbursement mechanism and combine those with components of the group study cost allocation approach.

A. Determining what upgrades qualify for reimbursement.

An important first detail New York clarified was which system upgrades qualify for future reimbursement. The criterion used to identify qualified system upgrades were those "that can be used by more than one project." Using this criterion, the New York PSC identified substation 3V0 installations, substation transformer upgrades, and other substation-level shared upgrades. New York's process illustrates how stakeholders can identify system upgrades that create direct benefits to specific interconnecting DER facilities.

Massachusetts does not appear to differentiate between distribution upgrade type. The DPU and other stakeholders should examine whether all types of upgrades should be shared or whether it would be more equitable to focus on specific upgrade types. New York noted that the characteristics of the interconnection queue led it to focus on specific system upgrade types, which may be important to replicate here.

B. Cost threshold

To ensure administrative efficiency, a minimum system upgrade cost threshold should be determined. New York determined an upgrade cost threshold of $250,000 or more are eligible for reimbursement. The lack of data available in Massachusetts, however, presents a challenge in setting such thresholds now. Utilities should provide any available historic or projected interconnection cost data to the DPU and stakeholders to help inform a minimum system upgrade cost threshold. If no such interconnection cost data exists, estimated installed cost data associated with the qualified system upgrades could be used to inform a threshold.

C. Minimum DER capacity

Determining a minimum DER capacity for cost sharing is one parameter that could reduce administrative burden. New York exempted projects below 200kW from reimbursing earlier upgrade costs. The Massachusetts group study cost allocation approach only exempted small

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[34] *Id*. at 29.

[35] "Upgrade Cost Sharing V2." Interconnection Policy Working Group Meetings and Documents. http://www3.dps.ny.gov/W/PSCWeb.nsf/All/0D7596DBBEF0380885257FD90048ADFA?OpenDocument (October 23, 2019).

facilities that qualified for the simplified process. It appears reasonable to apply the parameter used in the group study to the individual reimbursement approach.[36]

D. Expiration of reimbursements

Finally, the reimbursement approach likely requires a parameter that stops the reimbursement process using a monetary and temporal threshold. New York determined that cost sharing stops when costs to all participants falls below $100,000, while the group study cost allocation approach had a temporal limit of 5 years. It seems reasonable to adopt both a temporal and monetary threshold for the individual reimbursement approach.

There may be additional relevant criteria or thresholds that could be included within Massachusetts. Further analysis on the current interconnection queue and stakeholder input could provide more insight. The thresholds discussed above are a first attempt to providing needed structure for the reimbursement approach to be implemented in a short time period. Additionally, the New York tariff language is included as Appendix B.

2. Group Study

The Department should prioritize its resolution of the group study framework for DER interconnection cost allocation. Under a group study, multiple DER interconnection projects undergo a combined system modification study, thereby sharing responsibility upfront for system upgrade costs. We recognize that Massachusetts had a year-long group study pilot in 2015 and that the EDCs proposed a longer-term group study process in 2017 that is currently under discussion in D.P.U. 17-164. Given the on-going status of the current docket, we refrain from addressing substantive group study issues in this proposal.

However, we emphasize that we consider group study to be one of the most important alternate cost allocation methods for improving upon the Cost Causation Principle. We support a timely resolution in D.P.U. 17-164 so that a well-designed group study option can be considered and implemented alongside the other near-term solutions described in this proposal.

Group study is a critical cost allocation method for several reasons. Most importantly, it satisfies the beneficiary pays principle, ensuring that direct beneficiaries pay for the benefits they receive from system upgrades. Instead of assigning the cost of a system upgrade to the single triggering developer and allowing future developers to free ride upon that solo investment, it holistically evaluates all projects in a geographic area for their joint system impacts and charges them accordingly. Those project developers will face a lower upfront cost burden than they otherwise would have had they been the initial triggering developer and may therefore be more likely to see their project through. Group study can also promote administrative efficiency as compared to evaluating each developer in an interconnection queue individually and sequentially. The time saved can allow developers to more easily secure project financing and take advantage of time-sensitive policy incentives.

