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August 1, 2022

VIA ELECTRONIC FILING

The Honorable Bernard Logan, Clerk
Virginia State Corporation Commission
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Tyler Building, First Floor
1300 East Main Street
Richmond, VA 23219

RE: ***Ex Parte*: In the Matter of Considering Utility Distributed Energy Resource Interconnection-Related Issues and Questions Case No. PUR-2022-00073**

Dear Mr. Logan:

Enclosed for filing in the above-referenced proceeding, please find the Comments of the Chesapeake Solar & Storage Association and the Coalition for Community Solar Access.

Please feel free to contact me should you have any questions.

Sincerely,

Eric J. Wallace

Enclosure
cc: Service List

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

Ex Parte: In the Matter of Considering Utility	)	
Distributed Energy Resource Interconnection-	)	PUR-2022-00073
Related Issues and Questions	)	

COMMENTS
OF THE CHESAPEAKE SOLAR & STORAGE ASSOCIATION
AND THE COALITION FOR COMMUNITY SOLAR ACCESS

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August 1, 2022

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COMMENTS
OF THE CHESAPEAKE SOLAR & STORAGE ASSOCIATION
AND THE COALITION FOR COMMUNITY SOLAR ACCESS

The Chesapeake Solar & Storage Association (or "CHESSA") and the Coalition for Community Solar Access (or "CCSA") appreciate the opportunity to submit these comments in response to the Commission's Order for Comment issued in this proceeding on May 24, 2022 (the "Order").[1] Improving interconnection of distributed energy resources ("DERs") is critical to Virginia's clean energy transition and the continued growth and investment in Virginia's clean economy. These comments discuss key reforms that are necessary to address existing DER interconnection barriers and enable access to clean and renewable energy from DERs. CHESSA and CCSA request that the Commission initiate a rulemaking proceeding to update the Commission's Chapter 314 Regulations Governing Interconnection of Small Generators and Storage, in addition to establishing one or more technical working group(s), to address the issues discussed below in these comments.

I. INTRODUCTION

A. Overview

Across the U.S., customers are increasingly deploying DERs, in particular distributed generation ("DG") such as rooftop solar, community solar, and energy storage. The motivation behind the adoption of these resources is to lower electricity bills for customers while increasing energy security and resiliency. These are key customer priorities in response to increased inclement weather conditions and other disasters that can affect access to electricity. Beyond the direct and clear benefits for customers, distributed generation also carries the potential to provide immense benefits to the system and electric grid. DERs can lower system costs, increase system

[1] PUR-2022-00073, *Ex Parte: In the considering utility distributed energy resource interconnection-related issues and questions*, Order for Comment (May 24, 2022).

resiliency, and reduce carbon emissions.[2] The Virginia legislature recognized the benefits to customers of deploying DERs through numerous pieces of legislation, most notably the Virginia Clean Economy Act ("VCEA") (2020 Va. Acts 1193) and the Shared Solar Statute (2020 Va. Acts 1238).

Since the enactment of these policies in 2020, based on experience from CHESSA and CCSA member organizations active in Virginia, the volume of DER interconnection applications has increased dramatically relative to historic levels. Around the time of the enactment of the VCEA and other clean energy legislation, the Commission finalized revisions to the rules governing interconnection of distributed resources (Chapter 314) for Virginia utilities. The new rules were finalized following an opportunity for stakeholders to comment and engage with the Commission on redlines to Chapter 314. While the changes made to the rules provided modest improvements to the process, the distribution interconnection process continues to be antiquated and ill-prepared for the 21st century grid. The existing procedures not sufficient to enable the amount of renewable energy additions required by the Commonwealth's transformational energy goals.[3]

B. Paradigm Shift

Virginia is on the cusp of rapid DER growth and can benefit from leveraging best practices from other markets that have already made greater strides toward grid modernization. The experience of those markets has demonstrated that there are inherent flaws with regard to

[2] Virginia Commonwealth University's L. Douglas Wilder School of Government and Public Affairs, Center for Urban and Regional Analysis, *Accessing the Benefits of Distributed Solar in Virginia*, https://virginiasolarforall.com/wp-content/uploads/sites/62/2020/01/cura_solar_report_-_1-22-20.pdf.

[3] The VCEA requires Dominion Energy, a Phase II Utility, to procure 1,100 MW of DG generation from solar facilities no larger than 3 MW by the end of 2035. Va. Code § 56-585.5(D)(2). The VCEA also requires Dominion Energy to meet one percent of the mandatory renewable portfolio standard requirements with distributed generation resources no larger than one megawatt. Va. Code § 56-585.5(C). Separate from the VCEA, Virginia's Shared Solar Statute requires Dominion Energy to implement a Shared Solar Program for up to 200 MW of shared solar facilities in its service territory. Va. Code § 56-594.3(E).

harmonizing a high-DER marketplace with the existing regulatory paradigm, which evolved over decades to support a substantially different electric generating sector.

The basic premise for interconnection of any technology at scale still largely relies on the traditional principles of cost causation. When a new large natural gas or coal-fired power plant is constructed, the sole beneficiary of any work required to interconnect that facility to the grid is the developer and owner of the facility. Moreover, those facilities had large budgets and could easily absorb the costs of those upgrades. Accordingly, cost causation became the nearly universal approach that public utility commissions across the nation adopted to govern the treatment of the interconnection costs.

Distributed generation, however, is substantially different from that large, centralized system, and regulators and stakeholders in states with more advanced DER interconnection procedures have increasingly come to recognize that a new regulatory paradigm with substantially different metrics and incentive structures will be required to address the complicated issues of incorporating increasing amounts of DER on the grid. This reexamination is grounded in a recognition that much of the work that utilities identify as necessary for DG interconnection should more properly be categorized under the rubric of "grid modernization." In particular, it is worth noting that the grid upgrades required to interconnect significant quantities of DG will also ultimately create benefits for all customers not only by increasing the amount of clean energy generation on the grid, but also in the form of increased reliability and capacity to meet new load demands from electrifying the transportation and building sectors. As such, treating interconnecting customers as the sole beneficiary of these upgrades is improper and arguably results in a cost shift from ratepayers (who would eventually need to pay for the upgrades to meet electrification needs were it not for DG triggering the need for them sooner) to interconnecting DG customers. The current paradigm also fails to incentivize the utilities to complete the work expeditiously. The answer to the problem presented by the continued application of the cost causation principle is the establishment of a new framework for paying for bulk power system upgrades that equitably distributes costs across all beneficiaries (i.e., ratepayers and interconnecting customers).[4]

C. Summary of Key Interconnection Issues in Virginia

Interconnection policies are iterative - as technologies and trends evolve - and it is necessary to regularly reassess and adjust to meet the circumstances of the moment and prepare for the future. Interconnection challenges were addressed in several other recent dockets at the Commission, including Dominion's 2020 and 2021 Renewable Portfolio Standard filings[5] as well as the 2021 Grid Transformation filing.[6] The Commission opened this proceeding in recognition of the need for additional review of the current interconnection processes. The following section provides a high-level snapshot of current interconnection experiences in Virginia and the associated market implications. However, as laid out in the following section, there are many additional layers of issues that need to be addressed. Further, interconnection standards and procedures need to evolve as new technological solutions emerge and experience

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[4] Both the Massachusetts Department of Public Utilities and the New Mexico Public Regulation Commission have recently been exploring the concept of a multi-beneficiary cost allocation framework as an alternative to the cost causation framework. Notably, the proposed framework put forth by each agency would require a demonstration that there are truly multiple beneficiaries for upgrades to be eligible for cost sharing with ratepayers (*e.g.*, substation transformer replacements, reconductoring of distribution feeders, distribution protection measures, transmission related upgrades triggered by resources interconnecting to the distribution system, etc.) and would not cover upgrades that truly only benefit a specific project (e.g., a dedicated feeder to the point of interconnection). For more information, *see* D.P.U. 20-75 in Massachusetts and Case No. 21-00266-UT in New Mexico.

[5] *See* Case No. PUR-2020-00134, *Ex Parte: Establishing 2020 RPS Proceeding for Virginia Electric and Power* Company; Case No. PUR-2021-00146, *Petition of Virginia Electric and Power Company, For approval and certification of the proposed CE-2 Solar Projects pursuant to §§ 56-580D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under § 56-585.1 A 6 of the Code of Virginia, and a prudence determination to enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia.*

[6] Case No. PUR-2021-00127, *Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia.* Final Order at 26 (Jan. 7, 2022); *see also* Case No. PUR-2021-00127, Pre-Filed Staff Testimony of Michael A. Cizenski at 9-10 (Sept. 24, 2021).

is gained. The evolving interconnection landscape will require ongoing dialogue between stakeholders and an effort to address and resolve problems as they come up.

i. Excessive Study Delays:

The distribution interconnection process is one of the main stumbling blocks for distributed generation in the Commonwealth, as is evident by the poor showing in Dominion's small scale solar request for proposals (RFPs) over the past few years. Dominion Energy issued an RFP for DG projects 3 MW or less in 2019, 2020, and 2021. Each year the Company sought between 50-80 MW of projects. However, as Dominion Energy's 2020 and 2021 RPS filing show, only about 4 MW of utility-owned distributed solar projects have materialized.[7] The current distribution interconnection process and technical standards will not allow for the DG goals of the state to be achieved in an affordable and timely manner. While Dominion currently estimates a 12-month study timeline for developers who are in position A on a transformer, developers have noted anecdotally that in the past few years, it can take more than 16 months to complete a study for a single project. Worse, projects at a given substation to the same transformer are studied sequentially, meaning that the next project seeking interconnection must wait for the lengthy review process to be fully complete for the prior project before getting its own evaluation.

ii. Cost-Prohibitive Direct Transfer Trip Requirements:

Even after a project completes this lengthy process, the resulting interconnection cost is often prohibitive. For example, interconnection of distributed generation requires Direct Transfer Trips ("DTT") in most instances, rather than relying on inverter-based solutions to ensure the

[7] *See* Case No. PUR-2021-00146, Final Order at 18 (discussing the combined 3.6 MW (AC) of CE-2 distributed solar projects.) While Dominion received approval from the Commission for 33 MW of distributed solar PPAs in the 2021 proceeding, Dominion noted that many of those projects had not completed their interconnection studies and therefore the viability of those is unclear. *Id.* at 35; Tr. 205-08.

safety and reliability of the system. The DTT requirement, coupled with aging distribution infrastructure across the Commonwealth, often triggers interconnection costs between $1 million and $3 million, a massive portion of the project cost for a system under 3 MW. Moreover, costs associated with this infrastructure are often identified during the last steps in the study process. The costs are often a result of upgrading outdated substation infrastructure.

iii. Dominion's Steps to Improve DER Interconnection:

CHESSA and CCSA recognize and appreciate the steps Dominion Energy has taken to work with the Commission and stakeholders to better interconnect distributed generation to its system. First, Dominion Energy responded to industry requests for a public interconnection queue in 2021 by publishing its interconnection queue on a quarterly basis beginning late that same year.[8] Moreover, Dominion Energy has committed to enhancing their hosting capacity maps to provide greater detail and granularity. Dominion also agreed to providing a unit cost guide, with greater insight into potential equipment and upgrade costs.[9] Finally, Dominion has stated that it increased its resources and capabilities for more efficient processing of interconnection applications.

iv. More Action is Needed to Address Interconnection Problems:

The recent revisions to Chapter 314 and the improvements made by Dominion Energy are not adequate to meet the Commonwealth's environmental and energy priorities for DERs in a timely and affordable manner.[10] The current process cannot scale or run efficiently. With the

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[8] Dominion Energy, *Virginia Queue Status Report*, https://www.dominionenergy.com/virginia/large-business-services/using-our-facilities/parallel-generation-and-interconnection.

[9] Case No. PUR-2021-00127, Ex. 38 (Frost Rebuttal Testimony) at 8 (discussing unit cost guide); Dominion Energy, *Interconnection Parameters for Distributed Energy Resources* (Feb. 14, 2022), https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/large-business/parallel-generation/der-interconnection-parameters-manual.pdf?la=en&rev=6c2882dc58af4119a25640f44fb178bd.

[10] Case No. PUR-2018-00107, *In the matter of revising the Commission's Regulations Governing Interconnection of Small Electrical Generators*, Order Adopting Regulations (July 29, 2020), https://www.scc.virginia.gov/docketsearch#caseDocs/138804.

rapid increase in interconnection applications, sequential studies are not a sufficient method for studying projects. Only with robust DER integration processes can these systems become beneficial to the grid, prevent unnecessary spending on infrastructure by the utility, and enhance the system's resilience.

II. RESPONSES TO THE COMMISSION'S DER INTERCONNECTION QUESTIONS

In this section, CHESSA and CCSA respond to the eight questions that the Commission asked in the Order.

A. What are the primary obstacles (e.g., sources of delay or cost) to the interconnection of DER on the distribution system?

The current interconnection processes and timelines prevent Virginia from meeting its environmental and economic legislative requirements in a timely and affordable manner. Many of these challenges are a result of an interconnection process that simply cannot scale to the volume of resources needed to be deployed across the grid in the coming decade. Change is necessary to facilitate a 21st century grid that provides safe, clean, and reliable electricity.

Below, CHESSA and CCSA outline the key challenges facing the industry. Given that most of Virginia's distributed generation policies focus on the Dominion Energy service territory, these comments are focused on the industry's experience with Dominion Energy's interconnection process and application of Chapter 314 rules.

i. Study Timelines & Sequential Studies

One of the most pressing challenges for distributed generation interconnecting in Virginia is the length of the study timeline, which is compounded by a regime of sequential studies where only one project is studied at a time.

CHESSA and CCSA members applying to the Dominion Energy interconnection queue have experienced average study timelines exceeding a calendar year for projects in the "A" position. These delayed study timelines violate the Commission's regulations, which include specific timelines for each of the three studies: 30 business days for the feasibility study; 45 business days for the impact study; and another 45 business days for the facilities study.[11]

While Dominion Energy has endeavored to address the bottleneck around feasibility study timelines by increasing its in-house staff and outside consultants, these changes will only address the first study phase, potentially pushing the bottleneck to subsequent study processes. Projects lower in the queue may wait multiple years before completing the study process and receiving an interconnection agreement.

With these delayed study timelines, all interconnection applicants are exposed to uncertainty regarding the timing of study deliverables. By way of comparison, states with greater experience with high penetration of distributed generation can consistently complete interconnection studies in less than a year. For example, utilities in New York (a state with a goal of installing at least 10 gigawatts of distributed solar by 2030)[12] are limited to 10 business days to complete application reviews; 15 business days to conduct a preliminary review; and 60-80 business days to complete a Coordinated Electric System Interconnection Review ("CESIR").[13] These timing requirements are largely met: based on publicly available queue data, projects between the size of 3-5 MW that applied for interconnection with National Grid and Avangrid in 2020 and 2021 obtained CESIRs within an average of 200 and 163 calendar days, respectively.[14]

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[11] 20 VAC 5-314-70(C) – (E).

[12] New York State Energy Research and Development Authority, *Governor Hochul Announces Approval of New Framework to Achieve at Least Ten Gigawatts of Distributed Solar by 2030* (April 14, 2022), https://www.nyserda.ny.gov/About/Newsroom/2022-Announcements/2022-04-14-Governor-Hochul-Announces-New-Framework-to-Achieve-Ten-Gigawatts-of-Distributed-Solar.

[13] New York State Department of Public Service, *Distributed Generation Information,* NYS Standardized Interconnection Requirements, https://www3.dps.ny.gov/w/pscweb.nsf/all/dcf68efca391ad6085257687006f396b.

[14] New York Department of Public Service, *SIR Inventory Information, Utility Interconnection Queue Data (May 2022),* https://www3.dps.ny.gov/W/PSCWeb.nsf/All/286D2C179E9A5A8385257FBF003F1F7E.

Likewise, Massachusetts, which has nearly 4 gigawatts of distributed solar already installed,[15] has a standard interconnection process timeline of 105 days, and averaged 98 days[16] for National Grid and 132 days[17] for Eversource-East, respectively, for projects applying in 2021.

In Virginia, the 2020 revisions to Chapter 314 were intended to enable more efficient interconnection by providing higher study fees that would allow the utilities to hire more resources to conduct the studies in the timelines required under the interconnection regulations.[18] Furthermore, the rules update enabled the "B" position project to be studied in parallel with the "A" position for some part of the study timeline.[19] While this was a good first step, it is insufficient to enable Dominion Energy to manage the scale of interconnection applications that we are seeing in Virginia.

ii. Cost Estimates

As mentioned above, Dominion Energy has provided a unit cost guide to help developers anticipate utility upgrade costs based on general costs estimates. This is certainly an important step to provide interconnection cost transparency, but developers also need more details in the interconnection studies.

First, the level of detail in Dominion Energy's study reports is insufficient to provide developers insight into the reviews performed by the utility and the types of grid constraints and issues that are under investigation in the study process. Massachusetts' utility studies are 50

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[15] Solar Energy Industries Association, *Massachusetts Solar* (through Q1 2022), https://www.seia.org/state-solar-policy/massachusetts-solar.
[16] Massachusetts Department of Public Utilities ("DPU"). Docket # 22-30. Filing by Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, on April 1, 2022. See Exhibit A.
[17] Massachusetts DPU. Docket # 22-36. Filing by NSTAR Electric Company d/b/a Eversource Energy, on April 1, 2022. See Attachment A.
[18] Case No. PUR-2018-00107, *In the matter of revising the Commission's Regulations Governing Interconnection of Small Electrical Generators*, Order Adopting Regulations (July 29, 2020), https://www.scc.virginia.gov/docketsearch#caseDocs/138804.
[19] 20 VAC 5-314-38(B).

pages and include detailed information regarding study methodology and costs. This information helps developers better understand the scope of work, the grid constraints, and reliability issues of concern to the utility. Greater transparency in the Dominion Energy interconnection study reports will enable developers to make more informed project decisions. Additionally, cost estimates in the Dominion Energy study reports are not provided at the level of granularity that developers require to understand risks. With volatility in materials and pricing it is critical to understand, for each stage of the study process, the components of the costs, the level of accuracy of the estimate, and the amount of contingency included.

Second, Dominion Energy does not provide a comprehensive statement of upgrade costs until the final stage of interconnection study, often a year after the study began. This leads to additional work and inefficiencies for both the utility and the developers. Projects economics depend on the upgrade costs required for interconnection. Providing cost information early in the study process would enable developers to make an informed decision about withdrawing a non-viable project, rather than continuing through the study process to find out if a project is financially viable after the facilities study. Under the current system, developers are forced to complete the feasibility study, system impact study, and facilities study before receiving a comprehensive scope and cost estimate. This is incredibly inefficient for projects that are determined not to be viable. If reasonable cost estimates were provided early in the study process, only the viable projects would continue through the study phases; saving developers time and money while also reducing the volume of interconnection applications and enabling Dominion to more efficiently study viable projects. CHESSA and CCSA members have experienced project cost estimates for interconnection upgrades surging by over $2 million between the system impact study and the facilities study, ultimately resulting in project withdrawal from the interconnection process.

Finally, if a developer agrees to proceed with the estimated cost of interconnection provided in the Smaller Generator Interconnection Agreement ("SGIA"), they are told that they will be billed at the end of the construction process and that Dominion Energy can make any changes to the final bill to reflect the actual cost of the upgrades. The absence of an upward bound on cost overruns for construction serves as a roadblock to financing for projects. Projects that were quoted $500,000 for interconnection, for example, but then receive a final cost of $1,000,000 may be underwater as a result.

A practice other states have used to address this issue is to cap the amount that a utility can exceed its estimate. This approach is explained in the National Renewable Energy Laboratory paper titled "New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues."[20] As examples, in Massachusetts[21] and California[22] cost estimate overruns are capped at 25% of the total project cost. In the approach California and Massachusetts have adopted, utility shareholders are responsible for additional costs beyond the cap while other cost envelope models have assessed cost overruns to the utility rate base. In either event, the utilities retain responsibility for the accuracy of their estimates that help inform important development decisions.

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[20] National Renewable Energy Laboratory, *New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues* (Feb. 2019), https://www.nrel.gov/docs/fy19osti/72038.pdf.
[21] Massachusetts DPU Docket # 11-75-E, Order on the Distributed Generation Working Group's Redlined Tariff and Non-tariff Recommendations, issued March 13, 2013, at 23 and 39.
[22] California Public Utilities Commission. Rulemaking 11-09-011, *Alternate Decision Instituting Cost Certainty, Granting Joint Motions to Approve Proposed Revisions to Electric Tariff Rule 21, and providing Smart Inverter Development a Pathway Forward for Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric Company.*

In sharp contrast, Dominion Energy's study reports include a disclaimer[23] that the reported costs are non-binding on Dominion, depriving developers of the ability to make an informed assessment about cost or outcome despite a lengthy interconnection study process. Developers expend considerable resources to obtain interconnection studies. Utilities should be bound by the information provided in those studies. Moreover, the utilities should be required to provide regular reports to the project owner as expenses accrue to ensure that the project owner is aware of the expenses and can have a dialogue about the costs. CHESSA and CCSA recommend that the Commission adopt a cost envelope and cap on estimates to provide reasonable certainty regarding interconnection costs.

iii. Interconnection Dispute Procedures

Virginia lacks a reasonable dispute mechanism to challenge interconnection study outcomes or cost estimates. The Commission's existing interconnection dispute regulations (20 VAC 5-314-100), which are reflected Article 10 of the Commission's Small Generator Interconnection Agreement form,[24] need to be enhanced.

Greater transparency around the interconnection impact assessment and cost estimates and assumptions in the studies are imperative. Cost updates throughout the interconnection process will allow developers to have an ongoing dialogue with the utility interconnection team about project cost estimates. Conversely, under the current process, if a developer opts for separate feasibility, system impact, and facilities studies, they merely receive the study and can proceed to the next study by executing a new agreement. There is not an option to schedule a call

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[23] *"The Combined Study Cost is an estimated cost only. No engineering has been performed to arrive at the cost and Dominion Energy Virginia does not guarantee the accuracy or completeness of this cost. The estimates do not include the feasibility, cost, or time required to obtain property rights and permits for construction of the required facilities. All estimates have been calculated in good faith, however, are non-binding."*
[24] Schedule 10 of 20 VAC 5-314-170.

with Dominion Energy's interconnection team to receive a more comprehensive explanation of the costs, nor a reasonable mechanism to challenge the proposed upgrade cost.

