COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

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

COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL, INC. ON THE DISTRIBUTED ENERGY RESOURCE PLANNING PROPOSAL

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I. Introduction

On October 22, 2020, the Department of Public Utilities (the "Department" or "DPU") issued a Vote and Order Opening Investigation ("Order") in the above-captioned docket. In the Order, the Department proposed a new distributed energy resource planning process and cost allocation procedures ("Straw Proposal") and invited comments on the Straw Proposal and related cost allocation issues. The Interstate Renewable Energy Council, Inc. ("IREC") appreciates this opportunity and hereby timely submits the following comments on these topics.

IREC is a 501(c)(3) non-partisan, non-profit organization working nationally to build the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy, and our planet. In service of our mission, IREC advances scalable solutions to integrate distributed energy resources ("DERs"), e.g., renewable energy, energy storage, electric vehicles, and smart inverters, onto the grid safely, reliably, and affordably. The scope of our work includes developing and advancing regulatory policy innovations; generating and promoting national model rules, standards, and best practices; and updating interconnection processes to facilitate deployment of DERs and remove constraints to their integration on the grid.

The Department opened this docket in recognition that the traditional, cost-causer-pays method of allocating interconnection upgrade costs is failing to facilitate the Commonwealth's clean energy mandates. While this cost-causer approach is easy to administer, the practical impact is that—especially as DER penetration increases like it has in Massachusetts—otherwise viable projects can be abandoned in the face of high upgrade costs. Indeed, an upgrade necessary to accommodate future DER can be so high as to effectively close a circuit, even for larger projects.

We also support the Department's investigation here in the interest of fairness. The cost-causer-pays approach is frequently unfair, as luck of the draw determines which projects pay for upgrades. For example, a large, 2 MW project could interconnect and use up all remaining capacity on the circuit, but not have to pay any upgrade costs. This large project could be followed in the queue by a smaller, 200 kW project that could not afford the cost of the now-necessary upgrade, and is thus effectively shut out simply due to the luck of where it fell in line. Any of the cost allocation proposals considered here would help minimize or eliminate this unfairness by spreading costs across projects that contribute to the need for upgrades.

IREC has worked on cost allocation issues across the country, advocating for more fair distribution of DER upgrade costs across interconnecting projects. We are strongly supportive of the Department's efforts here and draw on our experience to provide these comments.

II. Distributed Energy Resource Planning

IREC is strongly supportive of proactive distribution planning in Massachusetts, especially due to the Commonwealth's constrained electric infrastructure and the continued and rapid growth of its distributed energy resources. As a general matter, IREC, in partnership with Sandia National Laboratories, developed the concept of "Integrated Distribution Planning" to encourage a proactive approach that moves away from responding to individual interconnection requests and associated grid upgrade fees on a project-by-project basis and toward a methodology of forecasting DER growth and planning for grid upgrades in response.[1] We are

[1] Interstate Renewable Energy Council & Sandia National Laboratories, *Integrated Distribution Planning Concept Paper: A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources* (May 2013), *available at* https://irecusa.org/publications/integrated-distribution-planning-concept-paper/ (hereinafter "Integrated Distribution Planning Concept Paper").

supportive of the Department's approach in the instant proposals, though a number of crucial questions remain unanswered, which could determine the ultimate success or failure of the proposed planning and cost-allocation mechanisms. Below, we offer several comments and recommendations on areas for further development of the Department's proposals.

A. The Capital Investment Project proposal represents an important step in the right direction, and requires clarification and careful design.

The Capital Investment Project ("CIP") proposal is an important step toward enabling greater penetration of DER in support of Massachusetts' climate and clean energy goals. If designed appropriately, the CIP framework has the potential to reduce interconnection costs for DER customers and developers. In order to ensure the CIP planning and investment process is effective at supporting cost-effective DER interconnection and balancing fairly between facility and ratepayer cost recovery, the Department, working with stakeholders, must develop answers to several critical issues. As further explained below, the issues include but are not limited to: (1) Will the CIP Fee be optimally designed to minimize the cost barriers to interconnection?; (2) Will the CIP planning process and resulting Fee include any investments that the EDCs would have had to undertake as part of regular grid operation and maintenance?; (3) How will the EDCs' CIP costs be treated for purposes of revenue recovery?