[36] Alternatively, match to any updates to the Group Study process regarding minimum capacity pursuant to D.P.U. 17-164.

Not only does the group study allow for immediate cost sharing by those directly participating in the study, but consistent with the reimbursement proposal above, it requires future direct beneficiaries to pay a portion of system modification costs as well. Much clarity is still needed as to how the group study cost allocation approach would be, or potentially was, applied. Among other questions, the current tariff language is unclear about: (1) which party benefits from the assessed system modification costs collected through line extension policy (*i.e.,* is this a reimbursement mechanism); (2) the proportion of costs that are, or can be, assessed through line extension fees; and (3) how the costs are incorporated into the line extension policy. The cost allocation process utilized for the approved group study process should be consistent with the final individual reimbursement approach determined from the preceding section.

Like all cost allocation methods, the group study is not perfect. Developers can drop out of the process, forcing the remaining projects to wait for a new study and pay its additional cost. Other jurisdictions have concluded, however, that it is a time-efficient cost allocation solution. In North Carolina, for example, Duke Energy recently responded to the North Carolina Public Utilities Commission's direction to file a queue reform proposal by designing a grouping study specifically envisioned to reduce interconnection backlog.[37] Group study remains one of the most promising ways to reform the Cost Causation Principle.

3. Power control limiting

Power control limiting is the first of two methods we propose for capacity interruption as a method of cost allocation. Under power control limiting, an interconnecting DER can limit its capacity or its imports and exports in order to avoid triggering system upgrades.[38] Imposing a static limitation ensures that the DER does not result in any system upgrades. Here, a power control limitation would be proposed by the DER applicant as part of the interconnection application process.

The power control limiting proposal satisfies the cost allocation principles of beneficiary pays, differentiation, and transparency. The developer benefits from avoiding the cost of a system upgrade and "pays" by instead forgoing some of the facility's output. The power control limiting proposal also satisfies the efficient GHG reduction principle in that efficiencies and cost reductions that lead to more DER development will promote this principle. The power control limiting approach differentiates cost allocation methods by acknowledging that different system configurations can avoid causing costs to non-participants, while allocating all costs to the direct beneficiary – improving system efficiency with increased hosting capacity. This approach also relies on transparency. Implicitly, the interconnecting facilities will need to be aware of the system

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[37] *Model Small Generation Interconnection Standards & Associated Application to Interconnection & Interconnection Contract Forms*, North Carolina Utilities Commission, Docket E-100 Sub 101, DEP and DEC Queue Reform Update (October 15, 2019), *available at* https://starw1.ncuc.net/NCUC/page/docket-docs/PSC/DocketDetails.aspx?DocketId=b8c5f6f2-943d-4504-8cdf-718f5ca434de.

[38] Energy storage could also enable this flexibility without sacrificing facility output. Perhaps developers could have an option to reduce AC inverter size if within some threshold for upgrade. This would allow different configurations including storage, but also simply a higher inverter loading ratio. Strategen is aware that there may be overlap between the issues covered here and other conversations happening related to D.P.U. 19-55. However, we believe these issues to be directly related to cost allocation and therefore need to be resolved somewhere within the docket.

constraint that is causing the need for power control limiting. For this reason, the approach relies on transparent data provided by the interconnecting utility.

The Minnesota Public Utilities Commission recently approved a power control limiting mechanism as part of its Technical Interconnection and Interoperability Requirements (TIIR).[39] The power control option was developed as part of the IEEE 1547 implementation process, which was intended to improve interconnection efficiency. Specifically, the Minnesota TIIR states that a DER operator may choose to use power control limits "to avoid system upgrades."[40] The process utilized in Minnesota requires communication between the DER operator and the utility; "The use and method for Power Control limiting shall require approval from the Area (Electrical Power System) Operator." During the interconnection review process, at least one utility in Minnesota identifies the threshold size that triggers a system upgrades and the DER operator has the option to reduce its size physically or using power control limiting. [41] Additionally, the Minnesota TIIR requires that the utility "review and either approve the proposed Power Control method and settings or provide a response as to why the method does not provide adequate control."[42] Providing interconnecting DER the option to utilize power control limiting allows the operator to be allocated a small cost to avoid a more substantial system upgrade.

