REPORT ON INTERCONNECTION REQUIREMENTS FOR THE SOLAR PV INDUSTRY IN THE NORTHEAST U.S.

A REVIEW OF VARIOUS REQUIREMENTS BY ELECTRIC DISTRIBUTION COMPANIES
IN NEW ENGLAND AND NEW YORK

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1. INTRODUCTION

“Renewable energy” is defined in various ways and the term is used by electric industry participants, politicians, investors and speculators and consumers depending on the context and goals looking to be achieved by the user of the term. Regardless of the context in which the term is being used, solar energy, and in particular the production of electricity from solar panels (known as “photovoltaics”), has emerged as one of the most recognized renewable energy sources for both commercial and residential customer-side installations. As an industry, a large number (majority) of residential and small scale solar installations are performed by local contractors or regional contractors that participate in the solar market. The contractors operate across a number of States within their region and within a number of territories controlled by different Electric Distribution Companies (known as “EDCs”) often within the same State. At the same time, larger national companies deploy significant marketing efforts for the sale of residential and small commercial projects in regional and state markets but often employ these same local or regional contractors to install projects. Thus, it is the small local and regional contractors that must comply with the various interconnection requirements of the EDCs.

EDCs control the electric distribution grid within their territory. Most commonly, EDCs are limited to transmission and distribution of electricity to customers. Depending on the State and regulatory restrictions, the EDCs transmit and distribute electricity that they generate or that is generated by third parties. In addition, EDCs operate, maintain and repair the electric transmission and distribution grid. EDCs also interconnect the distribution (and sometimes transmission) network to renewable energy projects, including photovoltaic projects, that are located throughout their territory (this is known as “Distributed Generation”) and which are typically several factors smaller in size than traditional large centralized generation facilities. Through State statutory and regulatory requirements, many of the activities conducted by the EDCs are overseen and approved by State regulators which go by various acronyms (PSC, PURA, DOER, PUC).

Regardless of State or territory, common to each of the EDCs is the requirement that photovoltaic projects must interconnect to the electric distribution grid at a location proximate to the project to participate in the Net Metering program defined in each state. Only rarely do residential or small commercial photovoltaic projects not take advantage of the Net Metering program. Net Metering allows a property owner (or the account owner at the property) to off-set their energy use with the electricity generated by the photovoltaic project. Net Metering requires that the electricity generated by a photovoltaic project flow to the electric distribution grid. The EDC then credits (or deducts from the electric usage) the account owner for the electricity generated by the photovoltaic project. The amount of credits available in a Net Metering program varies from State to State and even from EDC territory to EDC territory. However, a common requirement for virtually all small commercial and residential photovoltaic installations is an interconnection to the electric distribution grid.

While the requirement for interconnection is common across jurisdictional boundaries and utility company territories, the method and manner of interconnection varies by both state boundaries and utility boundaries. And, solar installers report that they find varying requirements between different subsidiaries of the same utility company.

These variations in the interconnection requirements of various utilities in a relatively small region like the Northeast seem to increase costs to consumers like no other region in the United States. Solar installers must vary their design and installation protocols thereby prohibiting a common design that is able to be repetitively used on a large customer base. By maintaining these different interconnection requirements, electric distribution companies create expensive barriers to installations. By comparing interconnection requirements across States and EDC territories, we are able to identify interconnection requirements that (1) are best practices and should be adopted by all EDCs; (2) may be not necessary and should be eliminated by all EDCs or (3) may be subject to compromise between the EDCs and the photovoltaic industry.

2. Methodology

In order to gain a broad range of information, we consulted with developers that operate across the Northeast and selected nine EDCs with large customer bases in the territories represented by the Northeast Solar Coalition.

- Eversource (Connecticut)
- Central Maine Power Co (Maine)
- Eversource/NSTAR (Massachusetts)
- National Grid (Massachusetts)
- Eversource (New Hampshire)
- PSEG (NewJersey)
- National Grid (New York)
- Consolidated Edison (New York)
- PECO (Pennsylvania)
- National Grid (Rhode Island)
- Green Mountain Power (Vermont)

Recommendations from developers working with the Northeast Solar Coalition also weighed heavilty on the selection of five technical standards to review.