We address each of these questions in turn below.

1. Identifying CIP Upgrades and Determining Cost Responsibility

(a) The planning process must be designed to optimally support DER integration and Massachusetts' climate and clean energy goals.

IREC strongly supports the development of a distribution system planning and assessment process that proactively plans for forecasted load growth and DER integration in support of Massachusetts' climate and energy goals. In order to achieve the intent of the

Department's proposed planning process, the planning methodology and criteria must be designed to identify and support DER integration and Massachusetts' energy goals, including electrification. To the extent that the Straw Proposal's planning process is separate from and additional to the EDCs' traditional distribution forecasting and investment planning processes, it must be designed to exclude capital investments that the EDCs would have made in the regular course of business of maintaining and operating the distribution grid in service of their customers.[2] In addition, the planning process must be designed to forecast with as much accuracy as possible the projected load growth and facility interconnection—the planning process must not overestimate the amount of required capacity upgrades. Finally, the planning process should identify and exclude capital investments that would result in minimal or nominal capacity upgrades.

If the planning and assessment process were to capture investments that go beyond what is necessary to enable the capacity required for future DER integration, that could lead to a number of negative outcomes for interconnection customers and ratepayers. First, it could lead to larger amounts of unsubscribed capacity, which ratepayers would have to pay for. Second, there would be a greater chance that the resulting CIP Fee would be higher than the market can bear. Third, if EDCs were to include capital investments that would otherwise be necessary for the regular maintenance and operation of the grid, that could result in an inequitable allocation of costs between interconnection customers and other ratepayers, with interconnection customers paying for upgrades that are not specifically necessary for the interconnection of DERs.

[2] However, we generally recommend a more holistic approach to integrated distribution system planning that does not silo the traditional grid management forecasting and planning process from proactive DER integration planning.

Put simply, the planning and assessment process must be designed in such a way as to support cost-effective and efficient CIP Fees that effectively address one of the principal barriers to interconnection: high grid upgrade fees; and it must exclude from project development and cost recovery any projects that would result in minimal or nominal capacity increases for interconnecting DERs.

In designing the distribution system planning and assessment process, the Department, working with stakeholders, must develop a mechanism for demonstrating that proposed CIP projects meet the above criteria, as well as the other criteria that will be included as part of the assessment process. A number of factors can impact DER growth forecasts, including, but not limited to, "data regarding utility DG procurement programs, the typical size of generating facilities that have sought interconnection, project success rates within those programs, PV pricing trends, and federal, state and local policy activity," as well as "anticipated changes in load profiles, demand response programs and energy efficiency installations."[3]

In addition, the distribution system assessment should identify projects that provide broader benefits, beyond enabling incremental DER capacity, such as: (1) societal benefits related to greenhouse gas emissions reductions, to the extent such benefits are not already accounted for through rates; and (2) the benefit capacity upgrades may provide in supporting Massachusetts' electrification of buildings and transportation.[4]

[3] Integrated Distribution Planning Concept Paper at 10.

[4] MA Dept. Pub. Utils., Dkt. 20-75, Vote and Order Opening Investigation ("Order"), Att. A ("Straw Proposal") at 13 (Question 1(c)) (Oct. 22, 2020).

(b) Ratepayers will benefit from CIPs, and thus it is reasonable to allocate a portion of subscribed capacity fees to ratepayers.