Massachusetts could utilize a process similar to that of Minnesota as a form of cost allocation. By simply providing DERs with the option to utility power control limiting, the state could increase utilization of distribution system assets and more equitably allocate interconnection costs. With sufficient information from the DER applicant, the interconnecting utility would be able to assess the viability of the power control limitation for their distribution system during the study process.

4. Dynamic curtailment pilot

A second capacity interruption cost allocation method is for Massachusetts to establish a dynamic curtailment pilot program. Under this program, a developer interconnecting to a congested circuit agrees to an estimated amount of DER export curtailment as an economic alternative to otherwise necessary system modification costs. In the short term, such a pilot could be used to address immediate constraints on a congested circuit. Detailed reporting criteria would be required from the EDCs if this option is implemented.

In the context of DER interconnection, dynamic curtailment is also known as flexible interconnection or interruptible interconnection. Like power control limiting, this arrangement allows the DER to interconnect without triggering and paying for system upgrades. Unlike power control limiting, it is a more dynamic form of capacity interruption under which a developer must

[39] *Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities*, Minnesota Public Utilities Commission Docket 16-521, Order Updating Technical Interconnection and Interoperability Requirements (TIIR) at 30 (January 22, 2020), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={80F9CE6F-0000-CD7F-B49D-578DE697D2C8}&documentTitle=20201-159427-04.
[40] *Id.* at 31.
[41] *See* State of Minnesota, Distributed Energy Resources Interconnection Process (MN DIP v.2.3) as approved by the Minnesota Public Utilities Commission (April 19, 2019), *available at* https://mn.gov/puc/assets/Minnesota%20Distributed%20Energy%20Resource%20Interconnection%20Process%20and%20Agreement%20%28MN%20DIP%20and%20DIA%29_tcm14-381183.pdf
[42] *Id.*, at 32.

agree to allow the system operator to curtail their output during times of high system penetration and low absorption. Dynamic curtailment has been trialed extensively in the UK, including by Distribution Network Operators (DNOs) Western Power Distribution and UK Power Networks. Both DNOs now intend to bring the pilot to scale as "business as usual" on their systems. National Grid is also working on a flexible capacity pilot project in New York (see case study section for more information).

Like power control limiting, this cost allocation method satisfies the principles of beneficiary pays and differentiation. The direct beneficiary pays the curtailment costs. By differentiating systems based on the possibility of economic curtailment for a given system configuration, there can be fewer system upgrades and faster interconnections. As noted above, any efficiencies or cost reductions that lead to more DER development also promote the principle of efficient GHG reduction.

There can be many benefits of a dynamic curtailment pilot. The primary benefit is avoiding system upgrades in the first place. It can also reduce the cost of interconnection agreements. It can also save time on connections to heavily constrained networks by avoiding construction delays. Finally, it can cause a higher acceptance rate for interconnection agreements, which in turn means more DER and a more efficient and effective interconnection queue.

An Active Network Management pilot by the DNO UK Power Networks achieved all of these benefits: the pilot saved approximately $44 million (approximately $36 million when including the cost of ANM and curtailment); it reduced connection lead times by over 57%, or an average of 29 weeks; and it saw 33% acceptance on flexible interconnections versus 20% acceptance on business-as-usual.[43]

Dynamic Curtailment Case Study

The basics: Western Power Distribution (WPD), one of the electricity distribution network operators in the United Kingdom, ran its Lincolnshire Low Carbon Hub project from 2012 to 2015 to test techniques for integrating clean, distributed generation into its electric distribution network without the costs and issues associated with traditionally-necessary network reinforcements. It piloted Alternative Connections Agreements in which generators agreed to "operate in a suitable reactive power control mode and to constrain active power export when required," which created capacity for additional generation but avoided triggering network reinforcements.[44]