- Direct transfer trip
- Power factor requirements
- Reverse power flow
- Remote control and monitoring requirements
- DG capacity feeder limits

For each EDC, we reviewed publicly available interconnection guidance documents when available and identified relevant information regarding the technical standards in each of the documents. Based on this review, we assessed the transparency and clarity of the information provided by each company to compare the ease of accessing information from the EDCs. We also compared and contrasted guidance provided by the utilities for each of the five technical standards. Since many of the guidance documents either did not provide sufficient information to determine the technical standard or the technical standards were not clearly defined, we convened stakeholder groups to review the data and discuss experiences with the technical standards. We also utilized the stakeholder group to understand the technical requirements beyond the EDCs documentary guidance.

Based on this procedure, we developed findings for EDCs across the northeast relating to the transparency of the standards. We also developed recommended action items that can and should be undertaken in the various northeast jurisdictions to develop a more transparent and consistent interconnection process.

3. Results

a. Transparency and Cost Issues

We had assumed that many of the data points for this Report would be available on the EDCs websites in a manner that would be accessible by installers. As we discovered through this process, one of the first inconsistencies between and among the various EDCs is the variation in the interconnection guidance documents, the availability and accessibility of documents, format of the documents and content of the documents.

According to the stakeholder group, an important piece of information that is missing from all EDC websites is the availability of mapping information relating to circuit feeder capacity. This information includes the amount of distributed generation already existing on the circuit feeder, the amount of load that the EDC may want on the circuit feeder, the voltage of the feeder and other pending distributed generation projects for that circuit feeder. This information is important for an installer early on in the sales/development cycle. This circuit feeder information provides the installer critical information relating to (1) whether significant upgrades and construction is required to accommodate the project being contemplated; (2) whether a reduction in project size will significantly impact the interconnection costs; (3) the need for additional generation on a circuit to resolve distribution issues being experienced by the EDC; (4) the impact of other projects and (5) the ability of different developers to work cooperatively.

While no EDC offers this information, New York through its Standardized Interconnection Requirements (known as the New York SIR) contains a good first step in this process. Under the New York SIR, photovoltaic installers can request circuit feeder information with the payment of a $750 fee, which is applied to the ultimate interconnection application fee if the project moves forward. The New York SIR also has very clear guidelines on timeliness.

While the New York SIR is a step in the right direction, the ultimate beneficial tool for distributed generation would be to have web-based access to the circuit feeder information. A concern recognized by the stakeholder group for EDCs is network security. EDCs view publicity relating to circuit feeder information as a grid security and reliability issue. Nonetheless, the stakeholder group believes that with proper security protocols and background checks of authorized users, the information relating to circuit feeders can and should be made available to installers on a real-time basis.

While New York offers the pre-application process for circuit feeder information, the stakeholder group recognized Massachusetts as having the industry best pre-application process. While the information supplied by New York is critical, the amount of information given in Massachusetts is greater even though it may not contain the same information as New York.

In addition to the pre-application process, no state currently allows for cost-sharing of upgrades for small commercial and residential projects. As noted above, interconnection of distributed generation projects to the electric distribution grid often requires upgrades and construction to the electric distribution grid before interconnection can occur. When upgrades occur to a circuit, the upgrades often allow not only the current project to interconnect to the electric distribution grid but also provide the capacity for future projects to interconnect to the same circuit feeder. Under the current guidelines, the project that initially causes the upgrade pays the entire cost of the upgrade while all subsequent projects do not contribute to that cost. The stakeholder group believed that having a mechanism to share the cost of upgrades that benefit future projects would significantly assist in development of distributed generation.