As mentioned above, CIPs will almost certainly have benefits for utility customers beyond the ability of interconnection customers to interconnect due to expanded grid capacity. Ratepaying customers will enjoy the benefits of a more modern and expansive grid infrastructure, such as capacity upgrades that anticipate and accommodate future load growth from electrification and upgrades that provide safety and reliability benefits but that may not have been justifiable without interconnection customer investment. Further—and perhaps most importantly—all ratepayers will benefit from expanded infrastructure to accommodate DERs because expanded DER capacity achieves the Commonwealth's clean energy goals and helps to avoid the worst impacts of climate change.

Because ratepayers will benefit from the CIP program, IREC supports allocating some of the CIP Fee to ratepayers. We recommend that the calculation of how much of the fee to allocate to ratepayers consider factors like whether upgrades would have happened anyway to accommodate future load growth and a reasonable allocation of the fee to account for societal benefits of expanded DER. Further, as discussed in the following section, allocating some of the CIP Fee to ratepayers may allow grid upgrades to accommodate DERs that would not have been able to shoulder the financial burden alone. Far from indicating that those projects would have otherwise been uneconomic, including ratepayer investment in costly upgrades recognizes that clean energy benefits far more people than the developer alone. In addition, it could provide a critical benefit in the event CIPs are higher than the market can bear, as described in the following section.

(c) The Department should consider what to do when CIPs necessary to support more solar cost more than the market can bear.

As noted above, high upgrade fees have represented a significant barrier to DER deployment, which the Department's proposal is intended to address. Even with the distribution planning and assessment process, it is possible that the process may identify necessary upgrades that are simply more than the market can bear. For example, as mentioned above, upgrade costs could exceed what proposed DERs could afford, even when projects share costs and when some of the CIP Fee is allocated to ratepayers based on the expected benefits they will receive.

In such a case, the CIP program may fail to achieve its desired effect, resulting in continued barriers to DER deployment, as well as a greater likelihood of unsubscribed capacity—a "lose-lose" situation for DER integration, the Commonwealth's climate and energy goals, and ratepayers. If unsubscribed capacity were to reach 1.5% of the EDCs' total revenue recorded during the calendar year, that could result in potentially substantial sums being charged to ratepayers for unsubscribed capacity that fails to result in DER projects and fails to provide system or societal benefits to justify the cost.

The Department could mitigate this risk by permitting EDCs to allocate a portion of subscribed capacity fees to ratepayers as needed to allow continued DER growth, as described in the preceding section. This would provide some assurance that if the CIP Fee were higher than the market can bear, DER integration would not be stymied. The degree of costs allocated to ratepayers can be reviewed and adjusted periodically to ensure it is calibrated to provide only necessary support, without charging ratepayers unnecessarily.

2. The revenue recovery mechanism must support economic and operational efficiency.

Historically, upgrades necessary to accommodate proposed DER projects were paid for by interconnection customers and were treated as a pass-through—the utility did not rate base the capital investments. Here, the proposal appears to include the opportunity for EDCs to include CIP costs in rate base. It is unclear whether the Department proposes to rate-base *all* of the CIP costs, or just the costs associated with the unsubscribed capacity, which ratepayers would bear (and not the costs interconnection customers would pay for their respective capacity subscriptions).

The revenue recovery mechanism is particularly important because the planning process could result in an overestimation of the level of capacity upgrades necessary to support forecasted load growth and DG integration, which could lead to unsubscribed capacity; the rate basing of investments that provide no tangible system, ratepayer, or societal benefit; and potentially a significant boon for shareholders. In short, the potential for the CIP planning process to overestimate the necessary capacity upgrades, combined with the capex bias inherent in the revenue requirement formula, could lead to overinvestment that is not in the public interest and does not support just and reasonable rates.