In fact, after an interconnection upgrade cost is provided with the facilities study, a construction call is the first opportunity to discuss the project with Dominion Energy interconnection. The construction calls are, of course, not the forum for developers to better understand or potentially challenge if needed alternative methods or costs with Dominion. The only mechanism project developers have is to file a dispute formally. This leaves developers scrambling to understand the quote provided by Dominion, and why the costs are what they are.

While the establishment of rules governing a formal dispute resolution process likely need to be established, another effective tool that has been employed by several states is to create an interconnection ombudsperson, which can facilitate the efficient and fair resolution of disputes between parties and through which more informal guidance can be provided to stakeholders. Establishing such a position within a regulatory body creates a single point of contact through which customers can obtain information and seek advice on the proper steps to take to resolve issues and can also fulfill a role of mediating disputes between parties (e.g., utilities and interconnecting customers), helping to avoid the need for formal complaints being filed with a commission for adjudication. An ombudsperson can also monitor trends and recommend actions that a commission may take to resolve policy more proactively and/or technical issues that are arising.[25]

[25] Case studies for the successful implementation of dispute resolutions processes (including the establishment of an ombudsperson) in California, Massachusetts, Minnesota, and New York can be found in section V.2.A.iii. of Integrating Distribution Solar and Storage: The Keystones of a Modern Grid (see pages 20-22), attached as Appendix 2.

iv. Direct Transfer Trip

The most significant cost driver for projects seeking to interconnect to Dominion Energy's distribution system is the requirement to install Direct Transfer Trip ("DTT") equipment. This requirement is an unnecessary and arcane approach to addressing anti-islanding, given the fact that certified inverters already perform this function. DTT can add hundreds of thousands of dollars and potentially millions of dollars onto the price of DER interconnection, and many months of additional construction time.

The expense associated with the requirement to incorporate DTT is not merely the cost of receiver equipment and fiber needed between the facility to the substation. The DTT requirement at the project level in Virginia often requires additional costly equipment at the substation to house the DTT receiver such as a new or additional control house. In many cases this control house may be replacing an older structure or providing additional capacity for the utility to install additional protection and control equipment in the future. CHESSA and CCSA members reported that costs are on average between $2-$3 million and can be as high as $7 million for everything associated with the DTT requirement. This has resulted in many projects being withdrawn.

Instead of DTT, utilities should be obligated to study and utilize the functionality of certified inverters as a means of detecting islands. As discussed below in the best practices section, many states with higher levels of DER penetration have long moved away from requiring DTT and instead use inverter-based solutions and have adapted study practices to comprehensively evaluate the impact of the DER on the grid.

Consideration should also be given to project size and interconnection level. For example, an approach could be: all Level 2 interconnections use inverters, not DTT; all Level 3 interconnections under 5 MW use inverters, not DTT; and other Level 3 interconnections use inverters, not DTT and if that presumption is overcome, then the cost imposed on the interconnecting party should incorporate cost for cellular, rather than fiber, based DTT.

v. Lack of Equitable Cost Allocation

While the DER interconnection process currently identifies piecemeal upgrades to accommodate one DER project at a time, implementing only those that are affordable, the implementation of new programs in the Commonwealth also affords the utilities to holistically review the infrastructure needs it has to modernize the grid for multiple beneficiaries. While proactive planning for DER may not be in the scope of the Commission's inquiry there should be consideration given to cost sharing mechanisms that can be applied to both streamline the interconnection process, eliminate free ridership, and provide for broader customer benefits. Ideally, these costs sharing mechanisms would be incorporated into a long-term distribution planning process to ensure that all factors impacting the distribution system (e.g., DG growth, beneficial electrification, utility infrastructure replacement timelines, etc.) are considered.

Currently, the first project in queue at a substation (or transformer) has to bear the brunt of the entire substation upgrades if any are identified or "triggered" as part of the interconnection process. For the most part, the new infrastructure facilitates additional capacity at the substation that can be leveraged by projects downstream in the interconnection queue and the broader customer base if that triggering project should proceed. Some states have begun to confront those challenges by evaluating cost sharing opportunities between DER projects, and expanding those opportunities to infrastructure upgrades that are already part of a utility capital process.

vi. Lack of SGIA Refundability

In those occasions where the developer does not drop from the queue due to high interconnection costs and instead accepts the upgrade estimate, they must submit a letter of credit or surety bond for the entire amount of the interconnection upgrade within 30 days of receiving the SGIA, or risk getting kicked out of the queue. As the interconnection tariff is currently written and implemented by the utilities, the network and distribution upgrade portion of the SGIA (the non-project specific expenses) are considered non-refundable at the time of execution of the SGIA if there are *any* interdependent projects behind the project on the transformer. That can mean projects that have not begun their study process given that the utilities study projects sequentially.

Since interconnection upgrades are frequently multi-million-dollar investments, the full scope of costs is identified at a late stage of the process, and that security instruments are required immediately to cover 100% of the expense (which is non-refundable no matter the timeline to interconnect), there is significant undue burden on the developer that can force them to withdraw from the interconnection queue. Adding to the challenge, the Dominion Distributed Solar request for proposal (RFP) process associated with its VCEA obligation is not a first-come, first-served program, and therefore a project needs to provide a multi-million-dollar non-refundable deposit for interconnection without knowing if they have a buyer for their project or power produced. This level of risk is far greater than any financial reward of doing business in Virginia. Without more appropriate and commercially reasonable payment requirements and clearer pathways to refundability of the deposit, national developers will choose to go to other markets where the return on investment is less precarious.

vii. Material Modifications

The current interconnection rules, as implemented by Dominion, are extremely inflexible when it comes to providing customers and developers with the ability to reduce system size or move the point of interconnection without dropping from the queue. The definition of material modification must be relaxed to more closely align with modifications that can significantly impact the safety or reliability of the system while preserving flexibility through clear identification of non-material changes.

In particular, the material modification section greatly restricts the ability to incorporate energy storage to an existing interconnection application without requiring a new queue position. Given the benefits to the system of adding energy storage to distributed generation, we recommend better facilitating the interconnection of direct current configured systems without triggering material modification. The current standards do not allow for changes to daily production profile, which essentially precludes the addition of energy storage.

viii. Liability Insurance Requirements

Currently, most small-scale interconnections, i.e., rooftop solar interconnections that are typically sized 10 kW or less, interconnect under Chapter 315, which addresses interconnection for customer-generators participating in net energy metering. With the expected growth of rooftop solar over the next few years, it is important for the Commission to concurrently consider parallel changes to Chapter 315 of the Virginia Administrative Code to match any changes that are contemplated for Level 1 interconnections in Chapter 314.

While our members have reported that the Level 1 interconnection process in Chapter 315 appears to be operating fairly well–with anecdotal stories of increased interconnection timelines occurring even at that level–there is one easy fix to streamline the process: eliminate the proof of liability insurance requirement for Level 1 interconnections in Chapter 314 and for all net metering customers in Chapter 315.

20 VAC 5-314-160(1) requires the interconnection customer to possess $100,000 per occurrence in combined liability insurance for property damage or bodily harm if the system is 10 kW or less or $300,000 for all Level 1 systems over 10 kW. This provision is mirrored in Chapter 315, but it does not include the "per occurrence" language. While most homeowners

maintain more than adequate insurance to satisfy this amount, the requirement of proof of insurance, by declaration or otherwise, can slow the process by creating another touchpoint and can potentially hobble a project where a customer is unable to locate or provide timely provide documentary evidence of the homeowner insurance policy.

When standardized interconnection procedures were first adopted across the country for small generators, it was common to see these liability insurance requirements. But these insurance requirements have become anachronistic red tape since the utility industry has grown experienced with inverter-based technologies and most states have eliminated the requirement for small, inverter-based generators. CHESSA and CCSA are not aware of a single instance of an inverter-based system (out of millions of interconnected rooftop systems in the United States) causing damage to a utility that would give rise to a claim under the homeowner's insurance policy. Indeed, Dominion sent an email to solar installers on June 7, 2021, noting that it was going to start strictly adhering to the insurance requirement, indicating that it had not been doing so in the past.

TABLE 1. LIABILITY INSURANCE REQUIREMENTS IN STATE INTERCONNECTION PROCEDURES		
States w/out additional general liability insurance requirement for residential systems or systems < 20 kW	States that require $100,000 or more in general liability insurance for residential systems or systems < 20 kW	States with "per occurrence" language in insurance requirement
AL*, AZ, AR, CA, CO, DE, GA, HI, IL, IA, KS, KY, LA, ME, MD, MA, MI, MS, MT, NE, NV, NH, NJ, NY, OH, OK, OR, PA, RI, TX, UT, VT, WA, WY	CT, FL**, IN, MN, MO**, NM**, NC, SC, SD**, VA, WV, WI	ID*, NC, SC, WI, VA

*No statewide interconnection standard, but based on state's largest IOU practice.
** Florida exempts 10 kW or less from insurance requirement, but requires up to $1M for Level 2 Systems; Missouri exempts 10 kW or less, but requires $100k for net metered systems over 10 kW; New Mexico does not require for 10 kW or less, but up to $1M for up to 250 kW; SD $500k if over 10 kW, homeowners policy suffices if 10 kW or less.

There is no reason to require proof of insurance for Level 1 interconnections. A proof of insurance requirement for Level 1 projects unnecessarily and unreasonably slows the process of interconnection. CCSA and CHESSA request that the Commission eliminates this requirement. This change is a low hanging fruit fix that carries little to no risk for utilities and ratepayers because there have been no documented cases where a homeowner's policy has been called upon to cover losses to a utility due to operation of the generator.

B. What solutions have utilities implemented to facilitate the efficient interconnection of DER to the distribution system? Have they been effective? How can they be improved?

CHESSA and CCSA have been engaged in conversations with Dominion on distribution interconnection challenges since the start of 2021. The group has convened six times to date, exploring ways to resolve a number of issues including the public interconnection queue, unit cost guide, hosting capacity maps, DTT, and study timelines. CHESSA and CCSA appreciate the time and effort from the Dominion Energy interconnection team in discussing and addressing these issues. Most notably, Dominion has agreed to publish its interconnection queue on a quarterly basis. The industry has advocated for a monthly update to the data but recognizes the quarterly updates as an important first step. Moreover, Dominion has agreed to publish a unit cost guide that provides developers with an estimate on specific costs that enable them to understand the likely interconnection upgrade cost for their project.[26] Finally, following discussions with industry, Dominion Energy interconnection attended discussion forums with third parties that focused on this topic and shared that it has identified a task force to further evaluate DTT.[27]

C. What additional solutions do utilities plan to implement, or are considering for implementation, to facilitate the interconnection of DER on the distribution system?

CHESSA and CCSA are not aware of planned utility solutions to facilitate interconnection of DER.

D. Are there "best practices" in place in other jurisdictions that the Commission should consider?

The following response to this question delves into multiple categories, however it is worth calling out that there are existing technical reports that provide best practices and case studies associated with DER interconnection. Most notably, "Integrating Distributed Solar and Storage: The Keystones of a Modern Grid," authored by CCSA and Local Solar for All and published in February 2022, is a technical review inclusive of recommendations specifically geared toward regulatory considerations for enabling DER deployment.[28]

i. Improved Study Timelines

CHESSA and CCSA support increasing study fees to support staffing at the utilities that can ensure studies are conducted within the time frame outlined in the interconnection tariff. In addition, the CHESSA and CCSA recommend that the Commission require utilities to file and make public a quarterly report on the status of their performance of meeting study timelines in

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[26] Dominion Energy, *Interconnection Parameters for Distributed Energy* Resources, https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/large-business/parallel-generation/der-interconnection-parameters-manual.pdf?la=en&rev=510579a4207e4598a1aadcbc6bba56fd.
[27] Based on informal discussions with Dominion.
[28] A copy of this White Paper is attached as Appendix 1. The White Paper is also available online at https://www.communitysolaraccess.org/wp-content/uploads/2022/02/CCSA_BRO-White-Paper_20220214-1.pdf.

order to provide greater transparency. This could be included in the quarterly public queue reports. Currently the reports do not include the date a project becomes an "A position" project or whether it has selected individual or combined studies. CHESSA and CCSA welcome the opportunity to provide additional input on the interconnection report to help enhance the current report. Existing interconnection reporting frameworks, including the Massachusetts Timeline Enforcement Mechanism[29] and Maine's interconnection timeline quarterly and annual reporting process,[30] offer helpful models to monitor compliance with interconnection rules.

ii. Parallel Studies

CHESSA and CCSA recommend adopting a Pseudo-Parallel study approach. Under this approach, later queued studies would be able to start the study process as soon as the earlier queued project's impact study report (or combined study, as applicable) is complete. Upgrades required for earlier queued projects that may create dependencies are noted in study results as contingency upgrades so all applicants are aware of potential cost shifts should earlier queued projects withdraw.

CHESSA and CCSA also recommend condensing and optimizing the study process in order to improve utility and developer resourcing, reduce timelines, and provide comprehensive details regarding interconnection as an outcome of the impact study so that developers can withdraw their application if the interconnection upgrade is cost prohibitive. The optimized process would allow for a formalized and initial preliminary analysis to take the place of the current scoping meeting which would allow for important system area details to be identified and communicated before the formal study process begins. Moreover, CHESSA and CCSA

[29] Mass. DPU, Order D.P.U 11-75-F, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9233725.
[30] Maine PUC, Case No. 2021-00167, *Amendments to Small Generator Interconnection Procedures (Chapter 324)*, Order Amending Rule (Dec. 21, 2021).

recommend that a more robust and comprehensive study analysis would provide customers with a full picture of upgrades while still allowing for an optional facilities study process to allow for further refinement of scope and costs. For example, this process could be used to do a detailed time-domain study to evaluate alternatives to DTT, to identify the number of pole replacements required for reconductoring, or refine cost estimates to a greater cost accuracy margin.

Current Chapter 314 Interconnection Process (Level 3):

or

Proposed Interconnection Process (modeled on NY/MA):

All these improvements would reduce the overall study load for the utility given that many developers will have more information earlier on in the process, require less administrative processing time between study steps, and be better able to determine whether a project is financeable. Non-viable projects can be withdrawn from the study process earlier, reducing the volume of studies for the utilities to process and allowing other projects to proceed through the study process more efficiently.

iii. Pro Rata Cost Sharing

Virginia should take steps to effectively allocate costs in ways that support the cost-effective growth of DERs by adopting a cost sharing policy that distributes the costs across a more appropriate range of beneficiaries, properly recognizing that when constructing bulk power system upgrades of a certain magnitude, substantial benefits from constructing those upgrades may flow to customers other than to the DERs seeking to interconnect. Implementation of this approach should ideally be done in conjunction with reforms to distribution system planning procedures and the implementation of grid modernization measures to achieve the best results.

The Commission should consider implementing a cost sharing mechanism;[31] variations of which have been rolled out in Massachusetts, New York, Maine, and is under consideration in Maryland. In New York this cost sharing mechanism is called "Pro rata cost sharing," whereby a developer pays its share of the system upgrade. For example, if a $2 million interconnection upgrade enables 20 MW of capacity, and the project is only 5 MW in size, it would pay 25% of the total upgrade. The subsequent projects that seek to interconnect to the upgraded substation would pay their portion of the upgrade cost until the entire capacity is used up - and the upgrade costs are fully paid for. In the situation where not enough projects interconnect to support the full cost of the upgrade, the utility can rate base the remaining costs of the upgrade five years after the upgrade was triggered.

iv. Direct Transfer Trip

CHESSA and CCSA recommend that inverter functionality be evaluated as an alternative to DTT and be allowed for within the study process. Several utilities with higher DER

[31] For additional information, please refer to the options and recommendations explored in Appendix 1, the CCSA and Local Solar for All white paper, *Integrating Distributed Solar and Storage: The Keystones of a Modern Grid*, at 45-51.

penetration in the U.S. depend on a combination of passive and active anti-islanding methods resident in the inverter to address this risk.[32] For example, National Grid determined that most inverters - that are UL 1741 certified - do not require DTT and, instead, can use reclose blocking.[33] Other markets are similarly recognizing and exploring the benefits and advanced functionality of inverters.[34]

At a minimum, the utilities must enable opportunities for interconnection customers to pay for dynamic studies to evaluate inverter capability during an optional facilities study process (as described above). If the dynamic study shows that DTT is not required, the utilities should be required to consider and implement other alternatives, such as inverter-based solutions.

v. 25/75 Refundability

Interconnection deposit refundability policies in the Commonwealth must be adjusted to more closely reflect best practices in other states. In several states, a developer is required to pay 25% of the upgrade cost initially, and then the remaining 75% after certain milestones are achieved.[35] In situations where the developer terminates the interconnection agreement before the final milestone, they would not be required to pay the additional 75% and their deposit would be returned minus any expenses incurred. We propose the Commission adopt the same stance on refundability. This is the case in New York, where the utilities allow interconnection applicants 120 business days from when the utility confirms receipt of an advanced 25% payment to pay the

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[32] *See* Appendix 1, CCSA and Local Solar for All, *Integrating Distributed Solar and Storage: The Keystones of a Modern Grid* at 61-64.

[33] T&D World, *National Grid's Blueprint for DG Interconnections* (Jan. 25, 2018), https://www.tdworld.com/grid-innovations/generation-and-renewables/article/20970750/national-grids-blueprint-for-dg-interconnections.

[34] CCSA and LS4A. Integrating Distributed Solar and Storage: the Keystones of a Modern Grid. pgs. 61-64. Found here: https://www.communitysolaraccess.org/wp-content/uploads/2022/02/CCSA_BRO-White-Paper_20220214-1.pdf

[35] *See* Maine's Small Generator Interconnection Procedures, 65-407 CMR Ch. 324; New York's Standardized Interconnection Requirements,
https://www3.dps.ny.gov/W/PSCWeb.nsf/All/DCF68EFCA391AD6085257687006F396B?OpenDocument; Massachusetts Distributed Generation (DG) Guidelines,
https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12668672.

remaining 75% to the utility and where any unspent portions of these payments are refunded to the applicant. These types of gated deposits that increase as the project moves through the review period and clear rules regarding refundability will help establish a "first-ready, first-served" queuing process.

vi. Enhanced Interconnection Details in Study Reports

CHESSA and CCSA recommend that Dominion Energy provide greater clarity regarding their interconnection upgrade process by providing a more detailed breakdown of scope, methodology, and interconnection upgrade costs in the studies. The interconnection process could be improved by standardizing study report and cost estimate templates for uniformity across study types and utilities. In New York, the New York Joint Utilities have adopted a standardized template for preliminary screening[36] and study reports[37] to help support this function.

vii. Interconnection Dispute Mechanism

CHESSA and CCSA propose enhancements to the existing dispute resolution procedures in the Commission's regulations, which will help facilitate greater dialogue and understanding between the utilities and the development community.

First, there must be a mechanism to discuss study results and estimates with the interconnection teams before a construction call is scheduled. The dispute procedures should be updated to add a 10-business-day period for interconnection customers to submit questions and meet with the utility to discuss the facilities study or combined study results before proceeding to

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[36] New York State Preliminary Screening Template, http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/def2bf0a236b946f85257f71006ac98e/$FILE/21639312.pdf/Standardized%20Preliminary%20Screening%20-%20Template%202019-01-04.pdf.

[37] New York State Coordinated Electric System Interconnect Review Template, *http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/def2bf0a236b946f85257f71006ac98e/$FILE/88409379.pdf/JU%20CESIR%20Template%20V1.1%208-14-2018.pdf.*

the construction planning meeting. This opportunity for dialogue decreases the chances that a formal dispute mechanism would be needed.

Second, as for the dispute mechanism, when an interconnection customer notifies the utility of a dispute (20 VAC 5-314-100(B)), the utility should be required to provide someone with technical expertise and decision-making authority to participate in the dispute resolution process and discuss the disputed issues with the customer. Notification of a dispute should pause the applicable timelines in the interconnection rules, including the 30-business-day timeline to sign the SGIA (20 VAC 5-314-50(F)(1)) and the SGIA payment/financial security requirements (20 VAC 5-314-50(F)(2)) until the dispute is resolved. As discussed previously, many states have identified DG ombudsperson roles to facilitate these types of good-faith discussions and to avoid further regulatory action if unnecessary.[38]

E. What additional actions could the Commission take to help facilitate the interconnection of DER on the distribution system?

It is important for the Commonwealth to create both policy and technical working groups (or a single group tasked with both) made up of Commission staff, utilities, project developers, and other stakeholders with the technical expertise to help effectively implement technical standards. Many states have created ongoing interconnection technical and policy working groups, which have been instrumental in advancing interconnection policy to keep up with changing realities.[39] Such groups establish a forum for the exchange of ideas and information between utilities, industry, and other stakeholders and are often facilitated by policymakers and regulators. They allow for interconnection processes to evolve without the need for formal regulatory or tariff revisions but can also identify when more major changes such as these are

[38] *See* Appendix 1, CCSA and Local Solar for All, *Integrating Distributed Solar and Storage: The Keystones of a Modern Grid*, at 20-22.
[39] *See id.* at 17-20.

required and bring recommendations to regulators. They can also help foster better relationships between utilities and industry as technical and policy experts come together on a regular basis to find common ground on issues as they emerge. New York,[40] Massachusetts, Hawaii, Connecticut,[41] and Illinois have ongoing technical working groups.