The details: Alternative Connections Agreements are paired with hardware for Active Network Management (ANM). The ANM scheme was integrated into WPD's Network Management Software (NMS), allowing the operator to constrain DG power export when the system would otherwise exceed its design limits. At the same time, new software for network planning and

[43] UK Power Networks, Flexible Plug and Play Close Down Report, 2015, *available at* https://innovation.ukpowernetworks.co.uk/wp-content/uploads/2019/05/FPP-Close-Down-Report-Final.pdf.
[44] LCN Fund Project Close Down Report, Low Carbon Hub, Western Power Distribution 2015, at 7, *available at* https://www.westernpower.co.uk/documents/.

constraint analysis allowed for "greater visibility of the network power flows" under the new interconnection paradigm.[45]

The results: WPD began offering Alternative Connection Agreements in East Lincolnshire in 2014 as an alternative to expensive conventional network reinforcement. Six developers have accepted Alternative Connections for a total of 48.8 MVA in new connections and an estimated $55 million cost savings.[46]

What's next: The project in East Lincolnshire was WPD's first ANM implementation, and it has since committed to implement Alternative Connections across all four of its license areas by 2023, using the agreements developed through this project. WPD has undergone internal implementation to make these agreements business-as-usual, including writing official ANM policies, training its 200+ staff planners on offering agreements, and developing a core constraints analysis tool.[47]

Steps for Massachusetts

Massachusetts can use the successful examples from the UK as guidance for designing its own curtailment pilot. It can also leverage any similarities from National Grid's flexible interconnection pilot in New York. The DPU can establish a general framework based on the best practices and lessons learned in the UK, then direct the EDCs to propose their own pilots and to report on them.

The most important pieces of the curtailment framework will be the legal and commercial structures for enabling the mechanism and the technology for carrying out dynamic capacity interruptions. The following paragraphs summarize these structures, while Appendix C breaks out their components in greater detail.

In the UK, establishing legal and commercial frameworks for curtailment includes developing principles of access that define how interconnecting DER facilities would be prioritized under curtailment, and developing an official interconnection agreement that includes dynamic curtailment. Processes that Massachusetts could follow to ensure that these structures are built to be well-suited to the jurisdiction and its interconnecting DER facilities call for expert and stakeholder engagement processes.

In the UK, identifying and acquiring the necessary technology for curtailment focused on Active Network Management software. While this software will likely be necessary in Massachusetts as well, the DPU may wish to guide a process to help determine all the ancillary components to the software acquisition and use, such as data reporting, communication, and other implementation overlaps.

To begin the pilot, the DPU should direct each EDC to select an area suitable to develop a dynamic curtailment with an explanation of why the selected area will provide the greatest benefit to ratepayers.

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[45] *Id.*
[46] *Id.*
[47] *Id.* at 52.

Conclusion

D.P.U. 19-55 opened a discussion of methods for allocating the costs related to DER interconnections that require distribution system modifications. The current cost allocation mechanism, cost causation, in some instances, is not sufficient for interconnecting high levels of renewable DER into the distribution system.

Four guiding principles inform the alternative cost allocation mechanisms in this proposal: beneficiary pays, differentiation, efficient GHG reduction, and transparency. Steered by these principles, the proposed cost allocation mechanisms can improve DER interconnection and cost allocation in the near term. They have all been implemented in other jurisdictions and can be tailored to the Massachusetts context by building off the successes and lessons learned in each example.

For residential and small commercial facilities, this proposal maintains the status quo which exempts those projects from paying for system modification costs. In the name of transparency, it suggests tracking and compiling comprehensive data on any system upgrades that small projects do trigger.

For medium and large facilities, this proposal identifies several complementary cost allocation mechanisms that together can holistically improve upon the Cost Causation Principle and its insufficiency for allocating DER interconnection costs. Requiring developers to reimburse system upgrade costs from which they benefit is a first step in moving away from the inequity of cost causation. Implementing a group study process to allow for simultaneous engineering and cost studies that automatically split those costs among the group members mitigates many of the problems with the current Cost Causation Principle. Building a process that normalizes static and dynamic DER export control allows developers to create system efficiencies by avoiding system modification costs in the first place.