IREC recommends that, at a minimum, the Department clarify that the individual interconnection customers' capacity subscription costs would be treated as traditional grid upgrade fees paid by DER projects—i.e., as a pass-through—regardless of whether the proposed capacity upgrade is identified through the distribution planning and assessment process or through individual facility interconnection requests. EDCs should not rate base the *subscribed* capacity, and interconnection customers should not be required to pay, as part of their shares, costs associated with recovering the EDCs' rates of return. We also recommend not rate basing the remaining life of assets that are upgraded.[5]

In addition, to the extent EDCs are permitted to include in rate base *any* portion of the CIP costs, the Department must ensure economic and operational efficiency in the public interest, while providing EDCs a fair return on investment. Regardless of whether the capacity is subscribed or unsubscribed, if a particular CIP is approved for cost recovery, the EDCs appear to essentially be guaranteed recovery from developers or from ratepayers. The CIP program, including the distribution planning process, capacity project investments, and cost allocation, must not be viewed in isolation, and must be considered in the broader context of the EDCs' rate plans and rate of return (and particularly return on equity) proposals, to evaluate the balance between return and risk and ensure the EDCs' investments align with principles of economic and operational efficiency and Massachusetts' clean energy and climate goals.

B. Small projects should be exempt from the CIP Fee and pay only a small fixed fee to cover all potential upgrades.

Finally, Simplified Process projects should be exempt from paying a proportional share of the CIP Fee for a number of reasons. First, small projects are less likely to be able to bear significant upgrade costs, and there is a chance that even a pro rata share of some very expensive CIP upgrades could render a small project financially infeasible. Further, smaller projects individually contribute very little to the need for upgrades and so exempting them from the fee apportionment will not unfairly burden other customers. Instead, a set fee for Simplified Process projects would ensure equal access to solar for all small customers. It does not further the

[5] Response to Question 1 under section (I)(b)(viii) in the *Summary of Department Staff Responses to Stakeholder Questions*, issued November 20, 2020.

Commonwealth's clean energy goals and fair treatment of residential and small commercial customers if a customer in one neighborhood pays no upgrade fee to interconnect, while a customer in a neighborhood across town pays thousands. These factors weigh in favor of establishing a set fee for small projects—and thereby providing cost certainty, predictability, and fair access to renewables—and outweigh any benefit of trying to calculate project-specific fees for the large volume of the smallest projects.

Second, the administrative burden added to EDCs to calculate the CIP Fee for the smallest projects would not be justified by the minor benefit of having those projects contribute to the CIP costs. The EDCs receive a very high volume of simplified process applications,[6] and having to calculate the applicable fee for each application, depending on its impact on specific CIP upgrades, would add considerably to the EDCs' cumulative administrative burden.

For these reasons, instead of charging Simplified Process projects a calculated share of CIP upgrade costs, these projects should pay a single, flat upgrade fee intended to cover the project's impact on all upgrades, including CIPs and Common System Modifications, as discussed below.

C. The Department should ensure that there is an effective stakeholder process for approving distribution upgrade plans and capital improvements.

As the Department recognized in the Order and in its request for comments on the Straw Proposal, it is important to develop a stakeholder process for development and approval of a ten-year distribution assessment. We cannot overemphasize the importance of such a process to ensuring that the CIPs proposed are the most effective and efficient for achieving the

[6] According to responses to information requests filed by the EDCs in this docket on December 4, 2020, National Grid received 9,010 Simplified Process applications in 2020 and Eversource received 5,807.

Commonwealth's clean energy mandates and ensuring cost-effective interconnection of new DERs. The Department has indicated that the EDCs should provide proposals on this stakeholder process in their opening comments, and IREC looks forward to providing feedback on those proposals and providing further comments on reply.

III. A Single Fee for Simplified Process

Simplified Process projects that may export should be able to interconnect by simply paying a single, standardized upgrade fee that would offset small projects' incremental contribution to the need for future upgrades or impact on recent upgrades. This fee should encompass CIP and Common System Modification upgrades, and no fee should be charged to non-exporting projects, which have no or virtually no impact on the need for upgrades.