CHESSA and CCSA additionally urge the Commission to consider adoption of standard smart inverter settings to enable additional DER to interconnect to the grid and to provide other potential distribution benefits. Activation of Volt-VAr and Volt-Watt functions provide a means for distributed energy resources utilizing smart inverters to respond autonomously to operational conditions on the grid to provide voltage support and other services. Utilization of Volt-Watt, in particular, can enable a utility to avoid grid upgrades by setting the inverter to curtail solar output at times where it would cause violation of acceptable voltage bands on the local distribution system. If Volt-Watt curtailment events become excessive, a utility can pursue the necessary upgrade to alleviate the condition that is causing the upgrade. This circumstance would indicate that the utility investment may have been needed to maintain voltage even absent the addition of solar, since the smart inverter function assures that solar is not the cause of operational violations.

Further, the national testing labs, certifying inverter compliance with applicable standards, are beginning to certify equipment using the updated UL 1741 SB. Several states, including Maryland, New York, and Pennsylvania, are now incorporating these requirements into

[40] New York State Department of Public Service, *Interconnection Technical Working Group, Statewide Interconnection Technical Documents*, https://www3.dps.ny.gov/W/PSCWeb.nsf/All/DEF2BF0A236B946F85257F71006AC98E; New York State Department of Public Service, *Interconnection Policy Working Group*, https://www3.dps.ny.gov/W/PSCWeb.nsf/All/0D7596DBBEF0380885257FD90048ADFA.
[41] Connecticut Public Utilities Regulatory Authority, *Connecticut Distributed Generation Technical Working Group*, https://portal.ct.gov/PURA/Electric/Interconnection-Technical-Working-Group; Connecticut Public Utilities Regulatory Authority, *Connecticut Distributed Generation Policy Working Group*, https://portal.ct.gov/PURA/Electric/Interconnection-Policy-Working-Group.

interconnection rules, requiring utilization of these standards by January or April of 2023. Consideration of incorporating UL 1741 SB standards in Virginia's interconnection standards is ripe for consideration and could do more to unlock the distribution benefits provided by distributed energy resources. We support formation of a technical working group to identify solutions that smart inverters may be able to provide to expand hosting capacity, enable more DERs, and help avoid upgrades by providing non-utility solutions.

F. What steps should the Commission take with regard to aggregation of interconnected DERs for possible participation by such aggregations in the PJM wholesale market, per FERC Order 2222? Are any such steps best addressed in this docket or in a separate proceeding?

These steps are likely best addressed in a separate proceeding as implementation of Order 2222 is not as directly related to interconnection. More likely, it will require the deployment of new hardware and software infrastructure that allows distribution companies to have greater visibility and control over the real-time operations of aggregated DERs on their distribution system. While it is important to consider what changes may be necessary, it is likely best dealt with separately and may be further informed by FERC's anticipated order on PJM's compliance filing, which is still under review.

G. Are there any changes to the Regulations Governing Interconnection of Small Electrical Generators and Storage (20VAC5-314) or other Commission actions that could enable the usage of IEEE-1547-2018 compliant inverters to facilitate the integration of DER on the distribution system? Are any such changes or actions best addressed in this docket or in a separate proceeding?

Given the highly technical nature of this topic, we recommend that the Commission separately convene technical experts to discuss the various implementation challenges. The establishment of one or more working group(s), as recommended in II.E above, could be an appropriate forum in which to discuss this in more detail. Other states[42] have avoided placing overly complex technical standards and requirements into their formal rules and have instead issued broader instructions that standards must be adopted by a date certain and left the implementation details to a working group, utilities, and other stakeholders (often with Commission involvement and supervision over the process).

H. Are there additional changes that could be made to the Regulations Governing Interconnection of Small Electrical Generators and Storage (20VAC5-314) that could facilitate the integration of DER on the distribution system? If so, please describe such proposed changes.

CHESSA and CCSA do not have any further recommended changes to the Regulations Governing Interconnection of Small Electric Generators and Storage at this time.

III. CONCLUSION

CHESSA and CCSA appreciate the opportunity to submit these comments regarding the current challenges preventing greater deployment of DERs in Virginia. The Commission should continue to focus on these issues and work with developers, utilities, and other stakeholders to move Virginia forward to grow our clean energy economy for the benefit of all Virginians. CHESSA and CCSA look forward to continuing the work on these important issues in this and subsequent dockets. CHESSA and CCSA request that the Commission initiate a rulemaking proceeding to update the Commission's Chapter 314 Regulations Governing Interconnection of Small Generators and Storage, in addition to establishing one or more technical working group(s), to address the interconnection challenges and solutions discussed in these Comments.

[42] *See* Appendix 1, CCSA and Local Solar for All, *Integrating Distributed Solar and Storage: The Keystones of a Modern Grid*, at 61-64.

Respectfully submitted,

CHESAPEAKE SOLAR & STORAGE
ASSOCIATION

AND

COALITION FOR COMMUNITY SOLAR
ACCESS

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Dated: August 1, 2022

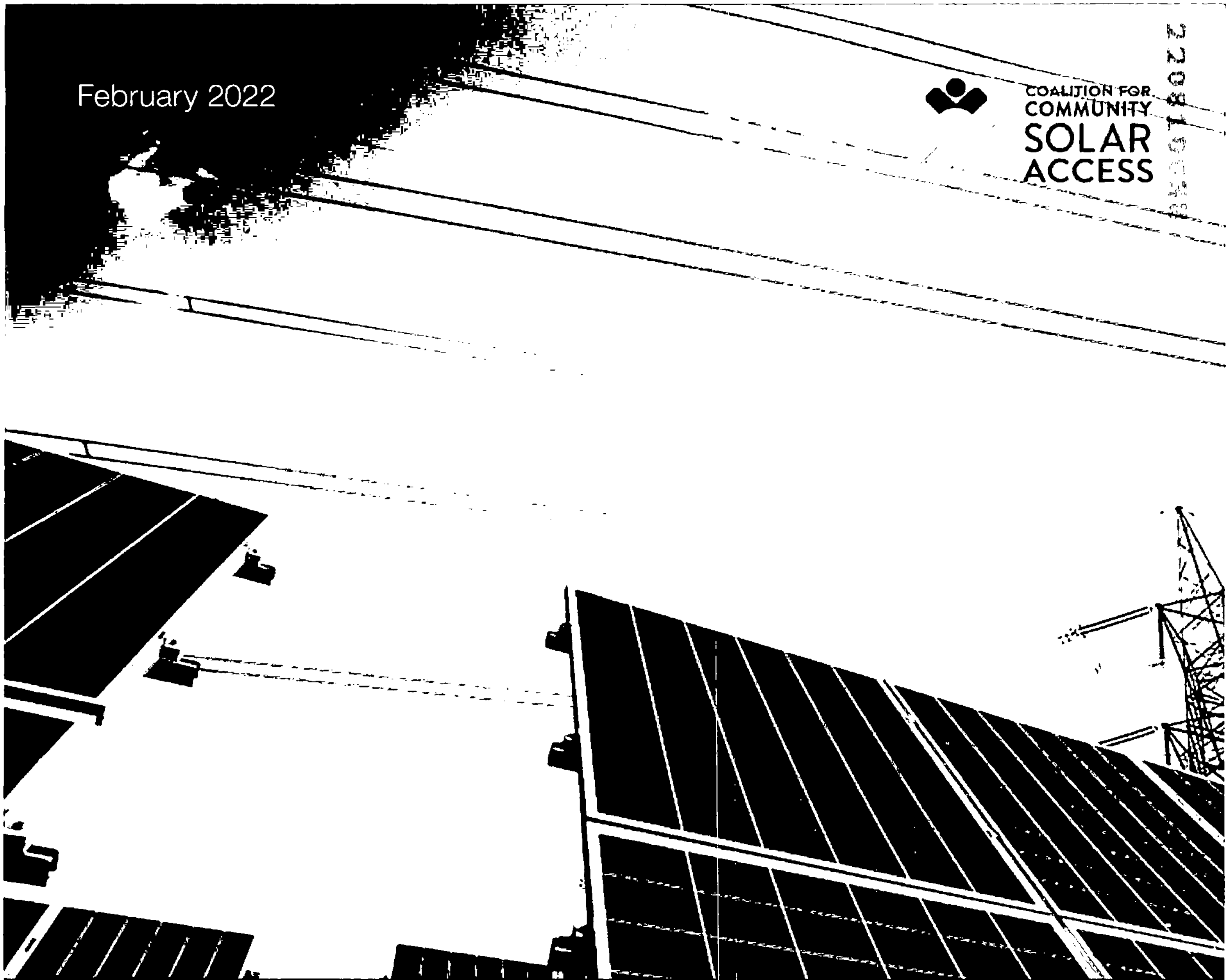
Appendix 1

Integrating Distributed Solar and Storage: The Keystones of a Modern Grid

The Coalition for Community Solar Access and Local Solar for All

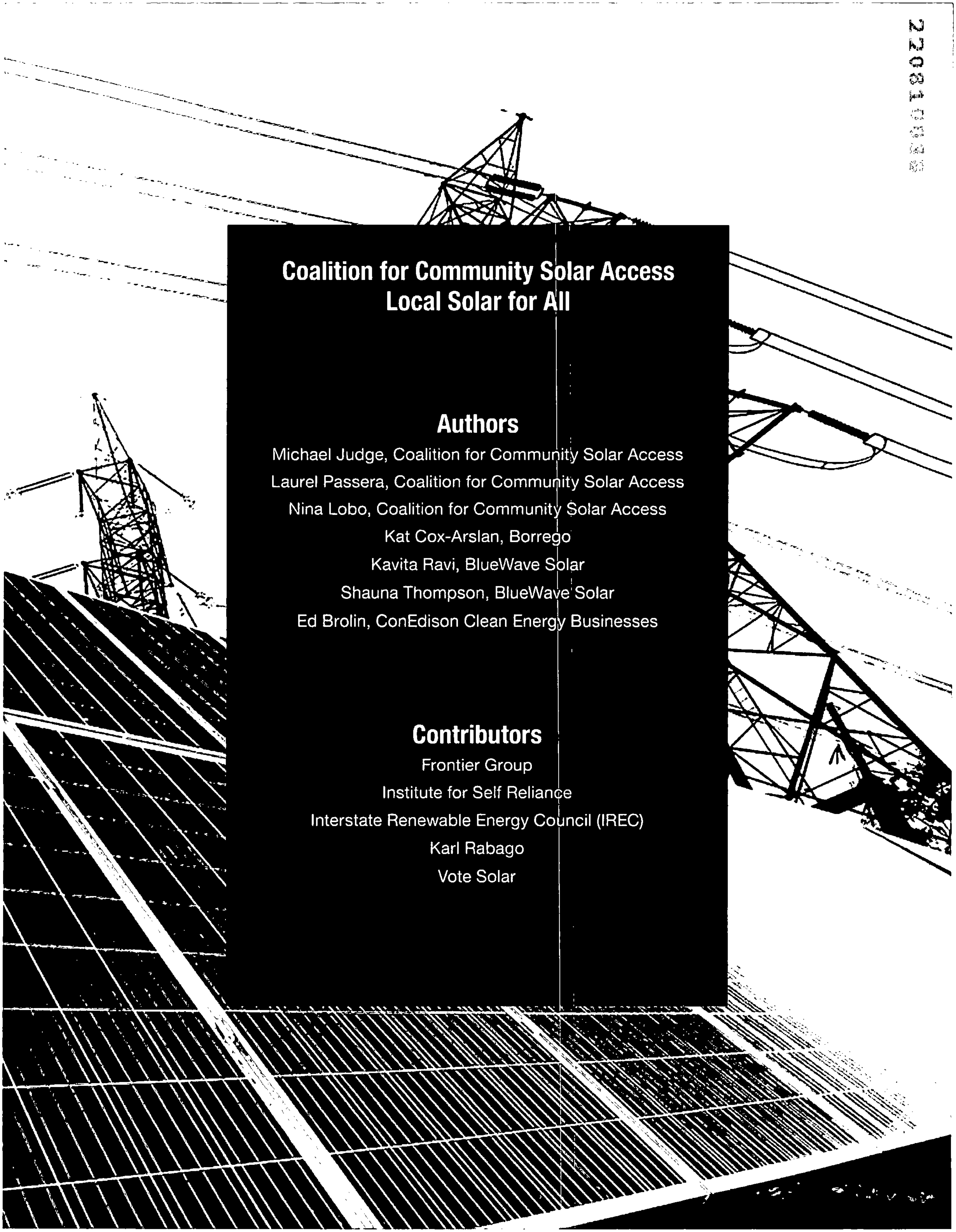
February 2022

COALITION FOR COMMUNITY SOLAR ACCESS



INTEGRATING DISTRIBUTED SOLAR AND STORAGE: THE KEYSTONES OF A MODERN GRID

Coalition for Community Solar Access
1380 Monroe St, NW #721, Washington, D.C. 20010



Coalition for Community Solar Access
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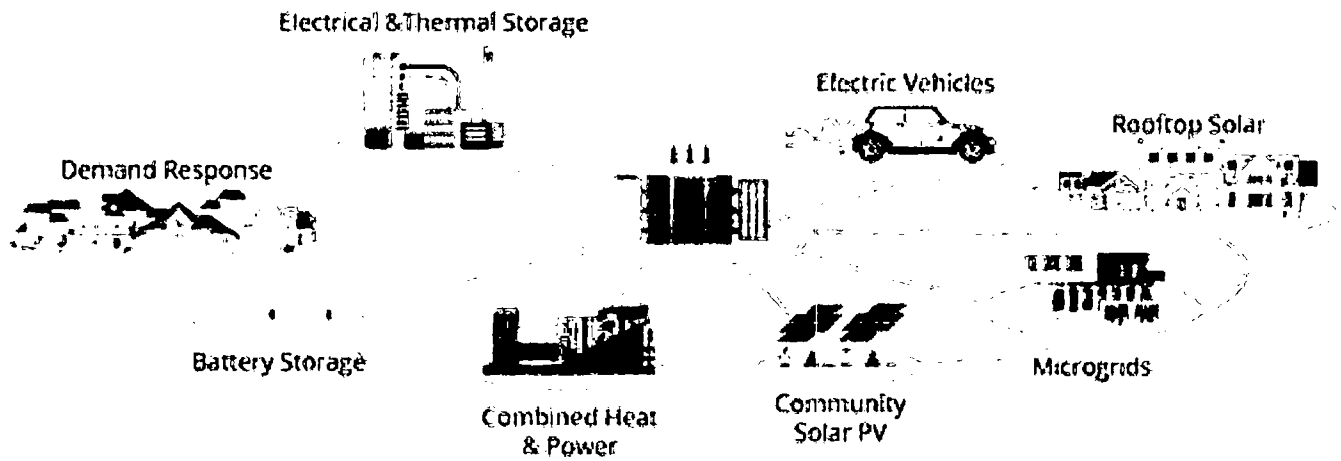
Executive Summary

The United States must transition to an energy sector powered by clean energy as rapidly as possible to meet ambitious state and federal clean energy and climate targets. It must also keep pace with an exponential increase in energy demand resulting from the electrification of the building and transportation sectors. To accelerate the rapid adoption required to meet these combined needs, federal and state policymakers will need to intentionally reform and make proactive investments in comprehensive system planning and grid modernization, which will significantly improve the process of physically integrating distributed energy resources (DERs) into the electric grid and will lead to significant economic benefits for all Americans[1]. Guided by legislators and regulators, these reforms and investments will help facilitate the transformation of the current electric grid into one that is cleaner, more affordable, smarter, flexible, and more resilient.

Types of DERs



Source: OATI (https://www.oati.com/Solution/Smart-Energy/distributed-energy-resource-management)

This white paper outlines the tools needed and steps that should be taken by policymakers, utilities, and industry stakeholders to plan for the future electric grid and to enable the transition to occur as rapidly and seamlessly as possible. More specifically, this paper proposes a systemwide approach to DER integration, with an aim to transition to a regulatory framework that:

- Solves the challenge of how to effectively integrate clean energy generation through integrated distribution and transmission system planning and efficient interconnection procedures;
- Fairly compensates and incentivizes utilities to expeditiously integrate DERs;
- Appropriately allocates grid upgrade costs among customers; and
- Leads to the provision of clean, reliable, and cost-effective electric service to all Americans.

To accomplish these overarching objectives, this paper focuses primarily on issues at the distribution system level, examining the most common challenges currently preventing rapid DER adoption, and lays out

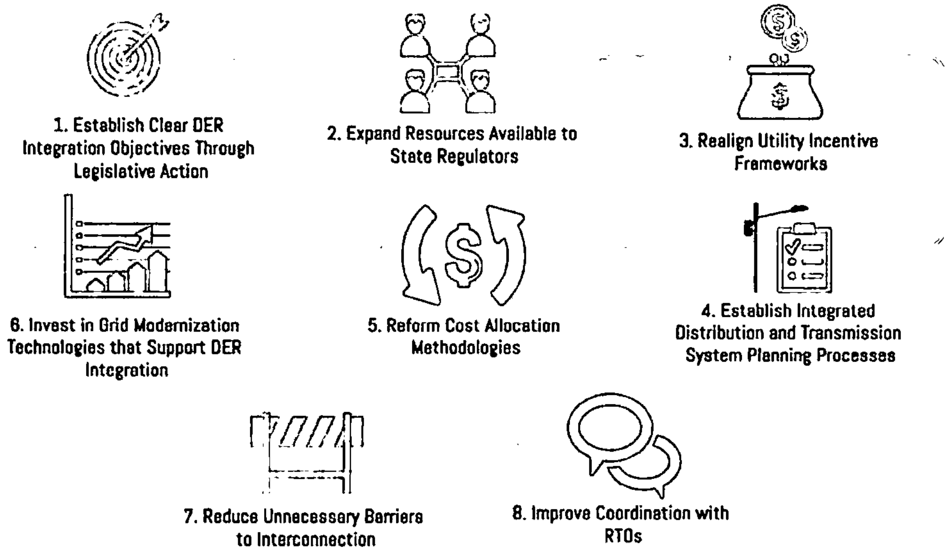
1 Comprehensive modeling carried out by Vibrant Clean Energy and the Local Solar for All Coalition has demonstrated that to achieve President Biden's climate and equity goals at the lowest cost, it will be necessary for the United States to deploy at least 103 gigawatts (GW) of distributed solar and 137 GW of distributed energy storage by 2030. Scaling up these resources was also shown to enable the deployment of 579 GW of utility-scale solar and 442 GW of wind. It was also shown to save all ratepayers over $109 billion by 2030 compared to deploying only utility-scale renewables as well as lead to the creation of 1.2 million new jobs by 2030.

a roadmap to overcome and facilitate this transition to a higher DER future by focusing on corresponding solutions. The following sections of this paper will:

- Introduce guiding principles to rapidly incorporate DERs utilizing advanced technology integration and policy reform;
- Describe our vision of a high DER future;
- Explore common challenges faced by utilities and developers when integrating DERs;
- Outline a roadmap for stakeholders with recommendations on how to achieve objectives; and
- Provide case studies for DER best practice procedures and technology-driven solutions.

While many case studies are provided below highlighting approaches taken by states to develop regulatory constructs that will enable a decarbonized, high-DER future, the reality is that no state has yet developed a comprehensive set of solutions to the challenges of creating the conditions that will enable the high-DER future necessary to realize our GHG reduction goals and mandates. This paper is a resource that policymakers, state regulatory bodies, and utilities can use to accelerate the path toward an advanced technology-driven grid design where DERs are integrated seamlessly, their value is maximized, they are rapidly and reliably dispatched as needed, and the costs of integrating DERs are spread affordably and equitably among all grid beneficiaries.

DER Integration Roadmap



With respect to the roadmap that should be followed to achieve these outcomes, this paper recommends that policymakers, regulators, utilities, and other stakeholders take the following steps:

1. Establish Clear DER Integration Objectives Through Legislative Action

   Regulatory bodies such as public utility commissions are tasked with ensuring reliable, safe, and cost-effective electric service. Such agencies must optimize the interests of all consumers and utilities and strive to make decisions that are consistent with the public interest. Because these bodies are often quasi-judicial, they are often less likely to stake out major policy positions unless they have been clearly articulated by the state legislature. This quasi-judicial role and tension between public and private interests creates an environment where regulators are often disinclined to expand upon conservative interpretations of legislative intent. Accordingly, state legislatures should enact laws that provide state regulatory agencies with the requisite authority, direction, and resources to address challenges related to DER integration. Four examples of where state legislatures can be particularly helpful when establishing clean energy and climate mandates would be to:

- Clearly communicate interconnection and grid planning needs of programs;
- Provide regulatory agencies with the financial resources they need to effectively administer and regulate DER programs;
- Direct regulatory agencies to prioritize decarbonization and grid modernization alongside more traditional priorities such as safety, reliability, and affordability; and
- Set clear deadlines for regulatory bodies to ensure progress is made in a timely manner.

2. Expand Resources Available to State Regulators and Ratepayer Advocates

Utilities can be slow to create new policies and procedures for specific technology adoption even after state incentive programs calling for such advancement have been published, leading to situations where they drive the conversation at the state level. To ensure utilities are proactively planning for a substantial increase in DERs, state regulatory bodies and ratepayer advocates must have the same level of technical expertise as utility staff when coordinating on the best path forward to high DER integration, which may require augmenting staffing at the state regulatory agency and/or ratepayer advocate or increasing reliance on consultants. We strongly urge that states provide state regulatory and policy agencies with more funding to hire additional staff and experts.

Additionally, while the federal government generally does not regulate activity at the distribution level nor does it directly set state policy, it can provide incentives and support to help states expand their own resources as well as to carry out the stakeholder processes needed to advance distribution grids and grid planning to the 21st century. Federal assistance on these topics may or may not require authorizing legislation, but likely could be provided by the Department of Energy (DOE) directly or acting in conjunction with other organizations. The federal government has also historically provided support to research and development efforts, particularly through the DOE national labs, which should be continued and expanded to focus on the reforms necessary for states to enable a high DER future.

3. Realign Utility Incentive Frameworks

When utilities do not have incentives or mandates to conduct distribution system planning with an eye towards decarbonizing, implementing grid modernization upgrades, or accomplishing interconnection work efficiently, they will likely choose to prioritize other efforts. Regulatory bodies can address this by adopting performance-based regulation mechanisms that specifically measure objectives and incentivize or penalize utilities based on their progress in meeting specific metrics that align utility incentives and profits with state policy.