Cost sharing and cost recovery is already a part of utility cost structure. The water industry has instituted cost sharing for development projects which has allowed residential developers to recoup water main and other infrastructure improvements that benefit individual users that tap into the infrastructure improvement. These agreements are known as Contributory Plans. A similar plan can and should be developed for upgrades to the distribution grid.

b. Technical standards

In addition to the transparency of information available from the EDCs and the need to address the costs of interconnection that benefit more than the latest project causing the upgrade, there are a number of technical standards imposed by the EDCs which are inconsistent among the various EDCs and/or not necessary. In conjunction with the stakeholder group, we reviewed a number of these technical standards and include our findings herein.

i. Capacity Feeder Limits

Circuit feeder capacity limits is the amount of power that can be placed on a particular circuit feeder by a distributed generation system before the circuit feeder reaches a certain capacity assigned by the EDC. Once a circuit feeder reaches capacity, upgrades are required to allow additional distributed generation to interconnect to the circuit feeder. As discussed above, the stakeholder group viewed information relating the circuit feeder as a crucial piece of data in determining the feasibility of a Project. Ideally, this information can be made available to developers through a secure web portal to developers without interference from or interaction with the EDCs. Beyond making the current circuit feeder information available to developers, EDCs place limits on the amount of photovoltaic capacity that can be placed on a circuit feeder. These limits in many cases appear arbitrary. As such, developers have uncertainty about whether a circuit feeder is close to capacity even if the current capacity of the circuit feeder is provided to the developer. A developer may not know the capacity placed by the EDC on a circuit feeder until after a request for interconnection is made to the EDC.

EDCs place caps on circuit feeder capacity either in specific amounts or in percentages. The EDCs do not share how these caps are determined and the caps are not specifically regulated by the utility commissions. For developers, EDCs should adhere to standardized formulas for the caps being placed on circuit feeders. The formula will allow a developer to understand how the cap was developed and the process for determining whether a circuit feeder has reached a cap. This transparency will lower the amount of arbitrary caps currently being placed on the circuit feeders. The current practices in California, New York and Massachusetts are a step in the right direction but more can be done to standardize the cap amounts and share that information with developers.

Overall, developers need information from EDCs to determine whether a circuit feeder is at/near capacity, developers need to know how the EDC determines whether a circuit feeder is at/near capacity and how the utility arrived at the process of determining feeder capacity (i.e. is it arbitrary or not?). As of now, the best practices are the Massachusetts pre-application reports. At the same time, California and New York are trying to develop data maps with circuit feeder information. While these are current best practices, more can and should be accomplished to provide developers with circuit feeder information.

ii. Reverse power flow

Reverse power flow is the ability of a distributed generation system to send power on to the distribution grid flowing back towards the substation (i.e., in reverse flow from the power coming from the substation). The amount of reverse power flow allowed on a circuit feeder is synonymous with the circuit feeder capacity discussed above. Beyond the circuit feeder capacity issue, the stakeholder group identified the ability to flow reverse power not only through the circuit feeder but also through the substation (where the circuit feeder originates) to another circuit feeder originating at the substation.

The ability to flow power through the substation to other circuit feeders increases the capacity of the individual circuit feeder and allows the power flow impact to be viewed at the substation level instead of at the individual circuit feeder level.

To accomplish reverse power flow through the substation, the EDCs analyze the effect of the distributed generation on the substation as a whole and not on individual circuit feeders. If reverse power flow through the substation is required (because the direct circuit feeder capacity has been reached), additional equipment may be required at the substation. Even though developers will be required to pay for this upgrade (which will benefit other developer and thus should be subject to cost sharing), developers should be given this option to have a project proceed forward.