These proposals together represent a set of solutions that address current cost allocation inequities and could help alleviate prevalent queue management issues in the Commonwealth. With a minimal amount of stakeholder process, they can be adapted to fit Massachusetts' interconnection process and begin yielding benefits to interconnection participants in the state.

Appendix A: Case Study of Preemptive Utility Upgrade

Preemptive utility upgrade is a cost allocation method that was not included in this proposal because it is out of the scope of the D.P.U. 19-55 docket. Because this mechanism will be increasingly utilized in some jurisdictions, it is important to be aware of it in any cost allocation discussion. The following case study describes this mechanism for the benefit of decision-makers' future reference and consideration.

Under this cost allocation method, the utility proactively conducts a network upgrade, which future interconnecting projects must pay back when they utilize the upgraded capacity.

Pros:

- Marginal developer does not have to pay upfront capital costs
- Ideally, upgrade costs are shared among those who benefit

Cons:

- Risk is transferred to ratepayers
- Upgrade costs are unnecessarily paid by ratepayers if developers do not interconnect
- Misaligned incentives: there's little incentive for a utility to seek developers to interconnect
- Scale: it's difficult to prescribe how many preemptive upgrades can achieve the intended results

Mechanism in Practice: National Grid (NY) REV Pilot

The basics: In 2017, National Grid filed and implemented a Distributed Generation Interconnection REV Demonstration Project, in which it installed $3V_0$ ground fault protection (a "common-system upgrade") at two substations to make the system in those areas "DG-ready."[48] All future applicants to connect to the upgraded substations with DER systems above 50 kW must pay National Grid a prorated fee. If National Grid cannot recoup the upgrade costs through those fees, it will pass them onto ratepayers through a regulatory asset in a future proceeding.

The details: Interconnecting developers will pay the full cost of the upgrade, though they will only be allotted 80% of the capacity, so that smaller projects (under 50 kW) can take advantage of the remaining 20% of upgraded substation capacity free of charge.[49] The Company has also defined a marketing plan for engaging potential and existing DER applicants, which they tout as a departure from the usual developer or customer-initiated interconnection

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[48] *Reforming the Energy Vision*, New York State Department of Public Service Case 14-M-0101, National Grid Distributed Generation Interconnection REV Demonstration Project - Implementation Plan at 3 (May 24, 2017), *available at* http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101.
[49] *Id.*

request.[50] A developer may still choose to use New York's existing cost allocation model instead, which was outlined in the previous case study.

The results: According to the Company's most recent quarterly report, it "was able to secure a sufficient level of DG interconnection applications for each substation to fully subscribe the available hosting capacity."[51] National Grid continues to monitor and report on the interconnection queue status in its quarterly reports.

What's next: In its 2017 implementation plan, the Company stated that the "Demonstration Project is highly scalable." It remains to be seen whether this is true. However, the Company has been approved to initiate a second project phase with a focus on targeting DER development on landfills and brownfields, proactive outreach to municipalities and communities in these targeted areas, and new technology testing.

Specific example (from National Grid Initial Proposal):

Calculation of DG Interconnection Rate

COSTS SHOWN HERE ARE ILLUSTRATIVE ONLY.

		Peterboro Substation		East Golah Substation	
1	**Estimated Common Costs**				
2	3V0 Upgrades	500,000		500,000	
3	Other Costs	-		100,000	
4	Total Estimated Common Costs		500,000		600,000
5					
6	**Billable Units**				
7	Transformer Rating	27,500		29,180	
8	% of Projects Greater than 50 kW	80%		80%	
9	Billable kW		22,000		23,344
10					
11	Tax Gross Up		39.225%		39.225%
12					
13	Rate per installed kW		$ 37.40		$ 42.29

2	Engineering Estimate
3	Engineering Estimate
4	Line 2+ Line 3
7	Engineering Estimate
8	Engineering Estimate
9	Line 7 * Line 8
11	State and Federal Income Tax
13	(Line 4 / Line 9) / (1-Line 11)

*The fee will be based on estimated costs (which are currently being developed). Estimates will be trued up to actual costs.