Specifically, utilities must be able to plan for changes to the electric grid other than those exclusively impacting safety and reliability. Going forward, planning measures designed to address decarbonization and electrification targets must become an equal part of a utility's service obligation to its customers. It is also critical to tie decarbonization into updated planning processes so that ratepayers get the most value from upgraded infrastructure as climate goals are being met. This realignment will ensure that utilities can act as a facilitator of DER adoption while still earning a reasonable rate of return. By reforming existing regulatory frameworks and directing utilities to serve as DER facilitators, legislators, policymakers, and regulators can take steps to effectuate the changes necessary to facilitate a future with a high number of DERs.

4. Establish Integrated Distribution and Transmission System Planning Processes

   To integrate technologies such as advanced inverters and batteries, electric vehicles, electric heat pumps, and other DERs as quickly and efficiently as possible, a long-term plan of how best to incorporate these new features into the electric grid (both distribution and transmission) is essential. Such planning should be conducted by utilities in coordination with long-term planning committees at state agencies and regional transmission organizations (RTOs). State regulators or other governing bodies should also convene stakeholder working groups to identify key issues and think through and implement a better process for coordination.

   This undertaking will not be easy, nor will it be quick, so states must commence such efforts with an organized plan of action, clear objectives, and with an understanding that there are decades of tradition, procedures, and precedent to overcome. Also, greater emphasis on stakeholder collaboration and input in the planning process is necessary as we move to a future with a more dynamic distribution system that incorporates new technologies and significant quantities of DERs.

5. Reform Cost Allocation Methodologies

   States that are leaders in deploying DERs have experienced challenges where interconnection upgrade costs assessed to individual DERs have become prohibitively expensive. Studying facilities with common points of interconnection together and implementing cost sharing measures is one way of mitigating some of these upgrade costs developers, but such measures present other challenges and are no guarantee that DERs will continue to be deployed as more major bulk power system upgrades are triggered. This is because once a part of the distribution system reaches a certain level of DER penetration, interconnection upgrades are often still too expensive to share among interconnecting customers alone. Some states are beginning to recognize the need for advanced cost sharing methodologies that equitably share the costs of upgrading the electric power system across all customers who benefit from them, including ratepayers at large.

   States should take steps to effectively allocate costs in ways that support the cost-effective growth of DERs by adopting a cost sharing policy that distributes the costs across a more appropriate range of beneficiaries, properly recognizing that when constructing bulk power system upgrades of a certain magnitude, substantial benefits from constructing those upgrades may flow to customers other than to the DERs seeking to interconnect. Implementation of this approach should ideally be done in conjunction with reforms to distribution system planning procedures and the implementation of grid modernization measures to achieve the best results.

6. Invest in Grid Modernization Technologies that Support DER Integration

   State legislatures and regulatory bodies should direct and incentivize distribution companies to make investments in grid modernization technologies, software, and tools that help facilitate DER integration and allow DERs to provide the most value to the grid possible. While there are a myriad of grid modernization technologies and tools that should be considered, with respect to tools that facilitate DER integration and provide the most value to the electric grid and ratepayers, state regulatory bodies should direct utilities to make grid modernization investments in the following areas:

- Advanced distribution management system (DMS), supervisory control and data acquisition (SCADA) systems, and data management tools;
- Voltage and volt-ampere reactive optimization (VVO);
- Distributed energy management systems (DERMS); and
- Hosting capacity analyses and maps.

7. Reduce Unnecessary Barriers to Interconnection

Interconnection standards and procedures are constantly needing to evolve as new technological solutions emerge and experience is gained. Some key areas of innovation to ease the process by which DERs are physically interconnected to the electric grid include:

- Increasing transparency of targeted grid information by establishing open and transparent interconnection queues, fees, and equipment costs;
- Adopting alternative solutions to Direct Transfer Trip (DTT);
- Adopting technical standards;
- Allowing interconnecting customers to self-build system upgrades;
- Standardizing interconnection application processes; and
- Formally incorporating energy storage-related provisions into interconnection rules.

8. Improve Coordination with RTOs

As DERs continue to grow, there will need to be increased coordination with RTOs to ensure efficient and cost-effective DER project development. Currently the system construction timelines between RTOs, transmission owners, and distribution companies are not coordinated, which can easily derail project development. These issues are particularly problematic in Northeast states, but it is likely only a matter of time before they begin to surface in other regions too.

Some of the exacerbating factors that developers face include:

- Lack of clarity regarding whether a distribution line to which a facility is interconnecting is FERC jurisdictional or is subject to state level interconnection rules;
- Lengthy transmission level impact studies (and upgrades) being triggered that do not feature or align in state jurisdictional interconnection procedures; and
- No clear authority to address certain cross-jurisdictional issues.

As traditional, utility-driven, planning practices are outpaced, new planning approaches must be collaborative and flexible enough to grow with a quickly changing grid. It is critical to balance transmission level upgrades, which are extremely time consuming and expensive, with distribution level upgrades that cannot proceed without the former being complete. Joint planning between RTOs and utilities is vital to ensure clean energy is brought online seamlessly at both the distribution and transmission level. This can be supported by the following:

- Establishing collaborative stakeholder forums;

- Developing multi-jurisdictional roadmaps; and
- Clarifying issues pertaining to federal vs. state jurisdiction.

While each of the recommendations in this paper are critical to success, it is important to underscore how interrelated these actions are. It is necessary for stakeholders to think holistically about these topics and ensure that activities such as establishing integrated distribution system planning processes, realigning utility incentive frameworks, deploying and funding grid modernization technologies, and adopting interconnection process reforms are performed in a coordinated manner. The states that have been most successful in these areas to date have all taken such an approach and have recognized that these changes require an ongoing, iterative process to achieve the desired results.

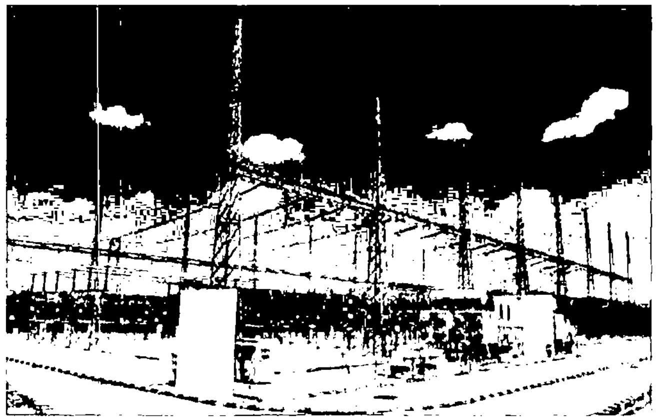
By adopting the recommendations in this paper, states can take significant steps towards creating an electric grid that effectively integrates DERs in the most optimal manner possible, maximizing their value to the grid and consumers in the process. By taking these steps, states can reduce operational and capital expenses associated with building and maintaining the distribution system, expand consumer options, achieve clean energy and climate mandates, spur massive amounts of local economic development, improve reliability and power quality, and create opportunities to improve the resilience of the electric grid.

I. Introduction

The United States' electric grid is an incredible feat of engineering. It traditionally consists of a centralized power source delivering electricity one-way and often over long distances through a complex web of increasingly smaller electrical lines, then finally terminating at the site of an end-use consumer of the electricity. While this centralized design was created for the sole purpose of providing reliable, safe, one-directional energy to utility residential, commercial, and industrial end-users, utilities now find themselves dealing with the need to upgrade aging grid infrastructure to meet changing electric load profiles resulting from electrification of the transportation and building sectors, meet changing customer demands, and incorporate new distributed forms of generation and storage. As the country races to meet state and federal mandates to significantly decrease greenhouse gas emissions over the next decade and beyond, the transition to a clean energy economy has become of critical importance. Additionally, the introduction of these new technologies is expanding customer options and leading to electric customers that are more engaged, informed, and aware of their energy usage than ever before. Consequently, the need to rapidly increase the volume of distributed energy resources (DERs) on the grid and ramp down the production of fossil fuels necessitates massive changes to the existing grid, utility planning, and utility incentive frameworks.

Over the last decade or so, outdated regulatory frameworks, lack of integrated planning, and misaligned utility incentives have led to a perpetual bottleneck in the process of designing and interconnecting DER systems to the grid. As a result, the interconnection process is often overly time consuming, high-cost, and high-risk, with extreme volatility in return on investment to those funding DER grid integration.

To rapidly deploy DERs and unlock all the benefits which they provide, it is necessary to transform the current interconnection process into a relatively quick, easy, and straightforward procedure using the latest technological advancements and cost allocation mechanisms emerging from booming DER markets all over the country. Additionally, new grid modernization technologies must be deployed in tandem to permit these new resources to be utilized optimally from both a grid operations and cost/benefit perspective. Deploying these new technologies and policy frameworks in coordination with regulatory reform and new rate designs will send proper price signals to DERs resulting in a higher penetration of DERs. This in turn will lead to clean energy and decarbonization goals being met in a way that promotes equity and provides the most value to ratepayers.



II. Guiding Principles

Reforming the processes for integrating DERs into the electric grid requires a coordinated effort among legislators, regulators, utilities, the clean energy industry, and other stakeholders. Applying the following guiding principles can help create a framework that will drive innovation and enable the realization of the shared objectives of all parties.

1. <u>Value of DERs</u>: To make the changes necessary to meet federal and state decarbonization goals, all parties need to agree they are working toward a future economy that is predominantly powered

by clean and distributed energy resources. This starts with accepting the critical role and value that DERs can play in enabling a clean, resilient, reliable, equitable, and affordable energy ecosystem and the unique benefits they provide. While new technologies, regulatory frameworks, and markets will likely need to be implemented to take full advantage of the net benefits of DERs, they can provide significant value to the grid, ratepayers, and society at large today. Accordingly, there should be no delay in deploying them as rapidly as possible. Waiting to deploy these critical resources until the perfect regulatory framework is in place will result in the loss of potential benefits such as avoided costs and emissions. Policymakers, regulators, and utilities must recognize the value these resources can provide now and take steps to deploy them accordingly, all while moving in parallel to develop the new regulatory frameworks that will permit them to be optimized and provide the greatest value.

2. DER-Based System Planning: A high-DER future cannot happen unless utilities undertake a coordinated planning process that targets the correct goals. Many such integrated planning processes are now being implemented across the country, but they could be improved by accounting for DER hosting capacity needs, accounting for projected load growth due to electrification, and by allowing for a wider range of affected parties to weigh in as part of the planning process.

3. Realigning Utility Incentives: The entire utility regulatory compact is built on financial incentives for utilities, and the shift to a grid with more DERs requires that financial incentives for utilities need to be aligned with the goals of the state (e.g., decarbonization). Instead of only incentivizing utilities to build centralized generation and transmission and distribution infrastructure to meet reliability needs and grow their rate base, utilities should also be incentivized to make investments that facilitate and directly support decarbonization and electrification objectives, such as the addition of more decentralized sources of power generation or demand management to the grid.

4. Advanced Enabling Technology and Information Transparency: Information is at the core of a smooth and cost-effective interconnection process. Utilities must move towards providing transparent, granular, and updated information about every location on the grid so that they can adequately plan for future needs and customers can cost-effectively site DERs and provide system benefits now and in the future. The authorization by policymakers and regulators of utility investments into grid modernization technologies that improve visibility into the operation of their systems, support their management of DERs, and assist them in developing tools such as hosting capacity maps, are instrumental in meeting these objectives.

5. Cost Effective Decarbonization for All: The environmental and health impacts of power plant siting have disproportionately impacted underserved and underrepresented communities across the country. To improve our air quality and public health for all communities, we will need to ensure costs and benefits are shared equitably among all grid participants who benefit from system upgrades, which will require re-thinking established policies regarding cost allocation associated with these upgrades. Programs that support the growth of DERs also must ensure that all customers have access to affordable DER solutions of their own and that they are not simply available to those who can afford them. Rules and guidelines should always drive toward simple, feasible solutions that keep costs low for all stakeholders, and in particular, underserved communities.

6. Multi-Level Stakeholder Engagement and Coordination: Any successful transition is based on a wide degree of coordination, both within and outside of the regulatory environment. Coordination is needed between wholesale and retail policies and procedures, and among RTOs, utilities, state agencies, DER

providers, and all other electric grid stakeholders. This will need to be accomplished with executive oversight, interagency coordination between federal, state, and local regulatory bodies, intra-utility coordination between policy and technical staff, and outreach to other key stakeholders such as consumer advocates, environmental advocates, and local officials.

7. Resilience: Interconnection reform and grid modernization must ensure that the grid is built for a changing climate. While utility infrastructure and planning efforts should take such climate impacts into account, the ability for DERs to provide resilience benefits should also be incorporated into utility planning and programs. There are numerous examples in recent years of regions impacted by what were likely natural events enhanced by the effects of climate change that took a significant amount of time to recover (e.g., Hurricane Maria in Puerto Rico in 2017) because their electric grids were not resilient enough to withstand the impact. The value of resilience should be identified and prioritized and technologies like energy storage should be incorporated into existing rules, programs, and planning to help mitigate the impact of such events in the future.

III. Fundamental DER Challenges

While many states are driving toward faster, more cost-effective interconnection processes, inconsistencies across markets make it challenging to rapidly deploy DERs, even when those resources can save ratepayers millions of dollars per year[2]. At the most fundamental level, the interconnection landscape is challenging because the stakeholders involved have competing priorities that either create substantial friction in the process or impede progress altogether. The following is a list of the most significant challenges facing DER deployment at present.

1. Lack of Comprehensive Guidance in DER Legislation: The legislative process is not designed to (and should not) address the technical complexities of interconnection. Legislation also may not include the full tool set that state regulators, utilities, and developers need to ensure clean energy projects progress to rapid DER integration. However, without clear legislative direction setting forth objectives regarding system planning, siting, and grid modernization, it is likely that inefficiencies and lack of clear prioritization between regulators, utilities, and stakeholders will continue to create bottlenecks for DER integration and interconnection process and will threaten attainment of state decarbonization and clean energy deployment goals.

2. Insufficient DER Regulatory Resources: States and their regulatory agencies may not have access to the necessary resources and technical expertise needed to administer and regulate a widespread transition to DERs. This may lead to an imbalance in not only in the position of regulators relative to the utilities they regulate, but also with respect to how all other affected stakeholders can participate and respond to utility proposals related to system planning, investments in the electric grid, and modifications to standards or other practices.

3. Non-Existent or Limited Utility Incentive Structure to Support DER Deployment: Utilities typically do not have a financial incentive to deploy and facilitate DERs and generally do not earn a return on the

2 Comprehensive modeling carried out by Vibrant Clean Energy and Local Solar for All Coalition has demonstrated that to achieve President Biden's climate and equity goals at the lowest cost, it will be necessary for the United States to deploy at least 103 gigawatts (GW) of distributed solar and 137 GW of distributed energy storage by 2030. Scaling up these resources was also shown to enable the deployment of 579 GW of utility-scale solar and 442 GW of wind. It was also shown to save all ratepayers over $109 billion by 2030 compared to deploying only utility-scale renewables as well as lead to the creation of 1.2 million new jobs by 2030.

infrastructure built to interconnect projects. In many cases, utilities may lose revenue and experience higher operational complexities with higher DER penetration. This contributes to situations where utilities are often significantly understaffed relative to what is required to process interconnection requests in a timely manner, slowing the process for all involved and increasing the cost of DER implementation.

4. Lack of Coordinated Systems Planning: Interconnection is just one aspect of DER deployment that fits within the broader scope of comprehensive integrated grid planning. Many states undertake these interrelated efforts in separate silos with limited opportunity for stakeholder input on utility planning processes. Additionally, the majority of states do not engage in distribution planning with a goal of increasing DER adoption. A high DER electric system will also have an impact on the transmission system, which necessitates the collaboration and coordination of a wider array of affected system owners (such as transmission owners and regional transmission operators). The lack of coordinated and optimized planning processes that account for the continued deployment of DERs and the electrification of the transportation and building sectors can lead to increased costs for both DER developers and customers.

5. Inappropriate Cost Allocation Methodologies that Impede Development: Traditionally, distribution and transmission system upgrade costs necessary to facilitate the interconnection of a generation facility have been assessed to and paid for by the facility owner. Cost causation remains an appropriate regulatory tool in many contexts and should apply to upgrades required to interconnect DERs that clearly only benefit the interconnecting customer. However, it should not be applied to all distribution system upgrades associated with DERs, particularly when those upgrades provide benefits to customers other than the interconnecting customers themselves. In the DER industry's nascent years, projects were able to find sites with existing capacity which did not require unfinanceable grid upgrade costs, but as DER penetration levels increase, the type of upgrades required to interconnect facilities are becoming much more significant investments. Some of these investments include things such as substation transformers or the reconductoring of transmission or distribution lines that serve large numbers of customers. While interconnecting DERs may initially trigger the need for these investments, the nature and scope of the investments in question requires a re-examination of whether it is appropriate to continue the application of the cost causation principle[3] to all upgrades and whether these costs should be allocated amongst other types of customers that receive benefits from the upgrades as well.

6. Lack of Transparent, Accurate, and Timely Grid Data: Transparency and data are fundamental to economic and operational efficiency. Unfortunately, DER developers today very often lack the necessary information around feeder, circuit, and substation capacities as well as sufficient market signals to make informed business decisions. This leads to massive inefficiencies in the interconnection application and study process as developers are competing for the lowest cost interconnections based on limited information, which in turn leads to them submitting speculative applications to gather the information necessary to make investment decisions. This results in unnecessary time and money spent by developers and utilities studying whether many sites are feasible when upfront access to information could have disqualified the site(s) without the need for an application or study in the first place. In some cases, this is simply a matter of the utilities not

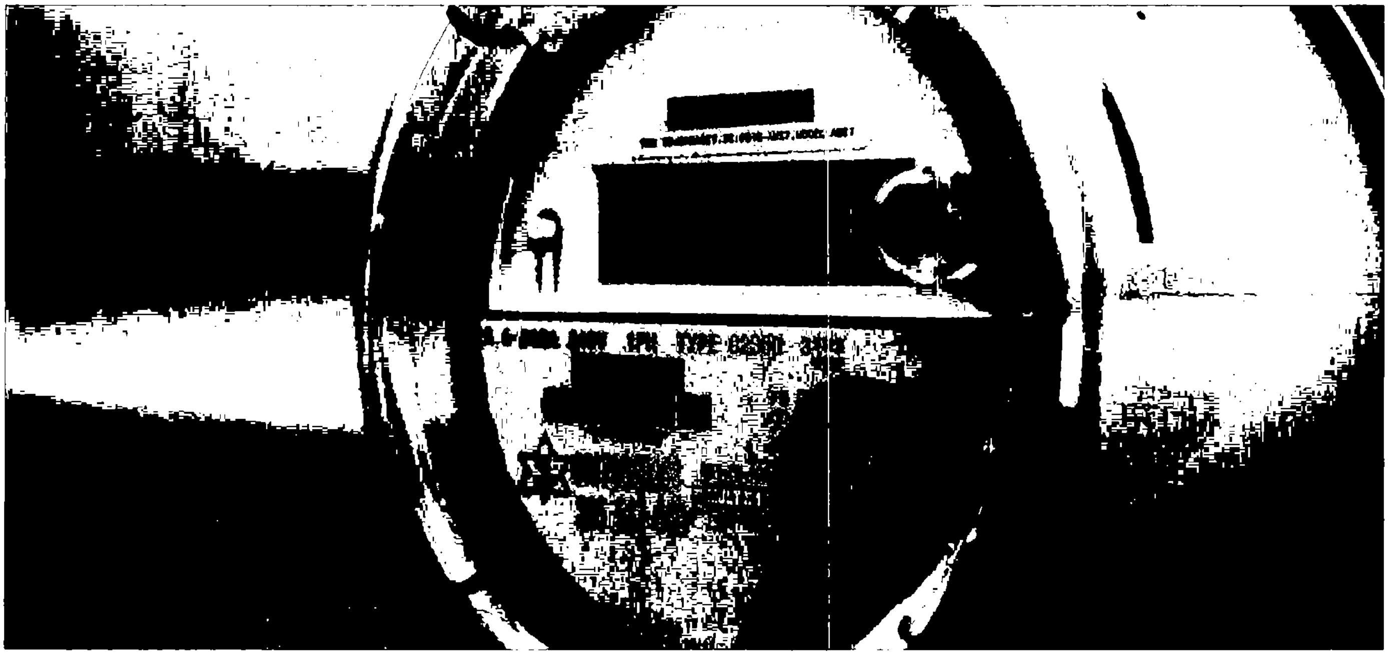
3 The application of the cost causation principle generally requires the entity determined to be responsible for the cost to be incurred to be responsible for payment of the costs (i.e. cost responsibility follows cost incurrence), but does not necessarily take into account the benefits that may flow to other entities as a result.

providing data to which they already have access. In many jurisdictions though, it is also the case that the utility does not have this information themselves as they have not made (or been authorized to make) investments to modernize their distribution system that could facilitate the collection of this and other useful data.

7. Lack of Uniform Standards and Difficulty of Integrating New Concepts: Utilities often rely on different technical standards when studying interconnection applications[4]. This leads to inefficiencies, additional costs, and confusion amongst developers that operate across different state markets (and sometimes even within a single market). Additionally, it takes time and experience for utilities to become comfortable with new mechanisms to accelerate DER deployment and rely on new technologies, such as energy storage. While it is true that utilities operate their distribution system differently and may have unique constraints, this results in both a lack of clarity around applicable rules as well as inconsistencies in standards, rules, and procedures that apply in different jurisdictions, which can unnecessarily add expense and time to the interconnection process and make it more challenging to integrate DERs.

8. Lack of Coordination with Other Affected System Operators: A multi-directional power grid necessitates coordination with other entities on both the distribution and transmission planning sides. For example, the lack of joint planning and coordinated interconnection processes between states, distribution utilities, and affected systems like those operated by Regional Transmission Operators (RTOs) often leads to misunderstandings in the distribution versus transmission jurisdiction of DER projects, costing valuable time and resources.