Throughout New England, the ability to reverse power flow through the substation is inconsistent. While Massachusetts and New York are addressing the issue of reverse power flow through the substation, other New England jurisdictions have yet to do so. A consistent approach to reverse power flow is warranted to continue with the growth of distributed generation projects.

iii. Anti-islanding protections

Anti-islanding (which should really be called just Islanding) is the requirement for a distributed generation project to stop flowing power on to the circuit feeder during an emergency (and thus become an Island). Traditionally, EDCs have required that all projects install a Direct Transfer Trip or "DTT". DTTs allow the EDC to Island a project automatically through a pre-determined protocol of substation relays or manually. DTT is an expensive installation for a developer and is often not the best solution for anti-islanding protection. DTT requires not only equipment but also a dedicated telephone line to the substation which adds substantial costs which continue to rise. As the stakeholder group expressed, DTT has become a "one-size fits all" solution for EDCs to protect the electric distribution system from distributed generation systems. Stakeholders view DTT as the "sledgehammer solution for all problems" used by the EDC. Instead of a blanket DTT requirement, EDCs should utilize screens that evaluate whether DTT is the best solution in a given situation. Further, EDCs should take into account that modern inverters have anti-islanding protections integrated into the hardware which is installed at the project site.

One solution that some New York and Massachusetts EDCs have implemented is to require that developers bear all risk of loss if DTT is not installed. This solution seems to be satisfactory to the stakeholder group. Interestingly, a draft report of the New York joint utilities found that anti-islanding risk is insignificant and that EDCs should find lower cost alternatives to DTT.

iv. Other Issues Reviewed

Beyond the issues addressed in this Report, we also reviewed Remote Control and Monitoring requirements for photovoltaic projects. However, the stakeholder group did not view this issue as currently important for residential and small commercial projects. Based on current inverter technologies, this issue is not critical to developers. As inverter technologies advance, Remote Control and Monitoring will be become more important. Our review of current interconnection guidelines in the Northeast, telemetry equipment is required in projects that exceed 500 kW or 1 MW. These systems sizes do not include residential and small commercial installations.

We also evaluated power factor requirements. Power factor relates the amount of instability that a generating device has on the electric distribution system. A power factor of 1 indicates that the generating device has no instability affect. Most EDCs require photovoltaic systems to have a power factor of +/- 0.9. The EDCs use this requirement to protect against power surges on the electric distribution system. Because modern inverters are rated for this level of power factor, the power factor required by EDCs is not a central issue to the stakeholders at this time.

4. Conclusion / Recommendations

Our review of interconnection guidelines in New England demonstrated that EDCs in some New England states are implementing best practices with the collaboration of photovoltaic system developers. These working groups have been instrumental in developing the Massachusetts pre-application program which has significantly helped developers understand and anticipate upgrade costs and the viability of projects. The stakeholder group strongly urged the expansion of these working groups in New England and the sharing of results across jurisdictional boundaries.

Beyond working groups, we recommend that the photovoltaic industry continue to work towards greater accessibility and transparency relating to circuit feeder capacity and installation costs. While some strides have been made in this area, no EDC has implemented a web-based system available for developers. Once costs are determined, the industry should petition the various state regulatory bodies to implement a cost-sharing mechanism similar to the water industry's Contributory Plan. System upgrades required by EDCs for the installation of distributed generation system help the current project requiring the upgrades but also assist all future systems on that circuit feeder or substation area. As such, these upgrade costs should be shared by developers.

In addition, technical requirements imposed by the EDCs relating to reverse power flow and anti-islanding remain antiquated and require improvement. EDCs have been slow to allow reverse power flow through the substation even though equipment is available to allow it. While reverse power flow may require system upgrades payable by the developer, the developer should be given the option to incur such costs. Similarly, EDCs continue to require DTT as the sole means to protect against anti-islanding concerns. DTT has been shown to be a response to a problem that requires less draconian methods to resolve. The EDCs in New York have agreed that DTT is not always an appropriate response to anti-islanding issues and given the modern inverter technology, DTT is no longer the first or only option available for anti-islanding.

The photovoltaic industry should continue to engage with the EDCs when appropriate to develop best practices and lower barriers to the continued development of photovoltaic systems. At the same time, the industry should be requesting appropriate regulatory agencies to implement these best practices across jurisdictional boundaries. Harmonizing the interconnection process and requirements among the various jurisdictions will increase the ability of photovoltaic system developers to efficiently design and install projects. At the same time, consumers will enjoy lower costs for energy.

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