The key consideration in establishing a fee for the smallest DER projects, which apply under the Simplified Process track, is ensuring that the fee accounts for the projects' reasonable impacts to the grid without being so high as to render projects unviable. Cost allocation is perhaps most important for these small projects, which generally do not trigger upgrades but often cannot afford upgrade costs if they are unlucky and end up the trigger of upgrades behind larger projects. Notably, these small projects are typically intended to allow customers to offset their own energy use, so they have no option to shift the project to another site where upgrades may not be necessary. All of these considerations support a fixed upgrade fee as the fairest approach for Simplified Process projects and the most likely path to achieving the Commonwealth's clean energy goals.

The easiest way to share upgrade costs with Simplified Process projects is to annually establish a set fee that all such projects pay to contribute to all upgrades, including CIPs, Common System Modifications, or project-triggered upgrades that would typically be paid by the cost-causer. A simple way to set a per-project fee is to divide the previous year's upgrade costs attributable to or consumed by Simplified Process projects by the number of such projects in that year. Then, that (likely low) fee would be charged to each approved project in the following year. If the costs are much higher and there is a shortfall at the end of the year, the costs could be attributed to the rate base or the following year's fee could be adjusted. Using previous years' numbers to establish the fee for the following year avoids unnecessary administrative burdens on the EDCs. Essentially, the fee would be an estimate of the coming years' projects' impacts and would be adjusted annually to ensure there is little or no over- or underpayment by small projects as a whole. California currently uses a similar approach for charging a single fee to NEM projects to cover all of the utilities' administrative and engineering costs for NEM projects.[7]

We anticipate the upgrade fee for small projects would be low. In California, utilities report on upgrade costs attributable to NEM applications below 1 MW (which are up to forty times larger than Simplified Process projects in Massachusetts).[8] The most recently submitted reports indicated that the per-project cost of distribution upgrades that were necessary to accommodate the interconnected DERs in California were as low as $1.10 per project in San Diego Gas & Electric's territory, to up to $89.75 per project in Southern California Edison's

[7] California Public Utilities Commission, D. 16-01-044, Decision Adopting Successor to Net Energy Metering Tariff, at 87-88 (January 28, 2016), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf.

[8] Note that California currently waives all upgrade costs for NEM projects under 1 MW, and those costs are borne by ratepayers.

territory and $187.83 per project in Pacific Gas & Electric's territory.[9] It is notable that the per-project cost reported by California utilities remains low, even though it includes upgrades for projects all the way up to 1 MW in size.

Data recently provided by the EDCs in this docket similarly indicates low average upgrade costs for simplified projects: National Grid reported 9,010 Simplified Process applications in 2020 and total of $749,288 in upgrades to accommodate these projects—the equivalent of $83 per project.[10] It should be noted that these costs reflect *triggered* upgrades, not proportional share, and small projects' actual contribution to the need for upgrades is likely lower. While existing cost information indicates that costs likely will be reasonable using this approach, the Department should nonetheless ensure that costs charged to Simplified Process projects are reasonable for such projects to bear and effectuate the Commonwealth's clean energy mandates. We recommend that if the Department adopts this policy, it tracks costs over a few years to ensure they remain reasonable for Simplified Process projects.

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[9] San Diego Gas & Electric Co, Advice Letter 3601-E, Information Only Filing Regarding Net Energy Metering (NEM) Costs (Sept. 1, 2020), *available at* http://regarchive.sdge.com/tm2/pdf/3601-E.pdf; Southern California Edison, Advice Letter 4296-E, Information-Only Advice Letter, Southern California Edison Co.'s Report on Net Energy Metering Interconnection Costs (Sept. 21, 2020), *available at* https://library.sce.com/content/dam/sce-doclib/public/regulatory/filings/pending/electric/ELECTRIC_4296-E.pdf; Pacific Gas & Electric, Advice Letter 5964-E, Information-Only Filing Regarding Net Energy Metering (NEM) Costs (Sept. 29, 2020), *available at* https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5964-E.pdf.

[10] Eversource did not provide information that helped calculate per-project upgrade costs. This information will be necessary to establish the fee.