IV. The DER Vision



We envision communities in which the interconnection of DERs is much like that of other industries that have experienced significant streamlining in recent decades (e.g., phone, internet, entertainment, travel, etc.)

4 This may even be the case within the same state as the interconnection procedures for some utilities may not fall under the jurisdiction of the state utility commission (e.g. municipal or co-op utilities) or may fall under separate RTOs, which may have differing procedures that could impact projects at the distribution level.

reflective of advanced technological achievements of the 21st century. For example, only decades ago, every consumer had a landline telephone, and the internet did not exist. In the information age, far fewer people own a traditional landline phone in their home. Most people around the world communicate via a cell phone which they received in a 30-minute sign-up process at the nearest cell phone provider store. Most Americans also own a home computer and internet service, which can typically be set up remotely by calling or logging into an internet provider's website, providing them with access to a 24/7 global network of information, technology, and entertainment in little to no time. This same type of rapid transformation to a high DER future is achievable and must be urgently carried out to successfully meet changing consumer demands and achieve critically important decarbonization mandates and objectives.

Imagine that a DER customer requests new service or interconnection behind their existing meter and can log onto the utility website, enter in the proposed site address for a solar facility, and access key details on the proposed interconnection point immediately. They can view the feeder and substation current capacity in real-time and have the option to effectively size the system within the confines of the current grid, evaluate non-wires alternatives, or discern the potential costs to upgrade the feeder for a larger project if desired. They can enter all equipment to be used, as well as schedule a site visit for a utility engineer to inspect the site and provide the construction upgrade date. All system testing can be done remotely, with the entire process taking a fraction of the time and the cost of current interconnection processes. While such a streamlined process does not exist today, it is not inconceivable to imagine a point in the near future where the information and procedures necessary are available to make it a reality, however, it is necessary for a whole suite of regulatory changes to occur before this can become reality.

As highlighted in Section III above, there are many challenges to reaching a future where DERs are seamlessly integrated into the electric grid and can provide the full suite of benefits to customers of which they are capable. To accomplish these two objectives and reach a future in which our vision is realized, the following will need to be pursued by policymakers, regulators, and utilities:

- Traditional distribution and system planning models must be revisited;
- Utility incentive structures must be revised;
- New technologies will need to be deployed on the electric grid in significant quantities;
- Existing technical standards will need to be re-examined and new ones adopted
- New cost allocation frameworks will need to be designed and approved; and
- Clear direction and proper resources will need to be provided to regulatory bodies and utilities by policymakers.

The technologies and solutions are available today to accomplish these objectives and many US states have already taken innovative approaches to addressing each of these topics. It is important to note though that achieving these objectives will require coordination of these topic areas and that the states that have made the most progress to date have recognized this and organized their efforts accordingly. The roadmap below provides recommendations, resources, and case studies that are designed to guide policymakers, regulators, and utilities as they plan for the future. By taking the steps outlined in the roadmap, we can collectively work together to decarbonize the grid and unlock the full potential of DERs to benefit all stakeholders.

V. The DER Integration Roadmap

The following roadmap aims to create a common path for all DER stakeholders to address the common challenges listed above and achieve a future in which DERs are fully integrated into the electric grid. Wherever possible, the roadmap offers specific recommendations gained from best practice methodologies in leading DER states and provides resources for interested parties to perform a deeper dive into each topic covered.

1. Establish Clear DER Integration Objectives Through Legislative Action

There is often a substantial disconnect between renewable legislation, such as achieving 100% renewables by a date certain, and the ability to translate that mandate into efficient and clear directives for state agencies, utilities, and clean energy developers to achieve that goal. Without strong, comprehensive direction set by legislation for each aspect of the DER transition process, regulatory agencies may not be able to establish processes for utilities to efficiently manage a transition to a high DER future.

Regulatory bodies such as public utility commissions are tasked with ensuring reliable, safe, and cost-effective electric service. Such regulatory bodies must balance the interests of utilities and consumers and strive to make decisions that are "consistent with the public interest." These regulatory bodies are often quasi-judicial and are less likely to stake out major policy positions unless they have been clearly articulated by the state legislature. This quasi-judicial role and tension between public and private interests creates an environment where regulators are often disinclined to expand upon conservative interpretations of legislative intent. State legislatures must enact clear policy that alleviates the inherent tension between a state regulatory body's traditional role of balancing utility and public interests and instead allows for more discretion in the setting of rates and regulation to fulfill clean energy, grid modernization, and decarbonization goals.

Recommendations

State legislatures should enact laws that provide state regulatory agencies with the requisite authority, direction, and resources to address challenges related to DER integration. Additionally, while the federal government cannot regulate distribution lines and directly set state policy, it can provide incentives and support to help states expand their own resources as well as to carry out the expensive stakeholder processes needed to advance distribution grids and grid planning to the 21st century. Federal assistance on these topics may or may not require authorizing legislation, but likely could be provided by the Department of Energy (DOE) directly or acting in conjunction with other organizations.

A. Direct regulatory agencies to prioritize decarbonization

State regulatory bodies have traditionally been tasked with ensuring safety, security, reliability, and affordability with respect to utility operations and rate design. As the electric grid that utilities operate becomes a key factor of achieving decarbonization mandates, it is critical that mission statements for state regulatory agencies are expanded to include decarbonization as another of their core functions. In some cases, the state regulatory body may take this task on themselves without a specific legislative directive to do so. However, clear statutory direction on this topic provided by state legislatures can play an enormous role in reshaping the mission of state regulatory bodies as it can either force them to consider issues through a lens they may not have otherwise considered and/or provide them with the necessary cover to make decisions that are supportive of decarbonization requirements.

Case Study: An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy

A good example of a state legislature directing a state regulatory agency to prioritize decarbonization comes from An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, which was signed into law in March 2021, and establishes a new mission statement for the Massachusetts Department of Public Utilities, which reads as follows (emphasis added):

> Section 1A. **In discharging its responsibilities under this chapter and chapter 164, the department shall, with respect to itself and the entities it regulates, prioritize** safety, security, reliability of service, affordability, equity and **reductions in greenhouse gas emissions to meet statewide greenhouse gas emission limits and sublimits established pursuant to chapter 21N.**

This legislation clearly ties the Department's mission to the Commonwealth's Global Warming Solutions Act greenhouse gas reduction requirements, ensuring that achieving such reductions must be a priority for the Department in all future decisions it makes, assigning it equal weight amongst more traditional regulatory responsibilities such as safety, security, reliability, affordability, and equity.

Chapter 8 of the Acts of 2021 (Section 15)

B. Communicate interconnection and grid planning needs of programs

Meeting ambitious clean energy targets requires forethought and direction with respect to grid planning and interconnection. Unfortunately, there are few examples of state legislation establishing DG programs (incentives, net metering, etc.) being accompanied with clear guidance on establishing interconnection standards to achieve the goals of the programs. This has led to disconnects between programmatic objectives and the process that is utilized to meet them. Accordingly, the importance of including provisions related to interconnection and grid planning in energy legislation has become clear. Absent such, the clean energy targets established in statute will often not be feasible to achieve.

In many cases, it may be necessary for state legislatures to provide direction to state regulatory agencies and utilities by enacting comprehensive interconnection legislation in conjunction with the establishment of clean energy or climate targets. For example, if a state legislature directs the establishment or expansion of an existing program to support distributed energy resources, it may be wise to accompany that with a directive to the state regulatory agency to examine targeted topics related to interconnection to determine what regulatory reforms to interconnection or system planning will be necessary to achieve the objectives set forth by the legislation. At minimum such language should include a time-bound grid planning process that will provide policymakers and stakeholders a robust view of how the state can meet clean energy targets, the initiation of interconnection reforms, and the establishment of planning and interconnection focused working groups.

Case Study: Illinois Clean Energy and Equitable Jobs Act

A good recent example of direction on interconnection related policies being provided in conjunction with clean energy deployment mandates comes from Illinois, which recently enacted the Clean Energy and Equitable Jobs Act. Among the major clean energy provisions contained in the bill is a section directing the Illinois Commerce Commission (ICC) to establish an Interconnection Working Group within 90 days of the effective date of the Act. The Interconnection Working Group is required to report to the ICC every six months on recommended improvements to interconnection rules, tariffs, and policies and is specifically tasked with examining at least the following topics:

- Cost and best-available technology for interconnection and metering, including standardization and publication of typical costs;
- transparency, accuracy, and use of a distribution interconnection queue and hosting capacity maps;
- avoiding distribution system upgrades through the use of advanced inverter functions;
- interconnection queue management and timeline enforcement;
- benefits and challenges associated with group studies and cost sharing;
- minimum requirements for interconnection applications and application queue management procedures;
- process and customer service for customers adopting DERs, including energy storage;
- options for metering DER, including energy storage;
- interconnection of new technologies including smart inverters and energy storage;
- collecting, sharing, and examining data on level 1 interconnection costs to inform standardized cost of level 1 interconnections; and
- such other technical, policy, and tariff issues related to and affecting interconnection performance and customer service as determined by the working group.

Clean Energy and Equitable Jobs Act (Public Act 102-0662) see p. 745-748 of PDF
ICC Interconnection Working Group

C. Provide regulatory agencies with adequate resources

Most state level energy regulatory agencies have budgets set by state legislatures through normal budget appropriation procedures. However, unlike many other agencies, which are funded with taxpayer dollars, state energy regulatory agencies are typically funded through assessments, fees, and/or taxes on the utilities over which they have jurisdiction, which may or may not be recovered through rates to end-use customers. Regardless of how budget needs are met, the fact is that state legislatures have considerable ability to influence the activities of a state regulatory agency through the budgeting process.

Complex DER programs are administratively burdensome for regulatory agencies and will require commensurate resources to effectively manage. Overburdened state regulatory bodies will almost certainly need additional funding to hire more staff and dedicated funding to hire moderators and ombudspersons to act as mediators between industry, utilities, and other stakeholders. It is highly important that regulatory agencies be brought in during the legislative process so they can clearly communicate financial and other needs for program development and implementation.

Case Study: Illinois Clean Energy and Equitable Jobs Act

Once again, Illinois provides a good recent example, as the Clean Energy and Equitable Jobs Act specifically directs the ICC to establish a Division of Integrated Distribution Planning, which must have a staff of at least 13 individuals and will almost certainly play a key role in helping plan for the integration of DERs and ensure that decarbonization goals are met. While this language does not include a budget appropriation for this new staffing requirement, it does articulate a clear set of objectives and provides direction for the ICC on what level of resources need to be dedicated to meeting those objectives. Actual budgeting for the staffing resources will presumably be addressed through the state budgeting and appropriations process, which will be conducted separately from the establishment of the policy priorities in this particular act.

Sec. 16-108.19. Division of Integrated Distribution Planning.

(a) The Commission shall establish the Division of Integrated Distribution Planning within the Bureau of Public Utilities. The Division shall be staffed by no less than 13 professionals, including engineers, rate analysts, accountants, policy analysts, utility research and analysis analysts, cybersecurity analysts, informational technology specialists, and lawyers to review and evaluate Integrated Grid Plans, updates to Integrated Grid Plans, audits, and other duties as assigned by the Chief of the Public Utilities Bureau.

Clean Energy and Equitable Jobs Act (Public Act 102-0662) see p. 853 of PDF

2. Expand Resources Available to State Regulators

State regulatory bodies and other state agencies often lack the expertise to create technical guidelines for utilities to aid in the implementation of new technologies (e.g. for advanced inverter or storage systems). Utilities can also be slow to create new policies and procedures for specific technology adoption even after state incentive programs calling for new technology advancement have been published. This leads to situations where the utilities drive the conversation at the state level and may take longer than necessary to implement essential changes.

Recommendations

Every state has a unique mix of energy resources, grid capability, regulation, and ratemaking procedures and rules. To ensure utilities are proactively planning for a substantial increase in DER and accompanying advanced technology integration like storage battery systems, state regulatory bodies must be empowered to have the same level of technical expertise as utility staff when coordinating with stakeholders on the best path forward to high DER integration. This may require augmenting staffing at the state regulatory body or increasing reliance on consultants, but it also requires that state regulatory bodies have the necessary oversight authority to ensure that utilities are held to standards the state regulatory body establishes. We strongly urge the following:

A. Increase Technical, Policy, and Mediation Resources for State Regulators

i. Expand Staff and Consultant Resources

Hiring engineers as regulatory agency staff or consulting firms with relevant experience can guide regulatory agencies in better decision making and coordination with utilities. Having access to on-staff or consultant technical expertise in topics such as distribution system planning, grid modernization, and interconnection allows regulatory agencies to be on a more even footing with utilities and to review technical procedures and policies more effectively utilities propose.

While there are too many examples of for-profit consultant organizations with expertise that could be hired to aid state regulatory bodies and policymakers to list here, the following organizations represent a non-comprehensive list of non-profit organizations with significant expertise in these topic areas that may be able to provide assistance to regulatory bodies at little or no cost.

Interstate Renewable Energy Council (IREC)

IREC is a non-profit organization whose mission is to "build the foundation for the rapid adoption of clean energy and energy efficiency to benefit people, the economy, and our planet." IREC has provided input on interconnection policies in over 35 states and employs experts in matters relating to solar, energy efficiency, grid modernization, energy storage, electric vehicle infrastructure, and interconnection. In addition to allocating resources directly into state level policy proceedings, IREC has published some extremely helpful resources for policymakers, regulators, and utilities that are available on their website, including model interconnection procedures, which are free to download and are updated fairly regularly.

National Regulatory Research Institute (NRRI)

NRRI was founded in 1976 by NARUC and serves as a research arm to NARUC and its members (i.e. the utility regulatory commissions of the fifty states and the District of Columbia in the United States). NRRI's mission is "to serve state utility regulators by producing and disseminating relevant, high-quality research that provides the analytical framework and practical tools necessary to improve their public interest decision-making."

Regulatory Assistance Project (RAP)

RAP is a non-profit, non-partisan organization facilitating clean power market transitions in top international markets including the US. They employ a staff of experts whose work focuses on topics such as climate and public health, distributed energy resources, energy efficiency and demand response, energy resource planning, grid scale renewables, power markets and reliability, pricing and rate design, and regulation and governance.

Smart Electric Power Alliance (SEPA)

SEPA is a non-profit organization with over 1,000 members that envisions a carbon-free energy system by 2050. Over 700 of its members are utilities, but state regulatory bodies and certain state energy offices are automatically eligible for membership. SEPA produces educational resources on relevant topics such as utility regulatory and business innovation, grid integration, and electrification. They also establish working groups and regularly sponsor events and conferences.

ii. Establish Technical and/or Policy Working Groups Led or Monitored by Staff

An extremely effective method of maintaining regulatory flexibility and driving consensus on technical matters that has been implemented by many states has been the creation of standing technical and/or policy interconnection working groups. Such groups establish a forum for the exchange of ideas and information between utilities, industry, and other stakeholders and are often facilitated by policymakers and regulators. They allow for interconnection processes to evolve without the need for formal regulatory or tariff revisions, but can also identify when more major changes such as these are required and bring recommendations to regulators. They can also help foster better relationships between utilities and industry as technical and policy experts come together on a regular basis to find common ground on issues as they emerge.

Case Study: New York Interconnection Technical and Policy Working Groups

In 2016, the New York Department of Public Service (DPS) established two separate working groups, the Interconnection Technical Working Group (ITWG) and the Interconnection Policy Working Group (IPWG). These groups were established through internal recommendations and their work has since been formally recognized by the state commission in interconnection related orders.

The goal of the ITWG is "to identify, discuss and resolve technical barriers and challenges associated with [the] DER interconnection process and the Standardized Interconnection Requirements (SIR) in New York State in an efficient and effective manner." It is co-chaired by the DPS and the New York State Energy Research and Development Authority (NYSERDA) and utilizes Pterra, a third party engineering firm, to perform technical analysis and support to achieve resolution on key technical issues. The ITWG also has representatives from the New York Power Authority (NYPA) and the New York Independent System Operator (NYISO) as well as primary and secondary representatives from each of the joint utilities, a primary representative from the Long Island Power Authority (LIPA) and/or PSEG Long Island (PSEG-LI), and 5-7 primary representatives from the DG industry (with a single designated liaison). Like the TSRG in Massachusetts, the ITWG meets regularly (usually monthly) and is tasked with reaching consensus on substantive decisions regarding technical issues. Also like the TSRG, non-members may attend meetings, but may only engage in discussions if they have been invited to present or speak as a subject matter expert.

The IPWG's purpose is to explore non-technical issues related to the processes and policies relevant to the interconnection of DERs in New York (e.g., queue management, cost sharing, etc.). Like the ITWG, it is also co-chaired by the DPS and NYSERDA and has a similar composition. It also meets regularly (typically once per month), has similar organizational rules to the ITWG, and has been very successful in implementing a variety of incremental solutions to interconnection policy related matters since its inception, which have helped to establish New York as a leader in interconnection policy.

Case Study: Massachusetts Technical Standards Review Group

In January 2012, the Massachusetts DPU issued D.P.U. 11-75-A, which directed the establishment of a Distributed Generation Working Group tasked with investigating interconnection related issues and reaching a consensus on recommended changes to interconnection procedures. Among the recommendations of the DG Working Group that were later adopted by the DPU was the establishment of a Technical Standards Review Group (TSRG), which since its inception has been an extremely effective body in resolving technical implementation matters without the need for protracted and drawn out contested processes at the DPU.

The TSRG consists of seven members, which includes four utility representatives, one solar representative, one combined heat and power representative, and one government/customer representative. The Department of Energy Resources (DOER) also participates in the TSRG and the DPU serves as an ex officio member. The TSRG meets semi-annually (usually quarterly) and discusses issues related to the establishment of common technical standards by the Massachusetts utilities. The utilities have the absolute right to make modifications to technical standards but must explain such modifications to non-utility members. Members of the public are permitted to observe meetings but may not be able to raise issues directly unless they are invited or do so via an official member.

Case Study: Connecticut Interconnection Technical and Policy Working Groups

Building on the models advanced by Massachusetts and New York, in November 2020, the Connecticut Public Utilities Regulatory Authority (PURA) issued a decision adopting the recommendations of a an interconnection working group report[5] that both an interconnection Policy Working Group (PWG) and Technical Working Group (TWG) be established. Since their initial establishment in March 2021, the groups have each met monthly and have similar membership compositions and mission statements to their counterparts in New York.

ii. Utilize Third-party Moderators/Facilitators

Another important resource for regulatory and policy agencies can be third-party moderators. Oftentimes public agencies can be effective in convening policy discussions, but may face challenges in effectively moderating such conversations, particularly if they are going to be required to make a final decision on a particular matter. Effective moderators can help drive diverse stakeholders to consensus and can achieve better technical and policy outcomes.

The following are a handful of examples of situations where third-party moderators/facilitators played a critical role in advancing the objectives of a technical proceeding conducted by a state regulatory agency.

Case Study: California Rule 21 Working Group

In July 2017, the California Public Utilities Commission (CPUC) issued an order instituting a rulemaking to consider a series of refinements to the interconnection of DERs under Electric Tariff Rule 21. In a subsequent scoping ruling,[6] the CPUC established a list of 28 issues to be divided amongst six working groups. GridWorks, a consulting firm with expertise in facilitating and fostering connections between decarbonization advocates, energy providers, and utility operators, was designated as the facilitator for a portion of this work. GridWorks played a key role in structuring the process and developing the recommendations made by the respective working groups for which they provided facilitation services.

GridWorks Rule 21 Working Group 4 Website

Case Study: Massachusetts Distributed Generation Working Group

5 Referred to as the 100-Day Sprint Working Group Report.

6 This was later amended the following year through the issuance of a new scoping ruling.

In January 2012, the Massachusetts DPU issued D.P.U. 11-75-A, which directed the establishment of a Distributed Generation Working Group tasked with investigating interconnection related issues and reaching a consensus on recommended changes to interconnection procedures. As part of this and a subsequent order, the DPU directed the Massachusetts distribution companies to work with DOER to develop and then jointly issue a request for proposals RFP for an independent facilitator to manage the Working Group. The RFP was subsequently approved and Dr. Jonathan Raab of Raab Associates, Ltd. was selected to facilitate and lead the Working Group. Over the next four months, the facilitation of the Working Group was completed with the filing of a final report followed shortly thereafter by consensus edits to the statewide model interconnection tariff. The majority of the recommendations of the report and edits to the interconnection tariff were later approved by the DPU with the issuance of D.P.U. 11-75-E. This all serves as an excellent example of a successful facilitation process that brought together parties, resolved issues expeditiously, and avoided what could have been a protracted contested proceeding before the DPU.

Case Study: Great Plains Institute

One final example of successful facilitation of state regulatory processes is the use of the Great Plains Institute in Minnesota. The Great Plains Institute is an organization that brokers agreements in the energy space, working on topics such as carbon management, communities, energy efficiency, electricity, and transportation and fuels. Over the years it has facilitated many utility and regulatory stakeholder processes in Minnesota such as: the e21 Initiative, Solar Pathways, and innovative utility programs involving electric vehicles, time-of-use rates, and more.

iii. Create an Interconnection Ombudsperson Role

One other effective tool that has been employed by states is to create an interconnection ombudsperson role at state regulatory agencies, which can facilitate the efficient and fair resolution of disputes between parties and through which more informal guidance can be provided to stakeholders. Establishing such a position within a regulatory body creates a single point of contact through which customers can obtain information and seek advice on the proper steps to take to resolve issues and can also fulfill a role of mediating disputes between parties (e.g., utilities and interconnecting customers), helping to avoid *ex parte* communications with agency staff as well as formal complaints being filed with a commission for adjudication. An ombudsperson can also monitor trends and recommend actions that a commission may take to resolve policy more proactively and/or technical issues that are arising.

Case Study: California Rule 21 Interconnection Tariff

Section K of California's Rule 21 interconnection tariff includes provisions for resolution of interconnection disputes. For disputes regarding missed timelines on the part of the utilities, the tariff requires that each utility designate an ombudsman. If an ombudsman is unable to resolve a dispute with an interconnecting customer within 10 business days, the customer may either contact the Consumer Affairs Branch at the CPUC or, upon mutual agreement with the utility, make a written request for mediation to the CPUC's Alternative Dispute Resolution Coordinator. The mediator assigned to such a matter will make attempts to schedule a mediation within 10 business days of receiving such a request.