[50] *Id.* at 4.

[51] *Reforming the Energy Vision*, New York State Department of Public Service Case 14-M-0101, National Grid Quarterly Report – Q3 2019 (October 31, 2019), *available at* http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101.

Appendix B: New York Upgrade Cost Reimbursement Mechanism

Limited Mandatory Interconnection Upgrade Cost Sharing Mechanism.[52]

This interim cost sharing mechanism applies to any initial projects that meet all of the following criteria:

1 Use Eligible Technologies.

This mechanism is applicable to projects and technologies interconnecting to the distribution grid under the SIRs, using state jurisdictional rates.

2 Cost Sharing is Not Retroactive.

This mechanism is not available to projects that have 100% paid for upgrade costs, or were required to have paid for upgrade costs prior to January 25, 2016. Any project that makes 100% payment of upgrade costs after January 25, 2017, is eligible for cost sharing.

3 Specific Eligible Upgrades.

This mechanism applies to upgrades that can be used by more than one project. Specifically, the following technologies are eligible for interim cost sharing:

3.1 Substation 3V0 installation;
3.2 Substation transformer upgrades; and
3.3 Other substation-level shared upgrades.

4 Minimum Cost Threshold.

The mechanism is limited to eligible upgrades that cost $250,000 or more.

5 Applicability.

This mechanism applies to subsequent projects that will utilize the upgrades and meet the following criteria:

5.1 Projects 200 kW or Greater in Size - Any subsequent project that is equal to, or greater than, 200 kW at one point of common coupling (PCC) and uses the upgrade will share in the upgrade cost according to this mechanism.

5.2 Projects Aggregating to 200 kW or Greater in Certain Situations - Subsequent projects that utilize the upgrades, which are completed by a single developer and are equal to, or greater than, 200 kW in aggregate, and whose applications are filed within eight-months of each other.

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[52] This text has been directly transcribed from *Modifications to the New York State Standardized Interconnection Requirements*, New York Public Service Commission Case 16-E-0560, Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings, Attachment A at 8 (January 25, 2017), *available at* http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=51822.

5.3 A developer is defined as the entity that submitted the interconnection application. A single developer includes all legal entities associated or affiliated with a given company, including subsidiaries, LLCs, etc.

6 Payment.

The mechanism will function as follows:

6.1 The initial project that triggers the need for the eligible upgrade pays 100% of the upgrade cost in accordance with the SIRs deadlines. The cost sharing mechanism is available after the initial project developer pays 100% of the required upgrade costs. The interconnecting utility shall disclose the portion of the total upgrade cost that is eligible for this mechanism to the initial project developer in the CESIR, or in the Preliminary Technical Report or Supplemental Review Report if no CESIR is required.

6.2 Subsequent project developers are required to pay their prorated share of the eligible upgrade cost. This payment is made to the utility and then passed through to the project developer(s) that have previously paid for the upgrade, minus a utility processing fee. The developer(s) are responsible for any reallocation of received funds to project financiers or owners, per their own business arrangements. For all types of eligible upgrades, the prorated share for projects after the initial triggering project is based on the fraction of each MW project size compared to the total MWs of aggregated projects benefiting from the upgrade to date, including the newest project's MWs. Please see the examples below under "Mechanics of the Cost Sharing Program" for more details. Each project developer's prorated share of the upgrade cost will be included in the CESIR, or in the Preliminary Technical Report or Supplemental Review Report if no CESIR is required.

6.3 Utilities shall deduct a processing fee from each subsequent developer check issued after the initial developer pays 100% of the upgrade costs. This $750 administrative fee may be reassessed if it is proven inadequate in practice.