IV. Common System Modification Fees

The staff proposal also asks whether other systems of cost allocation should be considered in addition to the CIP fee and the existing cost-allocation mechanisms including billing the cost-causer and group studies. It is reasonable to provide for cost sharing for Common System Modifications[11] where upgrade costs—especially significant upgrade costs—are not covered by a CIP. This would ensure that there is a reasonable cost allocation option available where a significant upgrade that was not planned for in the distribution planning process is needed to accommodate proposed DER projects.

Again, we recommend that allocation of costs for Common System Modifications should be used only for larger projects under the Expedited or Standard Process. The smallest, Simplified Process projects should be subject to the single fixed upgrade fee, as explained above. For projects seeking to interconnect through the Expedited or Standard Processes, the Straw Proposal suggests three options: (1) a minimum upgrade fee paid regardless of whether an upgrade is triggered, which would be used to defray costs for projects triggering future upgrades; (2) a fixed, per-kW fee paid to cover future upgrades, with the remainder charged to ratepayers; or (3) a cost ceiling, with the remainder charged to ratepayers.[12]

Of these three options, we recommend the fixed-fee-per-kW approach to Common System Modifications. This approach has the benefit of providing cost-certainty to projects, while also making costs proportional to impact. While the fee should be set with the goal of

[11] A "Common System Modification" is a "change[] made to a Distribution Company's EPS that benefit[s] more than one interconnecting Facility or distribution customers at large." Straw Proposal at 1.

[12] Straw Proposal at 11-12.

covering most upgrade costs (without going over), it is reasonable for ratepayers to share in some of the cost of Common System Modifications, which will generally provide benefits for all customers, including the benefit of increased access to renewable energy. We agree that one drawback is that a single per-kW fixed fee would not provide cost signals regarding facility location. This could be addressed by having a small range of fixed Common System Modification fees, where projects proposed in areas identified as likely to need more significant upgrades in the near future would pay a higher fee.

One issue of concern with geographic-specific fees is that calculating this fee is likely to be complicated if attempting to project future Common System Modifications. Because this fee would be only for Common System Modifications, and not for CIPs, which are subject to another fee, estimates may fail to include the right projected projects, and proposed DER could end up double-charged. A better way would be to use the same approach as proposed above for simplified projects: use the previous year's Common System Modifications and number of projects to establish a fee for the next year's applications. If the EDC recovers more in fees than is spent in a given year, that amount should be either refunded on a per-kW to projects that paid the fee, or used to reduce the future years' fees.

We recommend that the fee be charged based on export capacity and not nameplate capacity to the extent that a project's export capacity is relevant to its impact on or contribution to need for the upgrade. For example, export capacity determines a project's impact on voltage or thermal impacts, while the full nameplate contributes to certain types of protection upgrades (i.e. fault current) and thus allocation by nameplate capacity is appropriate. Only those upgrades where nameplate capacity is relevant to determining impact should be charged based on nameplate.

Finally, we recommend that the Common System Modification fee apply both to individually studied projects and projects in a group study. Adoption of the CIP and a Common System Modification fee would likely result in a waning need for group studies (unless they are needed to process studies expediently). But where projects are still studied as part of a group, they should have the benefit of participating in the Common System Modification fee program, while sharing any additional upgrade costs among the group. This ensures that projects in group studies do not end up paying a higher share of fees than individually studied projects would.

V. Short-Term Proposals

IREC agrees that short-term approaches may be necessary to achieve fair allocation of costs while the programs discussed above are implemented. We generally support the Attorney General's proposal to use dynamic curtailment and power control programs in the short term to allow a project to interconnect without triggering cost-prohibitive upgrades, either by agreeing to limit its export capacity or by consenting to allow the EDC to curtain output when necessary.[13] Indeed, we have actively been advocating for the necessary policy changes to the interconnection process that would actually allow projects to limit their export capacity or propose limited curtailment based upon identified impacts for over a year now and encourage the Department to move ahead with those changes.