Case Study: Massachusetts DG and Clean Energy Ombudsperson

As part of the Distributed Generation Working Group recommendations described above that were adopted by the DPU in 2013 with the issuance of D.P.U. 11-75-E, the DPU established an interconnection ombudsperson's role within the dispute resolution process on a trial basis. According to the DPU, the interconnection ombudsperson's role was to:

1. be easily accessible;
2. review written documentation from the good faith negotiation process;
3. conduct independent interviews and investigations as she deems necessary; and
4. offer independent problem-solving assistance.[7]

After a one-year pilot, the DPU recognized the establishment of the ombudsperson role as "an unqualified success" and extended the role indefinitely, permanently incorporating it into the state's standard DG Interconnection Tariff. Under the tariff, the role of the ombudsperson is to oversee an alternative dispute resolution process, through which an interconnecting customer can seek a facilitated dispute resolution if they believe the utility has violated a tariff provision, rule, or regulation, the issue has been raised to senior management at the utility, and they have attempted resolution for eight days or longer. Upon the alternative dispute resolution process being triggered, the ombudsperson will put forth a proposed resolution and if the parties do not agree, they may move to formal mediation and then a formal petition to the DPU for an adjudicatory proceeding, if necessary.

In 2019, in recognition of the "increase in energy policy initiatives that will influence and guide the [DPU]" the duties of the role were expanded with the issuance of D.P.U. 19-55-A, which renamed the position the DG and Clean Energy Ombudsperson.[8] This expanded role now includes responsibility for the following clean energy, climate change, and DG matters:

1. continuing the role and responsibilities of the interconnection ombudsperson;
2. overseeing or advising all such dockets, programs, and projects before the Department, in coordination with relevant Divisions within the Department;
3. managing all such public inquiries and complaints;
4. maintaining open communication with the electric distribution companies, stakeholders, and other government agencies, including enabling education and outreach;
5. supporting the Commission and Division of Regional and Federal Affairs as a contact and liaison for the Department on state, regional, and federal related issues;
6. assisting the Chief of Staff and Commission in addressing state consumer energy policies, updating state elected officials, explaining Department policies and practices, and providing information to support development of energy legislation and statutory reforms, and
7. assisting the Commission in the development of new policies or regulations.[9]

7 Massachusetts Department of Puablic Utilities, D.P.U. 11-75-E, at 30.

8 The position was also established as a standalone position within the DPU whereas previously the Interconnection Ombudsperson role was one of several responsibilities assigned to the Director of the Consumer Division.

9 Massachusetts Department of Public Utilities, D.P.U. 19-55-A, at 3-4.

Case Study: Minnesota Informal Complaint Dispute Resolution Process

While Minnesota does not have formal ombudsperson roles established at either the Minnesota Public Utilities Commission (MN PUC) or the utilities it regulates, it does have interconnection rules that contain a more informal dispute resolution process than most states permit. Under Section 5.3 of Minnesota's Distributed Energy Resources Interconnection Process (MN DIP), parties (either the utility or the interconnecting customer) may utilize the MN PUC's Consumer Affairs Office's informal complaint dispute resolution process to attempt to work through issues that arise before progressing to formal remediation or an adjudicatory process. The MN DIP spells out clear timelines and includes a process flow diagram that details each step of the process that is to be followed if the informal dispute resolution process is initiated.

Case Study: New York Interconnection Ombudspersons

In early 2016, management at both the DPS and NYSERDA established an interconnection ombudsperson role, appointing a staff member at each agency to facilitate queue management issues with utilities and developers. At the same time, each of the utility companies appointed ombudspersons within their companies to liaise with agency staff and developers. Since the establishment of these roles, they have served functions similar to those implemented in California and Massachusetts, namely, serving as mediators and identifying and facilitating policy development where appropriate.

Interconnection Ombudsman Website

B. Expand Accessibility to Stakeholder Forums

State agencies and utilities generally have online repositories containing all information pertaining to public proceedings, but this information is not always organized as well as it could be or as searchable as it could be. State agencies should consider how easily accessible this information is to the public and undertake reforms and/or direct the utilities to make certain information available as needed.

Another thing to consider is creating dedicated web pages related to topics such as interconnection, system planning, grid modernization, or DERs. This allows for information to be neatly organized in a single location so that stakeholders do not spend an inordinate amount of time searching through an online filing system to find information or important resources.

Lastly, a final recommendation is to ensure that public meetings have the option for attendees to participate remotely and that meetings be recorded and/or minutes be taken and posted publicly later for those that were unable to attend. One impact of the COVID-19 pandemic is that it accelerated the transition to public meetings being conducted remotely with greater regularity. This is a positive development and should be continued going forward.

The following is a non-comprehensive sampling of government and utility websites related to DER interconnection that are models to consider when organizing interconnection related information:

California

CPUC Rule 21 Interconnection Page
PG&E Rule 21 Interconnection Page
SCE Rule 21 Interconnection Page
SDG&E Rule 21 Interconnection Page

Massachusetts

Eversource DG, Interconnection, and Net Metering Page
MA DPU Interconnection Page
MA TSRG Page

Minnesota

MN PUC Interconnection Information Page

New York

NY ITWG Page
NY IPWG Page
New York Joint Utilities Webpage

C. Develop and Take Advantage of Federal Resources

To the extent such resources are available, state agencies, regulatory bodies, and utilities should seek out guidance and/or financial assistance from the federal government, particularly the Department of Energy (DOE) and the national labs, both of which employ staff who are often very knowledgeable on these topics and can be extremely valuable resources as state's explore solutions to policy related or technical issues.

To the extent they are not already doing so, DOE could consider providing block grants to state energy offices and regulatory agencies and performance-based incentives to utilities that can support distribution-level planning, equitable DER program development, and project development. For example, DOE could provide block grant funding to state agencies for program development with requirements for equitable cost-benefit sharing and can provide direct funding to utilities and projects for planning and implementation.

Additionally, the national labs have completed many reports directly focused on or closely related to topics such as distribution system planning, grid modernization, and interconnection, but could focus more attention in these areas and provide valuable research and recommendations to stakeholders involved in this space. Stakeholders should take advantage of existing resources and advocate for the creation of new ones.

The following is a non-comprehensive list of publications and resources produced by the DOE and/or national labs in recent years related to the topics of distribution system planning, grid modernization, interconnection, and DERs.

Department of Energy (DOE)

Voice of Experience - Advanced Distribution Management Systems (2015)
Voices of Experience - Integrating Intermittent Resources (2017)
Solar Futures Study (2021)

Lawrence Berkeley National Laboratory (LBNL)

Distribution Systems in a High Distributed Energy Resources Future (2015)
Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning (2016)
Locational Value of Distributed Energy Resources (2021)

National Renewable Energy Laboratory (NREL)

Coordinating Distributed Energy Resources for Grid Services: A Case Study of Pacific Gas & Electric (2018)
New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues (2019)
An Overview of DER Interconnection: Current Practices and Emerging Solutions (2019)
The Evolving U.S. Distribution System: Technologies, Architectures, and Regulations for Realizing a Transactive Marketplace (2020)
Electrification Futures Study (2017-2021)
Storage Futures Study (2021)

Other Resources

Distributed Generation Market Demand (dGen™) Model
Engage Energy Modeling Tool
Multi-Timescale Integrated Dynamic and Scheduling (MIDAS)

Pacific Northwest National Laboratory (PNNL)

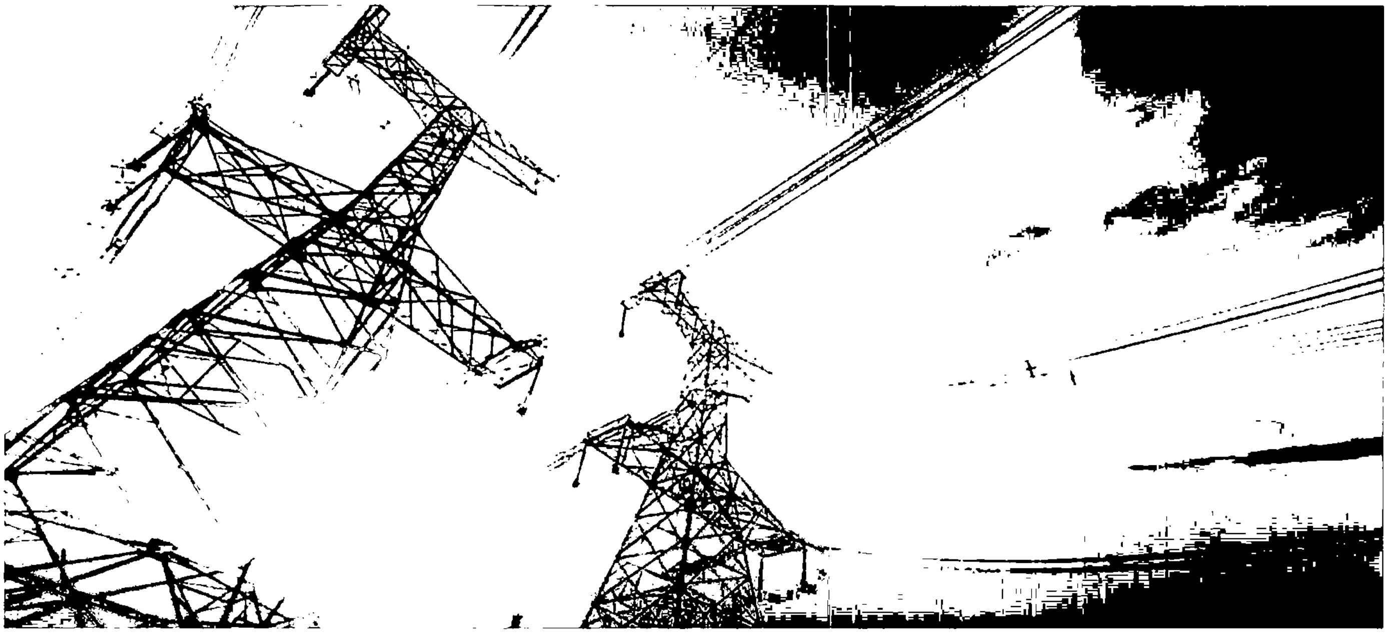
Distribution System Planning - State Examples by Topic (2018)
Modern Distribution Grid Project (2017-Present)

D. Coordinate with National Associations

The National Association of State Energy Officials (NASEO) and National Association of Regulatory Utility Commissioners (NARUC) are well-connected to energy offices and state regulatory bodies across the country and understand the connection between legislation, regulation, and implementation. States should coordinate with these organizations in these areas and advocate for specific support on these topics. NASEO and/or NARUC could develop a comprehensive guide for state legislators to better understand the regulatory and technical outcomes of potential policy decisions. Policymakers and regulators can then work backwards to write effective enabling legislation, regulations, tariffs, etc. to achieve the intended outcomes in a timely, cost-effective, and equitable manner.

3. Realign Utility Incentive Frameworks

When utilities do not have incentives or mandates to conduct distribution system planning with an eye towards decarbonizing, implement grid modernization upgrades, or accomplish interconnection work efficiently, they prioritize other activities which do contribute to their bottom lines. As a result, too often utilities do not assign the number of resources needed to achieve these important policy objectives. States can prioritize all these items by making regulatory reforms that align utility incentives with these goals. In particular, regulatory bodies can adopt performance-based regulation frameworks that specifically measure objectives and either incentivize or penalize utilities based on their progress in meeting specific metrics.



Recommendations

Utilities must be able to plan for grid change drivers other than safety and reliability. Going forward, planning measures specifically to address decarbonization and electrification targets must become an equal part of a utility's service obligation to customers. It is critical to tie decarbonization into updated planning processes so that ratepayers get the most value from upgraded infrastructure as climate goals are being met. This realignment will ensure that utilities can act as a facilitator of DER adoption while also earning a fair rate of return. The following high-level recommendations outline what steps legislatures, policymakers, and regulators can take to effectuate change.

A. Reform Existing Incentive Frameworks and Direct Utilities to Serve as DER Facilitators

Regulators can establish utilities as the facilitator of DER integration, instituting strong mandates, cost recovery authorization, and performance incentives for them to quickly and cost-effectively deploy DERs. For example, establishing specific metrics related to DER integration and tying them to performance incentives that permit a utility to earn a higher return or receive performance payments funded through distribution rates. Adopting performance-based regulation (PBR) mechanisms with clear performance metrics and incentives (and penalties/disincentives where necessary) that are tied to these objectives could be an extremely effective way to align utility interests with those of policymakers, consumers, and industry. Regardless of the specific mechanisms, the metrics established by regulators need to be carefully thought through and must be measurable and achievable. There are generally three core components that should be considered when adopting effective PBR mechanisms:

- Metrics: Record of quantifiable and verifiable metrics (e.g., greenhouse gas emissions, efficiency, customer satisfaction, etc.);
- Scorecards: Allow utility performance to be scored against historical levels and/or peer utilities; and
- Incentives: Tie metrics and scorecards to financial incentives and/or penalties.

PBR mechanisms have been adopted by several jurisdictions, but to date very few utilities have specific metrics that measure their progress in areas such as climate change mitigation, decarbonization, grid modernization, or interconnection. Among those that do, even fewer have specific monetary incentives/disincentives tied to the metrics that have been established/approved by their regulators. Such metrics and performance incentive mechanisms (PIMs) have the potential to be a very effective tool in encouraging utilities to be proactive in addressing policy objectives if designed and implemented correctly. However, great care needs to be given when designing and approving PIMs to ensure that they (1) are tied to the correct metrics and benchmarks; (2) are appropriately sized relative to the customer benefits the utility is creating through its performance; and (3) are not duplicative of work the utility is already required to do or being measured against elsewhere.[10]

Additionally, it is worth noting that performance can be tracked and incentivized through mechanisms that might not be traditionally viewed as a PBR mechanism, but effectively accomplish the same goals. An example might be state level energy efficiency programs, which often contain performance incentives for utilities, but are quite often not part of a larger PBR framework that governs the utility's rate structure more generally.

Case Study: Role of California Utilities in a High DER Future

On June 24, 2021, the CPUC issued an order instituting a rulemaking to modernize the electric grid for a high DER future. This order seeks to address a wide array of issues related to DERs, but importantly, also seeks to address the roles and responsibilities of distribution system operators (DSO). It also posed the following questions on this topic to stakeholders:

1. Should the Commission investigate how to redefine electric distribution IOU roles and responsibilities to accommodate a high DER future grid, appropriately limit market power, and ensure open access for DER providers and aggregators offering retail and wholesale grid services? If so, how?
2. In what ways would a DSO and the various DSO models increase or decrease ratepayer costs and enhance or impede equity?
3. Should the grid architecture discipline be used to establish an overarching grid vision and design that optimizes distribution investments to accommodate high numbers of DERs? If yes, how and over what timeframe?

10 It is worth noting that a PBR structure is not necessarily needed to adopt PIMs. PIMs can and have been successfully deployed as a supplement to more traditional cost of service regulation as well.

4. Should the IOUs be incentivized to cost-effectively prepare for widespread DER deployments? If so, how?
5. What policies could the Commission adopt quickly to enable aggregators to increase the scope of services they provide the distribution grid?"[11]

This rulemaking is still in a relatively early stage, but the CPUC is asking some key foundational questions that get at the root of how the utility incentive framework needs to be restructured to both accommodate a future with a significant amount of DERs, but also to ensure that the utilities are properly incentivized to be a partner and not an obstacle in deploying DERs. On November 15, 2021, the assigned Commissioner issued a scoping ruling that further clarified the next steps of the proceeding and posed additional questions to stakeholders.

Case Study: Hawaii Performance Based Regulation

On February 7, 2019, Hawaii Public Utilities Commission staff issued a proposal to adopt updated performance-based utility regulations designed to encourage Hawaiian Electric Companies (HECO) to cost-effectively achieve Hawaii's energy goals and deliver savings to customers. This proposal attempted to align HECO's business interests with Hawaii's energy needs and customer preferences and included several goals, including ones specific to interconnection, DER asset effectiveness, electrification, and resilience. The ensuing proceeding to adopt the proposal was conducted in two phases, with a Phase 1 Order issued on May 23, 2019, and a Phase 2 Order issued on December 23, 2020, which approved a new PBR framework, continuing the state's transition away from traditional cost-of-service regulation. On May 17, 2021, the HI PUC issued a third order approving the final details of the PBR framework, which took effect on June 1, 2021.

Among the components of the final framework related to DERs and climate mandates are:

1. A quarterly metric tracking the percentage of third-party generation on the electric grid;
2. A quarterly scorecard tracking the number and percent of customers participating in community based renewable energy projects, DER programs, and DR programs, with a target of having 30% of all customers enrolled in one or more programs;
3. A quarterly metric tracking the number of LMI customers participating in community based renewable energy projects, DER programs, and DR programs;
4. Biannual DER asset effectiveness metrics that track the percentages and total MW of DER systems capable, enrolled, and actually providing services in grid services programs, and the total MW and MWh of curtailment from DERs, including partial curtailment or power reductions;
5. A wide variety of electric vehicle related metrics that must be reported annually;
6. Annual greenhouse gas emissions metrics;
7. Annual metrics tracking avoided transmission and distribution investments due directly to the installation or acquisition of non-wires alternatives projects and the total costs of such projects;
8. An annual interconnection experience scorecard that tracks:
    a. the average total number of calendar days to interconnect DER systems <100 kW in size, in a calendar year with the following targets:

11 California Public Utilities Commission, R.21-06-017, Order Instituting a Rulemaking to Modernize the Electric Grid for a High DER Future, June 24, 2021, at 16-17.

    i. 2021 - 115 days;
    ii. 2022 - 100 days;
    iii. 2023 - 85 days;
  b. percentage of independent power producer surveys sent within six months and results provided in full and in summary to the Commission annually with a target of 100 percent;
  c. truck roll-related response times, related to steps within the Companies' control, for meter change-outs for DER and non-DER customers, by individual Company with a target of 10 business days or 14 calendar days; and
9. Annual interconnection experience reported metrics that track:
  a. detailed information on each independent power producer project with a PPA approved by the Commission (e.g., project name, location, technology, size, time to interconnect by step, cost to interconnect, etc.);
  b. the percentage of times the cost of interconnection has exceeded the estimated cost of interconnection for utility scale independent power producer projects.[12]

Some of these metrics are simply designed to track progress and provide informational data to the HI PUC and stakeholders, however, several of them are tied to PIMs. In particular, there is a PIM established for the average number of days it takes to interconnect DER systems, with incentive payments being issued for performance exceeding targets and penalties being assessed for performance that does not meet targets.

While this PBR framework has only just recently been implemented, it represents one of the strongest examples in the country of tying utility revenues to their performance in the areas of DER integration and climate policy and likely has the potential to significantly influence HECO to continually improve its performance in the areas tracked by the metrics, particularly those that are tied to PIMs.

<u>HI PUC Performance Based Regulation Website</u>

<u>Case Study: Illinois Performance Based Regulation</u>

In 2011, the Illinois legislature passed the Energy Infrastructure Modernization Act, which led to the development of performance metrics for investor owned utilities in the areas of advanced metering infrastructure deployment, reliability, credit and collections, voltage optimization, and other areas.

More recently, the Clean Energy and Equitable Jobs Act that went into effect on September 15, 2021, directs changes to existing PBR structures, specifically calling out increasing threats from climate change and the need for the new PBR structure to "enable alignment of utility, customer, community, and environmental goals." To accomplish this, the Act specifically directs the ICC to establish new PBR frameworks that include up to eight metrics and possible PIMs in a variety of areas, including metrics designed around:

1. timeliness of customer requests for interconnection in key milestone areas;
2. offering a variety of affordable rate options;
3. comprehensive and predictable net metering, and maximizing the benefits of grid modernization and clean energy for ratepayers; and
4. improving customer access to utility system information according to consumer demand and

12 Hawaii Public Utilities Commission, Docket No. 2018-0088, Order No. 37787, Appendix A, filed on May 17, 2021 at 5-10.

interest.

Lastly, the Act includes a directive for the ICC to approve reasonable and appropriate tracking metrics related to:

1. minimizing greenhouse gas emissions;
2. enhancing grid flexibility to adapt to increased deployment of non-dispatchable resources;
3. ensuring rates reflect cost savings attributable to grid modernization and utilize DERs that allow the utility to defer or forego traditional investments that would otherwise be required to provide safe and reliable service;
4. creating and sustaining full-time-equivalent jobs and opportunities for all segments of the population and workforce; and
5. maximizing and prioritizing the allocation of grid planning benefits to environmental justice and economically disadvantaged customers and communities.

While these PIMs and metrics have not yet been implemented as of the publication date of this paper, they represent a clear legislative intent to tie a utility's revenues to its performance in meeting clean energy and customer centric objectives. Accordingly, they represent a major opportunity to influence utility behavior and investment in these areas.

Clean Energy and Equitable Jobs Act (Public Act 102-0662) see p. 829-843 of PDF
ICC Webpage on Electric Utility Performance and Tracking Metrics

Case Study: Massachusetts Performance Based Regulation

In late 2018, National Grid filed a rate case with the DPU that included a proposal to recover costs via a PBR mechanism over the next five years. As part of their proposal, National Grid included a variety of metrics, scorecards to track the metrics, and proposed PIMs. In approving the PBR mechanism, the DPU declined to approve National Grid's proposed PIMs as they did not meet several criteria, but the DPU did establish scorecard metrics tracking performance in four general areas:[13] [14]

1. Greenhouse gas emission reductions;
2. Customer engagement; and
3. DER customer experience; and
4. Involuntary terminations.