7 Cost Sharing Limit.

The first of the below events to occur triggers the end of the cost sharing of an upgrade:

7.1 Maximum Capacity

When the capacity of the upgrade is exhausted by projects, this limited mandatory interconnection cost sharing mechanism ends.

7.2 Cost Sharing Threshold

When project developers benefitting from the eligible upgrade have expended net costs of $100,000 or less, because each developer was reimbursed by subsequent developers, cost sharing ends. Project developers that use the eligible upgrade after this point incur no mandatory interconnection upgrade cost sharing.

8 Mechanics of the Cost Sharing Program

8.1 “Company A” has a 2 MW AC project that has a CESIR that includes a $400,000 3V0 upgrade for the substation. Company A pays that full cost, and their project, “Project #1”, moves forward.

8.2 “Company B” is next in line with a 2MW AC project (“Project #2”), and it’s CESIR also confirms the necessity for it to utilize 3V0 at the substation. The utility already knows that Company A has signed the contract for the 3V0, so it simply does the calculation to determine the pro-rata share that Project #2 will be utilizing (i.e. this is Project #2’s share of the capacity using the upgrade to date). In this example, that would be 50%, so Company B would be given a cost of $200,000 for the 3V0 in its CESIR. Assuming that Project #2 moves forward, Company B would pay that $200k for the 3V0, along with its other IC costs, and the utility would then send a check for that $200k minus the $750 processing fee to Company A. For the sake of clarity, the formal way to calculate this cost is to take the total upgrade cost of $400,000 divided by the total AC watts now served (4,000,000) which results in a cost of $0.10 per AC watt. Project #2 would then be quoted a cost of 2 MW AC or 2,000,000 AC watts times $0.10 per AC watt which equals $200,000.

8.3 Next, Company C comes along with a 1.2MW AC project (“Project #3) and their CESIR also states the need for 3V0. That would mean that the total amount of watts that would be utilizing the 3V0 would now be 5.2 MW AC, or 5,200,000 watts AC. The total cost of $400,000 is divided by the total watts served by the upgrade (5,200,000) which results in $0.076923 per AC watt. Project #3 is quoted a cost of 1,200,000 AC watts times $0.076923 which equals $92,307.60. If Company C moves forward and pays its fee, both Company A and Company B will get a check from the utility for $46,153.80, each minus the $750 processing fee. The division of Company C’s payment between Company A and Company B is based on the ratio of each of those previous projects in MWac to the project total in MWac using the upgrade before the payment in question.

8.4 After the reimbursements detailed above with these three example projects using the upgrade, Project #1 has paid $153,846 of the total cost plus a $1,500 in processing fees, Project #2 has paid $153,846 of the total cost plus $750 in processing fees, and Project #3 has paid $92,307.60. Because all three projects have not reached a final cost share of less than the above Sharing Cost Threshold, additional projects that use the upgrade would continue to pay their share until each project’s share after reimbursements is equal or less than the Sharing Cost Threshold, until the capacity of the upgrade is used up, or until December 31, 2020, whichever comes first.

Appendix C: Dynamic Curtailment Process Straw Proposal

Procedural steps to develop a Dynamic Curtailment pilot[53]

- Identify and develop the necessary legal/commercial frameworks and technology for interruptible interconnections
  - Develop legal/commercial frameworks:
    - Stakeholder engagement
      - Evaluate developer interest in curtailment
      - Learn developer concerns with curtailment/conditions for participation
      - Identify improvements to flexible interconnection process
      - Recruit potential developers for signing interruptible agreements
    - Expert engagement
      - MA utilities should reach out to UK DNOs who have implemented these types of agreements and are now incorporating them for business as usual
      - Engage internal experts from National Grid (NY), who is working closely with a UK partner to implement ANM software
    - Develop principles of access
      - Defines relationship and connection priority of multiple interruptible DERs within the pilot.
      - Potential options:
        - Last in first out (LIFO)
          - The last DER to join the network is curtailed first
          - Transparency: allows developers to model their expected curtailment based on a fixed position for access to capacity
        - Pro rata
          - Curtailment divided among all DERs contributing to constraint (based on ratio of DER output to curtailment)
          - Fairness: shared curtailment means equal access for all DERs
          - But uncertain for developers; individual curtailment would increase each time a new DER connects