However, we agree with the Attorney General that these proposals do not address the issue of what happens when an upgrade is the only way to allow more projects to interconnect. To ensure that there is a system in place that facilitates even expensive upgrades to allow DER interconnections in the meantime, the Department should consider whether interim approaches

[13] *See generally* Order, Att. B-1.

are required to manage costs of necessary construction while the distribution planning process discussed above is implemented. The Commonwealth's current group study program may be sufficient to adequately share costs, but the Department should also consider whether a reimbursement program, like that proposed by the Attorney General,[14] would also be useful, especially in cases where only a single project is currently proposing to interconnect, but more projects are likely in the future.

The cost-reimbursement option would require the cost-causer to pay an upgrade cost, then require future projects that interconnect and gain the benefit of the upgrade within a certain period of time to reimburse the first project a portion of the cost. This ensures that there is adequate cost-signaling to proposed projects regarding location and that projects generally pay only for the upgrades they are actually using. New York has adopted this approach for some projects. Under New York's system, a solar DER project between 25 kW and 2 MW that triggers certain upgrades first pays the full upgrade cost.[15] However, the next project to interconnect and use that upgrade within a limited time period splits the cost with the first project, based on project size, and reimburses the first project. If a third project joins the circuit within the prescribed time period and uses capacity made possible by the upgrade, that project contributes reimbursing the first two, and so on.

[14] *See* Order, Att. B-1 at 11-15.

[15] *See* NY Pub. Service Comm., Standardized Interconnection Requirements and Application Process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems, Appendix E: Cost Sharing for System Modifications & Cost Responsibility for Dedicated Transformer(s) and Other Safety Equipment for Net Metered Customers (Dec. 2019) ("NY SIR"), Appx. E, *available at* https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/December%202019%20SIR%20-%20FINAL%20-%20Clean.pdf.

This approach to cost-sharing ensures that a single project is not responsible for shouldering all of the costs of a Common System Modification when that upgrade enables the development of other DERs in the near future. Customers may be more likely to agree to expensive upgrades with the knowledge that they are likely to be reimbursed for some of these costs in the future. However, this approach may not be feasible if the cost-causer does not have the capital available to cover the initial cost. Also, depending on the location of the project, other projects may not come along to provide reimbursement, which introduces uncertainty for applicants. This approach does add an administrative burden to the EDC, which must monitor whether new projects enjoy the benefits of upgrades and calculate reimbursement to the original paying project.[16] We also think the reimbursement proposal proposed by Eversource—whereby the EDC pays for the upgrade when it is triggered, and recovers proportional costs from interconnecting projects—is another reasonable option for sharing upgrade costs while more long-term proposals are implemented.[17]

Overall, the reimbursement approach is likely to have higher administrative burdens and there is a higher likelihood that projects would still be stymied by inability to pay for the upgrades up front. Thus, we emphasize that it is better suited to use in the short term and not as a long-term cost allocation solution.

[16] This impact-based allocation is in contrast to the approach frequently taken at the transmission level, where the project is paid back for upgrades over a period of time by the transmission provider regardless of future projects or their proportional impacts.

[17] Order, Att. B-3 at 18-19.

VI. Conclusion

IREC appreciates the opportunity to provide these comments. As discussed above, the Department's efforts to allocate costs more fairly will have a significant positive benefit for the Commonwealth's goal of expanding access to clean energy. The key factors to a successful program will be to ensure that costs are allocated fairly without overburdening the smallest projects, that ratepayers pay their fair share to the extent they benefit from upgrades, that the EDCs are not overburdened by the administrative tasks necessary to support cost allocation programs, and that any return EDCs enjoy on upgrades are reasonable and fair. Once such a program is established, like with its distribution group study program, Massachusetts will again be leading the nation in facilitating interconnection of clean energy generation.

[signatures on next page]

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