With respect to the DER customer experience metrics, two notable ones are those that measure the average number of days it takes National Grid to answer DER customer inquiries (measured in number of days) and the percentage of interconnection applications that ultimately receive an authorization to interconnect. The first time that National Grid reported these metrics (for calendar year 2020), the data showed that the average number of days it took to respond to DER customer inquiries increased from a baseline of 7 days in 2018/2019 to 20 days in 2020. The metric measuring applications that receive an authorization to interconnect showed that the percentage of applications reaching interconnection

13 Massachusetts Department of Public Utilities, D.P.U. 18-150, at 76-127.

14 The DPU also recommended that National Grid work with stakeholders in the potential development of both strategic electrification and resiliency metrics, which were developed and are currently under review as part of D.P.U. 21-74.

declined from 73% in 2018/2019 to 63% in 2020.[15]

While National Grid's performance in these areas does not impact their revenue in a positive or negative way, these scorecard metrics are examples of potentially effective tools that a regulator can use to assess the performance of a utility over time. In this case, a continued decline in performance in future years could conceivably lead to the DPU investigating further or taking steps to implement more effective measures to improve performance going forward. If these metrics were not being tracked at all, the DPU may not be aware of these trends or may have only anecdotal evidence of how the utility was performing in these areas.

Case Study: Massachusetts Grid Modernization Tracking Metrics

In 2018, the DPU approved three-year (since amended to four) Grid Modernization Plans filed by each of the three distribution companies in Massachusetts.[16] Following the approval of the plans, the DPU solicited comments on the appropriate form and content of the annual grid modernization report to be submitted by each company. The final annual reporting template established by the DPU provides an extremely detailed overview of the investments made to date with accompanying metrics. Of note are metrics that track the following information on interconnected DERs at the substation and feeder level for each distribution company:

1. Total number by technology or fuel type;
2. Nameplate capacity by technology or fuel type;
3. Estimated annual output by technology or fuel type;
4. Type of customer-owned or operated units by technology and fuel type; and
5. Nameplate capacity as a percentage of peak load.

In addition, the same report tracks the rated capacity and length of each feeder, the number of customers served by the feeder, the amount of kWh delivered to those customers, and the annual peak load of the feeder. It also tracks whether the feeder is automated, partially automated, or not automated, whether VVO capability has been deployed, and if so, key metrics on the performance of the VVO technology. Lastly, it tracks outage duration and frequency on each feeder in the year in question.

This level of detailed information aggregated in one place provides a tremendous resource for the DPU and other stakeholders that can be used for a myriad of purposes beyond just tracking grid modernization investments, such as tracking year over year DER deployments at a granular level, identifying areas of high DER saturation, and identifying areas that may require additional investment. Although none of these metrics are tied to financial incentives or penalties for the utilities, the collection of it in a single location that is accessible to the public provides a level of visibility into each company's distribution system that is extremely comprehensive, allows for very detailed analysis to be performed by interested parties, and should prove valuable in conducting system planning processes.

2018 Reports (type in 20-45 and click "go")
2019 Reports (type in 20-46 and click "go")
2020 Reports (type in 21-30 and click "go")

15 National Grid 2021 PBR Plan Filing, June 15, 2021 (see page 176 of PDF)

16 Massachusetts Department of Public Utilities, D.P.U. 15-120 through 15-122.

Case Study: Minnesota e21 Initiative

In 2014, the e21 Initiative was formed in Minnesota. It was co-convened by the Great Plains Institute and Center for Energy and Environment to "advance a decarbonized, customer-centric, and technologically modern electric system in Minnesota by ensuring that utility business models are aligned with the public interest." This multi-year stakeholder driven effort has produced a significant amount of research and white papers on the topics of performance-based compensation, integrated systems planning, and grid modernization, with the primary goals of:

1. Shifting toward a business model that offers customers more options in how and where their energy is produced and how and where they use it; and
2. Shifting toward a regulatory system that compensates utilities for achieving an agreed-upon set of performance outcomes that the public and customers want.

This effort significantly informed steps taken by the Minnesota Public Utilities Commission (MN PUC) in these areas and on June 12, 2017, they issued an order approving a multi-year rate plan for Xcel Energy and opening docket to "identify and develop performance based metrics and standards, and potentially incentives, to be implemented during a multi-year rate plan.[17]"

On January 9, 2019, following an extensive stakeholder process, the MN PUC issued an order establishing goals and principles governing the development of PIMs for Xcel Energy's rate plan. This immediately resulted in a stakeholder process to develop performance metrics and PIMs, which led to the issuance of a September 18, 2019, order establishing a variety of metrics in the areas of affordability, reliability, customer service quality, environmental performance, and cost-effective alignment of generation and load. Specific metrics were later proposed by Xcel Energy and approved by the MN PUC on April 16, 2020.

Takeaways from Minnesota's work on performance-based regulation include:

1. Incremental progress: Unlike states that have moved to performance-based regulation in response to a crisis or immediate need, Minnesota has been incrementally working on performance-based regulation because many stakeholders believe that it can better align utility performance with public policy goals.
2. Robust stakeholder engagement: Ongoing stakeholder engagement has shaped progress on performance-based regulation in Minnesota, with participation from a broad group of organizations, guidance from third-party facilitation, and support from both internal and external technical experts.
3. A replicable process: Minnesota is following a 7-step replicable process for aligning utility performance with public policy goals by establishing the goals and desired outcomes of utility regulation, metrics, and targets to assess utility performance against those desired outcomes and utilizing performance incentive mechanisms to bring utility performance into alignment with those outcomes where needed. This is a flexible model that other states can use and adapt to meet their own needs.

17 *In the Matter of the Application of Northern States Power for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, Finding of Fact, Conclusions, and Order (June 12, 2017).

e21 Roundtable on Performance Incentive Mechanism

Another resource that summarizes Minnesota's exploration of PBR design and PIMs is SEPA's Renovate Initiative series on Performance Based Regulation, which was released in three parts.

Case Study: New York Realignment of Utility Incentives

On April 25, 2014, the New York Public Service Commission (NY PSC) issued an order instituting a proceeding in regard to reforming the energy vision, which is commonly referred to as the Reforming the Energy Vision, or "REV" Initiative. At a high level, the core objective of REV is to "align electric utility practices and [the] regulatory paradigm with technological advances in information management and power generation and distribution." In opening the proceeding, the NY PSC specifically asked what changes can be made to the existing regulatory framework to better align utility interests with achieving the following energy policy objectives:

1. Enhanced customer knowledge and tools that will support effective management of their total energy bill;
2. Market animation and leverage of ratepayer contributions;
3. System wide efficiency;
4. Fuel and resource diversity;
5. System reliability and resiliency; and
6. Reduction of carbon emissions.[18]

The REV proceeding is a wide-ranging investigation that remains open and that has led to the establishment of many separate related proceedings, but one major focus area was that of the development of market-based platform earnings and outcome-based earning opportunities to better align utility shareholder financial interest with consumer interest.

On July 28, 2015, NY PSC staff issued a white paper on ratemaking and utility business models and on May 19, 2016, the NY PSC issued an order adopting a ratemaking and utility revenue model policy framework, which incorporated many of the staff recommendations as well as comments received in the period between the release of the white paper and issuance of the order. In this order, the NY PSC adopted the concept of complementing traditional cost-based earnings for utilities with platform service revenues (PSRs), which would be earned by utilities through their provision of distributed system platform services. The theory being that PSRs will encourage utilities to support access to their system by DER providers. There is still significant opportunity to expand on this concept as a future revenue stream that drives performance.

One of the tools used to complement the development of PSRs to has been Earnings Adjustment Mechanisms (EAMs), which are intended to be a transitional step in the regulatory process, providing utilities with incremental performance incentives for achieving REV objectives. The principles behind the development of EAMs are articulated in detail in the NY PSC's order adopting the framework, with significant discussion around how EAMs should be structured. Among the opportunity areas identified by the NY PSC for the development of EAMs were:

18 New York Public Service Commission, Case 14-M-0101, Proceeding on Motion of the Commission In Regard to Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014), at 2.

- System efficiency and peak reduction;
- Energy efficiency;
- Interconnection;
- Customer engagement; and
- Greenhouse gas reduction.[19]

EAMs have subsequently been proposed and approved by each of the regulated utilities, including ones based on meeting interconnection goals (which has since been terminated)[20] and others based on DER utilization. While utilities have proposed different strategies for their respective EAMs structures, some of the criteria that have been used for interconnection include whether utilities meet interconnection timelines, independent third-party customer satisfaction surveys, and independent third party audits of failed applications. As far as DER utilization is concerned, one example of how the metric is calculated is National Grid's EAM, which calculates total MWh of DER utilized in a particular year as the sum of the values in the following table:

Technology	Annualized MWh Calculation
Solar Production	MW installed * 13.4% capacity factor * hours/yr
CHP Production	MW installed * 85% capacity factor * hours/yr
Fuel Cell Production	MW installed * 91% capacity factor * hours/yr
Battery Storage Discharge (Production)	[Daily battery inverter discharge rating (MWh)] * [365 days per year]
Battery Storage Charging (Consumption)	[Daily battery inverter discharge rating (MWh)] * [365 days per year] / [83% round trip efficiency]

Incentive payments are then earned by National Grid according to the following schedule:

EAM		Incentive ($)			Target (MWh)		
Metric (Unit)	**Level**	**2018**	**2019**	**2020**	**2018**	**2019**	**2020**
DER Utilization (MWh)	Minimum	$500,000	$500,000	$600,000	191,416	210,929	238,290
	Midpoint	$1,000,000	$1,100,000	$1,200,000	250,104	277,823	322,096
	Maximum	$2,100,000	$2,200,000	$2,300,000	283,302	314,300	365,079

Under this framework, National Grid is financially incentivized to both deploy more DERs and better utilize them on their system each year.

Although even New York officials would likely acknowledge that not all aspects of REV have turned out to be a qualified success and that they still have a long way to go in better aligning the financial

19 https://nyrevconnect.com/rev-briefings/track-two-rev-financial-mechanisms/

20 See New York Public Service Commission, Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Eliminating Interconnection Earning Adjustment Mechanisms (issued April 24, 2019).

earnings mechanisms of electric utilities with new public policy objectives, few states have put as much thought into the future role of an electric distribution company. There are many lessons that can be learned from its leadership in restructuring the regulatory process to date, and the work accomplished through REV so far is a model for other states to follow, particularly in states with restructured markets.

Based on New York's experience, Synapse published a helpful report that provides analysis and recommendations for commissions implementing EAMs.

REV Connect Webpage on Financial Mechanisms (includes links to the EAM proposals put forward by the NY PSC and each utility)

Case Study: Rhode Island Principles for the Development and Review of PIMs

Following a series of orders denying several proposed PIMs in 2017 through 2019, the Rhode Island Public Utilities Commission (RIPUC) undertook an effort to establish principles that would support the development and review of future proposed PIMs. On March 5, 2019, a proposal developed by Commissioner Abigail Anthony in coordination with staff was submitted to the other members of the Commission for their review.

The proposed new principles that were based on existing principles that had previously been established but were "designed to be more concise; less redundant; clearer; more comprehensive; more flexible; and more universally applicable."[21] The five principles proposed were as follows:

> PRINCIPLE 1: A performance incentive mechanism can be considered when the utility lacks an incentive (or has a disincentive) to better align utility performance with the public interest and there is evidence of underperformance or evidence that improved performance will deliver incremental benefits.
>
> PRINCIPLE 2: Incentives should be designed to enable a comparison of the cost of achieving the target to the potential quantifiable and cash benefits.
>
> PRINCIPLE 3: Incentives should be designed to maximize customers' share of total quantifiable, verifiable net benefits. Consideration will be given to the inherent risks and fairness of allocation of both cash and non-cash system, customer, and societal benefits.
>
> PRINCIPLE 4: An incentive should offer the utility no more than necessary to align utility performance with the public interest.
>
> PRINCIPLE 5: The utility should be offered the same incentive for the same benefit. No action should be rewarded more than an alternative action that produces the same benefit.

Following a public comment period on the proposal, the RIPUC adopted the principles as drafted as part of a guidance document that provides direction on how the RIPUC will apply its authority to set rates, tariffs, tolls, and charges with respect to PIMs for public utilities under its jurisdiction.

21 Rhode Island Public Utilities Commission, Docket No. 4943, Guidance Document Regarding Principles to Guide the Development and Review of Performance Incentive Mechanisms, *Principles for Performance Incentive Mechanisms Memorandum*, filed on March 5, 2019, at 2.

This is a useful example of a regulatory body clearly articulating how it plans to exercise its authority to review PIMs that are designed to improve utility performance in areas of public interest, but where the utility currently lacks an incentive to do so. Such guidance is extremely useful for utilities and stakeholders and can inform the manner and form in which PIMs are designed, not to mention expedite the review process for specific PIMs that may be developed.

B. Establish and/or Expand Regulatory Enforcement Measures

While driving utility behavior with respect to DER integration should be primarily accomplished through performance incentives, it is important that utilities also be held accountable for non-performance. For example, timelines for key project development milestones in the interconnection process are often managed at the utilities' discretion with no clear standard that is accepted broadly across the nation. While proposals to implement penalties or other enforcement measures have experienced significant resistance from utilities in states that have attempted to introduce penalties and accountability for missed deadlines, this is an area in need of urgent intervention on the part of regulators and should be explored.

Delayed or incomplete interconnection studies can compound long construction timelines that often do not align with the rapid deployment capability of DER including the payment for upgrades made to utilities. It is critical that regulators are entrusted with the requisite authority to establish performance standards (such as interconnection timelines) with enforceable deadlines and penalties and that regulators utilize that authority to establish such standards, timelines, and penalty structures on both a macro scale as well as at the individual project level.

Case Study: Massachusetts Interconnection Timeline Enforcement Mechanism

In 2012, the Massachusetts state legislature passed An Act Relative to Competitively Priced Electricity in the Commonwealth, which was subsequently signed into law by the Governor. Among the many provisions in the act was one the directed the DPU to develop a timeline enforcement mechanism:

> SECTION 49. The department of public utilities shall develop an enforceable standard interconnection timeline for the interconnection of distributed generation facilities. Timelines may vary depending on the size and type of the facility or other factors as determined by the department. The department shall implement such timeline not later than November 1, 2013. The department shall enforce established timelines as part of its service quality standards review under section 1I of chapter 164 or by whatever enforcement mechanism is determined appropriate by the department.[22]

Following input from stakeholders, the DPU issued an order and accompanying guidance adopting a joint proposal for a Timeline Enforcement Mechanism framework. This mechanism created a process by which the electric distribution companies were required to track the number of days it took them to complete the review of different types of interconnection applications.[23] Performance is weighted

22 *An Act Relative to Competitively Priced Electricity in the Commonwealth*, St. 2012, c. 209, § 49.

23 These timelines were established in D.P.U. 11-75-E pursuant to recommendations from a report prepared by the Massachusetts Distributed Generation Working Group.

according to the average number of days it took the utilities to process each type of application.[24] If a utility uses more time on average than they are permitted to under the metric, they are assessed a penalty. If a utility uses less time on average than they are permitted under the metric, they are eligible to earn a financial offset, which can be applied against any penalties incurred in the following year. Both penalties and offsets are calculated on a linear sliding scale. The framework adopted by the DPU also establishes a maximum amount for both penalties and offsets.

This system remains in effect today, although in the last 2-3 years there have been some discussions about modifications to make it more effective.[25] In particular, one challenge has been that the utilities are able to exclude many of the more complex applications from counting against their performance in meeting the metrics established by the mechanism. Additionally, the utilities can place certain types of applications "on hold," which essentially means that they stop counting the passage of days applied against them in the metric until the hold is removed. Good performance on processing the applications of smaller systems in a timely manner coupled with these exceptions for larger systems has led to the utilities generally earning the maximum or very close to the maximum offset allowable each year.[26] However, while the mechanism may be imperfect, it has served as a model to consider for other states, including Maine where interconnection timeline-related penalties are currently under discussion.

Case Study: Maine Interconnection Timeline Requirements and Penalties

In 2019, An Act To Promote Solar Energy Projects and Distributed Generation Resources in Maine was enacted to implement a new distributed generation procurement program and expanded net metering program. This legislation also directed the Maine Public Utilities Commission to establish interconnection timeline requirements and financial penalties[27] to ensure the success of the distribution generation procurement program. While the frameworks of specific penalties were discussed in the later interconnection rulemaking,[28] ultimately the ME PUC issued an order that revised the interconnection tariff[29] to include a new section that identifies the ability for the ME PUC to assess financial penalties consistent with the maximum administrative penalties allowed[30] for failure to comply with timelines contained in Chapter 324, Small Generator Interconnection Procedures, and in an interconnection agreement. The ME PUC noted that "more work is required to develop whether and when penalties should be assessed and the methodology for assessment" and noted that it will address more specific penalty provisions in a future order.

Case Study: Minnesota Quality Service Plan Customer Complaint Metrics

24 Application types are classified into three general groups, simplified, expedited, and standard, with each group being increasingly more complex and having longer allowed timelines for completion.

25 The DPU has accepted comments on possible revisions to the Timeline Enforcement Mechanism as part of its DPU 19-55 investigation into interconnection, but is awaiting more data from the distribution companies before taking any further steps. This data is scheduled to be provided in February 2022.

26 A notable exception is that Eversource may be assessed a penalty for its performance in 2020, but the DPU has not yet ruled on the matter (see DPU 20-42) as of the date of this publication.

27 More specifically, 35-A M.R.S. § 3482(4) states that: "the commission shall establish by rule requirements for investor-owned transmission and distribution utilities to interconnect distributed generation resources to the grid and financial penalties to ensure timely actions by those utilities to achieve the procurements under sections 3485 and 3486."

28 See Maine Public Utilities Commission, Docket No. 2020-00004.

29 Maine Public Utilities Commission, Docket No. 2020-00004, *Order Amending Rule and Statement of Factual and Policy Basis*, issued March 6, 2020.

30 See Title 35-A, Part 1, Chapter 15.

In December 2019, 129 complaints regarding delays and technical issues with Xcel Energy's solar interconnection process were filed with the MN PUC by solar installers. Pursuant to Xcel Energy's Quality of Service Plan (QSP) tariff approved by the MN PUC in 2013, there is a $1 million underperformance penalty that may be assessed for each benchmark that is not met, inclusive of customer complaint metrics.[31]

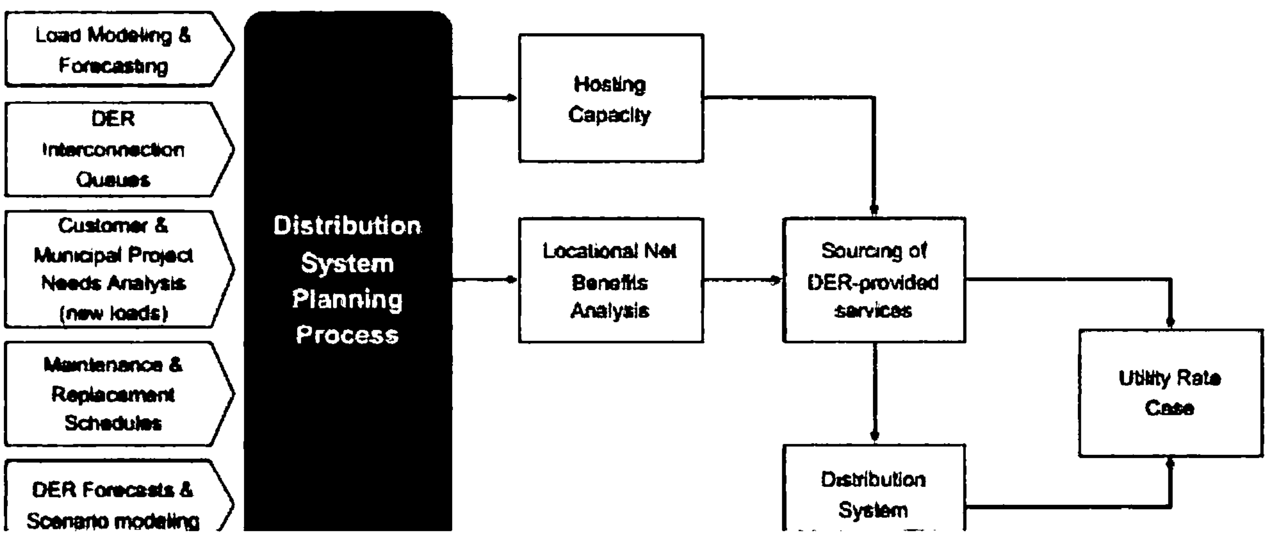
In May 2020, Xcel Energy filed its annual QSP report for 2019 and requested that the MN PUC exclude the 129 complaints from solar installers, arguing that they did not meet the definition of "customer complaint" filed by a "customer" under the QSP tariff. Following several months during which comments and oral arguments were made by interested parties, on January 21, 2021, the MN PUC voted to deny Xcel Energy's request to dismiss the 129 complaints, assess them a $1 million penalty, and directed them to implement reforms and ongoing reporting requirements related to interconnection to avoid such issues in the future. This was later memorialized in a written order issued by the MN PUC on February 18, 2021. Both the QSP metrics/penalties and the reforms and reporting requirements directed by the MN PUC in response to the customer complaints received are good examples of how metrics and penalties can be applied to drive utility performance related to interconnection of DERs.

IREC Blog Post Summarizing MN PUC Action

4. Establish Integrated Distribution and Transmission System Planning Processes

Utilities have decades of experience in planning the development of an electric grid system that relies on centralized sources of generation but planning for a high-DER future in which the building and transportation sectors are increasingly electrified will require a very different approach -- one which in some instances is diametrically opposed to long-standing traditions within the industry. While some utilities have embraced new forms of planning, others will require mandates to move beyond traditional methods to meet decarbonization goals and changing customer demands across the country.

Figure 2: The modern distribution system planning process



Source: DISTRIBUTION SYSTEM PLANNING Proactively Planning for More Distributed Assets at the Grid Edge (AEE)

31 Penalties assessed under the QSP tariff are divided between refunds to customer bills (50%) and maintenance and repair of a utility's distribution system (50%). They are not eligible for cost recovery in future rate proceedings.