[53] This description draws extensively on information in the final reports from the UK trial projects Flexible Plug and Play and Low Carbon Lincolnshire and on Avangrid NY's FICS Implementation Plan. The process would need to be specifically tailored to Massachusetts under the needs of D.P.U. 19-55. *See* UK Power Networks, Flexible Plug and Play Close Down Report 2015, *available at* https://innovation.ukpowernetworks.co.uk/wp-content/uploads/2019/05/FPP-Close-Down-Report-Final.pdf; Western Power Distribution, Low Carbon Hub LCN Fund Close Down Report 2015, *available at* https://www.westernpower.co.uk/documents/; *Reforming the Energy Vision*, New York State Department of Public Service Case 14-M-0101, Avangrid Reforming the Energy Vision Demonstration Project: Flexible Interconnect Capacity Solution - Implementation Plan (January 8, 2016), *available at* http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101.

        - Based on DER size
        - Based on DER carbon benefit
    - Develop interruptible interconnection offer
        - Ensure flexibility so curtailment practice is removed if future upgrade occurs
- Acquire needed technology
    - Active Network Management software
        - Actively manages power flows, power constraints, and voltage levels
        - Need to design specifications
            - Hardware and software
            - Data requirements
            - Communication links
            - Necessary testing
- Determine cost recovery

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Cost of Service Analysis

DER Compensation

Rate Case Support

Electric Vehicles

Renewable Energy Program Design

Expert Testimony

Pennsylvania Power and Light, DER Management Plan, P-2018-3010128

Public Service of New Hampshire d/b/a Eversource, Petition for Permanent Rate Increase, Docket No. DE 19-057

Oklahoma Gas & Electric, Formula Rates and Rate Design, Docket No. 201800140

Experience

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Strategen – Portland, OR
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Designing policies and programs to advance deployment of distributed energy resources, demand-side management programs, energy storage and grid integration.

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Publications & Speaking

Using Low Carbon Fuel Standard Proceeds from EV Adoption to Improve the Efficiency of Electricity Rates”. *Berkeley Public Policy Journal*. September 2019.

Integration of renewable energy in Greek energy markets: A case study”. 2nd HAEE International Conference, May 2017

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Provided technical assistance to Massachusetts local governments on renewable energy technology and energy planning. Authored white paper on clean heating and cooling technologies, policies, and opportunities for municipalities.

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B.A. Chemistry, Princeton University, 2007

M.S. Sustainability, Arizona State University, 2011

P.S.M. Solar Energy Engineering and Commercialization, Arizona State University, 2012

Domain Expertise

Avoided Cost Modeling

Rate Design

Energy Resource Planning

Benefit Cost Analysis

Stakeholder Engagement

Energy Policy & Regulatory Strategy

Energy Product Development & Market Strategy

Expert Testimony

National Grid, Electric Vehicle Infrastructure Program, Docket No 18-150

Experience

Senior Director
Strategen – Berkeley, CA
May 2017 – Present

Policy and regulation of the electric power sector with a focus on economic analysis, technical regulatory support, resource planning and procurement, utility rates, and policy & program design.

Consultant
Kris Mayes Law Firm – Phoenix, AZ
June 2012 – March 2015

Consulting on policy and regulatory issues related to the electricity sector in the Western U.S.

Consultant
Schlegel & Associates – Phoenix, AZ
November 2012 – March 2015

Conducting analysis and helping draft legal testimony in support of energy efficiency for a utility rate case.

Project Manager & Researcher
Arizona State University – Temple, AZ
June 2012 – March 2015

Conducting research and managing projects on energy policy, utilities and new regulatory models.

Research Fellow
Environmental Defense Fund – New York, NY
July 2007 – July 2009

Research and policy analysis in support of EDF's policy efforts at local, state, and national level.