Recommendations

To integrate distributed generation, technologies such as advanced inverters and batteries, electric vehicles, the electrification of buildings, and other DERs as quickly and efficiently as possible, a long-term plan of how best to incorporate these new features into the electric grid (both distribution and transmission) is vital. Such planning should be conducted by utilities in coordination with long-term planning committees at state agencies and RTOs. State regulators or some other governing body should also convene workshops to identify key issues and think through and implement a better process for coordination.

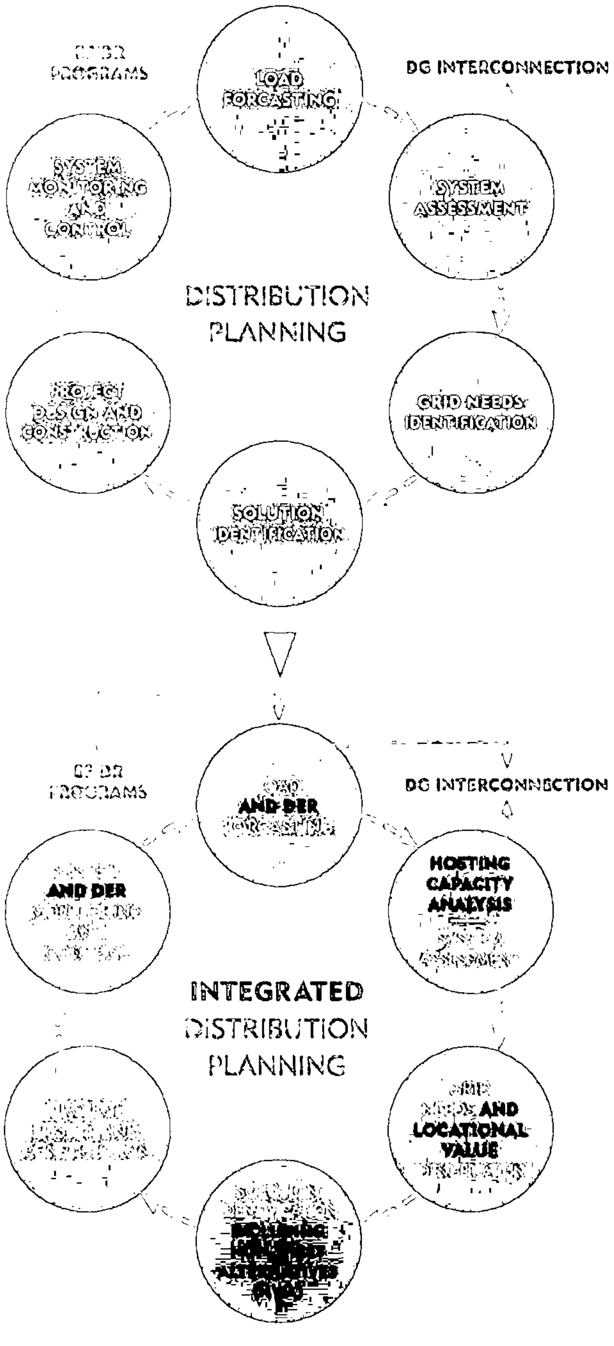


FIGURE 2. Transitioning to Integrated Distribution Planning

Source: Integrated Distribution Planning: A Path Forward, GridLab

A. Implement Integrated Distribution System Planning Processes

At minimum, state policymakers should implement Integrated Distributed Planning (IDP) mandates for the utilities that they regulate. This step is essential to advancing decarbonization and grid modernization goals for reliable, affordable electricity service in an increasingly complex energy ecosystem.

Though it centers on distribution, IDP applies a holistic planning approach that identifies near- and long-term solutions to issues both at the customer-level and at the nexus of the distribution and transmission systems. As a result, it incorporates traditional resource planning needs such as safety, reliability, and affordability, but also incorporates growth in clean energy technologies (DG, batteries, EVs, efficiency, etc.) and increased customer options.

Overall, IDP promotes cost-effective outcomes that assign costs and provide benefits appropriately to ensure a resilient and technically sound grid. The IDP framework grew from Hawaii's proactive distribution planning approach, which was developed to meet the state's substantial shift in 2015 to a 100% RPS target by 2045. As of November 2020, nine states and the District of Columbia were implementing or had already established proactive distribution planning practices, with another seventeen states and Puerto Rico actively investigating the implementation of IDP in some manner (28 entities in total).

Investigating and mandating IDP processes will facilitate the critical planning needed to enable access to sustained reliable energy generation and service. A phased approach to integrated planning is also crucial as states and jurisdictions will be starting from varied points on the spectrum. A first step is identifying where the capabilities of different utilities are today and creating a roadmap for how they can adopt more advanced IDP processes in the future. Other key considerations are implementing new technological solutions to provide utilities and other parties with more information useful to the planning process, investing in and building the ability to collect and synthesize large amounts of data, breaking down silos between different groups within utility companies to encourage collaboration, and examining whether existing regulatory frameworks need to be altered in order for IDP processes to be implemented and evolve over time.

Research Papers and Planning Roadmaps

SEPA's Integrated Distribution Planning: A Framework for the Future report delves deep into what is necessary to transition from a traditional planning to an integrated planning approach. The report outlines the steps necessary to complete a phased transition including challenges and ways to overcome them.

NARUC and NASEO have also partnered through their Cohort Roadmap project to provide comprehensive planning roadmaps for states, broken down by the type of electricity market structure they have.

The DOE national labs have also jointly developed research materials in recent years on this topic, which summarize the actions different states have taken in this area:

State Engagement in Electric Distribution System Planning (2017)
Distribution System Planning - State Examples by Topic (2018)

Lastly, Acadia Center recently released its RESPECT report, which calls for sweeping reforms to system planning processes, recommending that electric and gas distribution utility planning occur concurrently and be managed by non-utility entities. In particular, the report highlights that utilities are extremely unlikely to plan against their financial interests, even if substantial reforms are made to the incentive structure that drives their investments.

Case Study: California Distribution Resource Planning

California has long been a leader in incorporating distributed resources into utility planning, having as far back as 2001 included language in Public Utilities Code Section 353.5 that required "[e]ach electrical corporation, as part of its distribution planning process, shall consider nonutility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost." In October 2013, AB 327 was signed into law by California Governor Jerry Brown, which greatly expanded upon these existing requirements. Among other things, the law instituted Public Utilities Code Section 769, which required all electrical corporations (i.e. investor owned utilities and small and multi-jurisdictional utilities) to file Distribution Resources Plan Proposals (DRPs) with the CPUC by July 1, 2015. The DRPs filed were required to:

(1) evaluate locational benefits and costs of DERs located on the distribution system;
(2) propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives;

(3) propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources;
(4) identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers; and
(5) identify barriers to the deployment of distributed resources.[32]

On August 13, 2014, the CPUC issued an order instituting a rulemaking (R. 14-08-013) to implement the law (DRP Proceeding). On November 17, 2014, the Commissioner assigned to the DRP Proceeding issued a ruling that provided further guidance for the DRPs that were to be submitted and articulated the following goals in addition to the requirements specified by the law:[33]

(1) to modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs' networks;
(2) to enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and
(3) to animate opportunities for DERs to realize benefits through the provision of grid services.

On October 2, 2014, the CPUC issued a second order instituting a rulemaking (R.14-10-003) to consider the development and adoption of a regulatory framework to provide policy consistency for the direction and review of demand-side resource programs (IDER Proceeding). While the DRP Proceeding focused on distribution planning, the IDER Proceeding focused on DER sourcing mechanisms and adopted a Competitive Solicitation Framework is used by the DRP's Distribution Investment Deferral Framework (DIDF) to procure DERs to defer traditional investments planned by the utilities to address grid needs.

On May 3, 2017, the CPUC issued a DER action plan entitled California's Distributed Energy Resources Action Plan: Aligning Vision and Action, which established elements that were incorporated into the DRP and IDER Proceedings. According to the CPUC, since 2014, the DRP and IDER Proceedings have:

- Made aspects of the electric utilities' distribution planning processes transparent through public filings required by the DIDF;
- Aligned electric utility distribution planning process timeframes with the DIDF;
- Implemented a Request for Offers solicitation process to procure DERs that can defer grid investments;
- Made significant progress on an alternate DER procurement process using tariffs;
- Developed integration capacity analysis and locational net-benefit analysis tools with sufficient data provided on the DRP Data Portals to facilitate third-party DER siting and planning;
- Addressed confidentiality concerns such that the utility distribution planning filings could be made public with minimal exceptions and DER siting tools could be hosted on public DRP Data Portals;
- Adopted an integration capacity analysis methodology that is in use for streamlining Rule 21 interconnection; and

32 California Public Utilities Code, Section 769(b)

33 This was later supplemented by a final February 6, 2015 ruling.

- Ensured utility General Rate Case filings address the technologies and grid upgrades necessary to integrate DERs in accordance with a Grid Modernization Framework.[34]

These are significant accomplishments, but as the CPUC notes in its June 24, 2021, Order Instituting a Rulemaking to Modernize the Electric Grid for a High DER Future, there are additional elements of the integrated system planning processes that have not been fully resolved by these two proceedings and that may be included in this new rulemaking, which is now underway.

- Integration capacity analysis and locational net-benefit analysis tools and DRP data portal development;
- DER growth forecasting;
- Distribution grid planning, especially with respect to DER hosting capacity;
- DIDF and DER sourcing mechanisms for the deferral of traditional infrastructure (e.g., requests for offers and tariffs);
- Ongoing innovation and demonstration activities;
- Grid modernization framework to accommodate increasing numbers of DERs;
- Advanced smart inverter functionality for dispatch to provide grid services;
- Utilities incorporating into distribution planning the consideration of DER solutions as well as traditional solutions;
- Utility incentives to support DER integration; and
- Utility and affiliate ownership of DERs.[35]

California has made tremendous progress with IDP and incorporating DERs and is a model for other states to follow, but as can be clearly seen, there is still much more work to be done despite these efforts having been underway for over eight years. This further underscores the need for regulators and utilities that have not yet begun to think through these challenges to commence doing so as soon as possible.

Case Study: Hawaii Integrated Grid Planning

Beginning in 2014, the Hawaii Public Utilities Commission (HI PUC) started to investigate the existing Integrated Resource Plans (IRP) and Power Supply Improvement Plans (PSIPs) that had been used to conduct system planning up until that point. As part of their investigations, they recognized that existing planning processes needed to be changed to better align the Hawaii Electric Companies' (HECO Companies) with "customer interests and the State's public policy goals."[36]

Following an extensive multi-year proceeding in which multiple rounds of PSIPs were submitted and commented upon by stakeholders, on July 14, 2017, the HI PUC issued an order providing guidance regarding the implementation and future planning activities of the HECO Companies. Among other things, the order found significant improvements in the PSIPs that had most recently been submitted and noted that the near-term action plans and long-range analysis in the PSIPs "provide useful context for evaluating pending and future operational decisions and resource acquisition

34 California Public Utilities Commission, *OIR to to Modernize the Electric Grid for a High Distributed Energy Resources Future*, June 24, 2014, R.21-06-017, at 5-6.

35 California Public Utilities Commission, *OIR to to Modernize the Electric Grid for a High Distributed Energy Resources Future*, June 24, 2014, R.21-06-017, at 7.

36 Hawaii Public Utilities Commission, Docket No. 2012-0036, Order No. 32052, filed on April 28, 2014, at 79.

alternatives."[37]

Approximately one month after the issuance of this order, the HECO Companies filed a detailed Grid Modernization Strategy Report on August 29, 2017, which detailed their proposed strategy for meeting the objectives outlined by the HI PUC in the prior proceeding to review the PSIPs. This was later supplemented by an Integrated Grid Planning (IGP) Report that was submitted on March 1, 2018, which outlined a new planning process that would (1) incorporate comprehensive, customer centric, planning and sourcing process, (2) identify and enable the optimal mix of DER, DR, and grid-scale resources, and (3) harmonize resource, transmission, and distribution planning processes.

In the IGP report, the HECO Companies proposed to merge three separate planning processes - generation, transmission, and distribution - while simultaneously integrating solution procurement into the process. The report also included the goals of "identifying gross system needs, coordinating solutions, and developing an optimized, cost-effective portfolio of assets."[38] The HECO Companies noted that integrating all of these processes should allow the new distributed and grid-scale resources that would be built under the plans to provide power generation and ancillary services, resulting in significant savings for customers.

The HECO Companies further explained that they proposed to complete the majority of the IGP process in the following four steps over 18 months:

1. Form a working group to assist in the development of the following forecasts and input assumptions:
    a. Planning Requirements (e.g., reliability, hosting capacity, etc.)
    b. Input Assumptions (market driven metrics such as fuel costs)
    c. Fixed Assumptions (metrics under control of the HECO Companies, such as PPA renewals)
    d. Customer Needs and Policy Goals
2. Identify resource, transmission, and distribution needs using advanced modeling software to identify an optimal portfolio of solutions.
3. Identify how needs identified in step two will be met through procurements, pricing, and programs.
4. Evaluate and optimize the solutions identified in step three.

Following the conclusion of this process, the HECO Companies proposed to submit a five-year plan with discrete investments, programs, and pricing proposals to the HI PUC for review. Lastly, the HECO Companies proposed an extensive stakeholder engagement process, with an approximately 20-member Stakeholder Council providing feedback throughout the process, a technical advisory panel to assess tools and methods, and working groups made up of subject matter experts to assist in specific aspects of the planning process.

On July 12, 2018, the HI PUC issued an order to investigate the IGP report filed by the HECO Companies and to take steps towards adopting a version of the IGP process it outlined. As part of the proceeding opened by this order, the HECO Companies submitted an IGP work plan on December 14, 2018, which was later accepted by the HI PUC in a March 14, 2019, order. Since the issuance of this

37 Hawaii Public Utilities Commission, Docket No. 2014-0183, Order No. 34696, filed on July 14, 2017, at 2, 4.

38 IGP Report at 14

order, the HECO Companies have been conducting the IGP planning process as outlined in its report, work plan, and accepted by the HI PUC. The docket opened in July 2018 remains open, however, with the IGP planning process well underway and adjustments and guidance from the HI PUC being made along the way.

Hawaii's IGP planning process represents one of the most advanced IDP processes currently in place in the United States and is an excellent model for other states, particularly non-restructured states whose utilities remain vertically integrated. It also illustrates the tremendous amount of time and effort that goes into developing such a process and highlights that whatever is put in place needs to be highly adaptable and involve significantly more stakeholders than have previously been included in such processes in the past.

HECO Companies IGP Website
Stakeholder Technical Working Group Webpage
Technical Advisory Panel Webpage

Case Study: Illinois Division of Integrated Distribution Planning

While the implementation process has yet to fully commence, the recently enacted Clean Energy and Equitable Jobs Act specifically directs the establishment of Multi-Year Integrated Grid Plans and directs the ICC to establish a Division of Integrated Distribution Planning, which must have a staff of at least 13 individuals and will be responsible for reviewing and evaluating the Integrated Grid Plans developed by electric utilities serving more than 500,000 retail customers. The Act sets forth an extremely detailed framework under which the Integrated Grid Plans must be developed and evaluated, including detailed goals for what the plans should be designed to accomplish, which will help guide the ICC's review of the plans.

Clean Energy and Equitable Jobs Act (Public Act 102-0662) see p. 706-734 of PDF

Case Study: New York Integrated Distribution System Planning

As described above in the New York case study regarding realigning utility incentives, the REV Initiative is a wide ranging investigation that remains open and which has resulted in many separate related proceedings, with another major focus area being the development of Distributed System Implementation Plans (DSIPs).

On February 26, 2015, the NY PSC issued an order that adopted a regulatory policy framework and implementation plan. Included in this plan was a staff proposal to reframe the role of the utility as a distributed system platform provider, one of the three core functions of which would be to implement integrated system planning processes in the form of a DSIP. As the NY PSC outlined, DSIPs were to be multi-year plans that included supply/demand planning, transmission and distribution upgrades, and transmission and distribution maintenance. They would also contain proposals for capital and operating expenditures and system information needed by third parties to participate in markets.
In addition to developing DSIPs, the other core functions of a distribution system platform provider identified by the NY PSC were grid operations (specifically, integrating DERs), and market operations, structure, and products (also with an emphasis on integrating attributes of DERs into these areas).

In its order establishing these concepts, the NY PSC also directed staff to develop guidance regarding the contents of DSIPs and the utilities to develop initial DSIPs based on this guidance. The staff proposal was issued on October 15, 2015, and was approved by the NY PSC in an order issued on April 20, 2016. This was subsequently followed by DSIPs submitted by each utility on June 30, 2016, a joint supplemental DSIP submitted by utilities on November 1, 2016, and by a March 9, 2017, order directing the utilities to take specific actions with respect to the DSIPs they filed.

Integrating DERs was a major focus of the NY PSC's order approving staff's proposed guidance, with the NY PSC requiring DSIPs to do the following (among other things):

- include system planning data and information that will allow DER providers to make economic decisions regarding best locations for future DER investments;
- include an initial assessment of the capability of the distribution system to accommodate and host DERs;
- identify specific locations within the distribution system that are the highest priority for distribution capacity and operational relief;
- provide granular substation and feeder level data;
- discuss the impact that significantly increased DER penetration will have on system demand forecasts;
- identify the specific expected contribution to peak load, energy reduction, and load shaping for each DER resource for the next five years;
- describe the details of other procedures and/or programs which it may implement to increase the quantity and value of DER resources;
- develop a standard communication process between the utilities and DER providers to identify opportunities for DER deployment, and coordinate regarding the DER providers' upcoming projects and any impacts such projects might have on the utility grid;
- include a description of the current capital budgeting process and an explanation of how the process integrates and considers DER installed on the utility's distribution system;
- provide details on upgrades required to support DSP capabilities and projects where DER has the potential to impact project needs;
- include identification of specific areas in each utility's footprint where there is an impending infrastructure upgrade need and where DERs would potentially provide infrastructure avoidance value or other reliability or operational benefits;
- explain how the utility expects to maximize the integration of DERs in such beneficial areas to avoid making unnecessary investments;
- actively collaborate with DER providers and other stakeholders in developing its plan;
- propose individual demonstration projects that provide the opportunity to use alternate approaches to increasing hosting capacity and facilitate greater DER penetration;
- establish plans to improve automation, monitoring, and communications infrastructure to better integrate DERs into the grid and markets;
- develop a process for interconnecting DERs through an online portal.[39]

While significant progress has been made in New York on the establishment of IDP processes, the development of DSIPs remains an iterative process and the proceedings related to their establishment remain open. Additionally, certain aspects of the process are not ideal, such as the limited ability to

39 New York Public Service Commission, Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016), at 23-54.

provide stakeholder feedback on the plans and the relative lack of oversight the NY PSC exercises in reviewing the plans (e.g., the plans are not subject to a formal regulatory approval process, however the investments are identified in utility rate cases). Nonetheless, the vision articulated by regulators in New York is one of the most forward-thinking approaches in the United States, has resulted in major improvements to date, and likely represents one of the most comprehensive efforts at reforming distribution system planning processes in a restructured electricity market.

Case 14-M-0101 (Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision)

Case 16-M-0411 (In the Matter of Distributed System Implementation Plans)

B. Create Intrastate and Regional Forums to Encourage Cooperation

One useful tool to assist states and other jurisdictions in developing and executing effective planning processes is to establish a forum in which affected stakeholders can discuss the components of what a successful process might look like. For example, convening a group of representatives from utilities, relevant state agencies, ratepayer advocates, the DER, EV, and energy efficiency sectors, and environmental groups to discuss this topic and/or review utility plans before they are filed with regulators can lead to more successful outcomes. This allows for a diversity of viewpoints and opinions to be heard and discussed before a plan is filed as part of what could be a more contentious and one-sided proceeding before a utility commission. Establishing a working group, committee, or council tasked with developing a planning process via legislation and/or direction from a state regulatory agency is one way to ensure that all stakeholder voices are heard and that more effective processes are put in place.

Also, most jurisdictions in the United States are part of a larger regional grid. As such, they may very well be impacted by planning decisions made by neighboring jurisdictions. Additionally, transmission planning and distribution planning are not always performed in conjunction with one another. This creates a need for greater communication and coordination between states, distribution companies, transmission operators, and RTOs. As more states adopt new ways of conducting distribution planning and DERs play a larger role in wholesale markets, it is critical that regional stakeholder forums be established so that there is visibility into what is occurring at both the transmission and distribution levels of the electric grid.

While there are few examples of groups that have been formally established to specifically review system planning efforts at the state level, the best example of an intrastate forum on this topic likely comes from Hawaii, which has established a Stakeholder Council providing feedback throughout the IGP process the utilities are conducting (see system planning case study above), as well as a technical advisory panel to assess tools and methods being utilized in the process.[40] The Stakeholder Council is comprised of the following representatives:

Stakeholder Technical Working Group Webpage
Technical Advisory Panel Webpage

5. Reform Cost Allocation Methodologies

40 Similar groups exist for different purposes in other jurisdictions that could also serve as models. For example, the Massachusetts Energy Efficiency Advisory Council or the New York State Climate Action Council.

In setting rates for utility service and otherwise providing for the recovery of costs by utilities, state regulatory bodies have historically applied the principle of cost causation; that is, the entity responsible for the cost to be incurred is responsible for payment of the costs (i.e., cost responsibility follows cost incurrence). This principle certainly has merit when there is truly a sole beneficiary of such upgrade costs. However, as applied in the context of interconnecting DERs, it will severely limit the ability of states to reach their clean energy goals as more DERs are added to the distribution system and is inappropriate to apply to many of the types of system upgrades required to interconnect DERs.

To date, the cost causation principle has been able to be borne by the DER industry in limited circumstances where DERs were able to find and pick the low hanging fruit of available capacity on circuits and substations as well as instances in which the costs of upgrading utility infrastructure were not exorbitant. The ability to bear such costs in the early stages of a DER market's development, though, in no way proves the validity of applying cost causation principle to all upgrades required to interconnect DERs. States that are leaders in deploying DERs have in recent years begun to experience challenges interconnecting new resources as generation capacity on distribution feeders and substations begins to meet or exceed hosting capacity limits. This has led to situations where interconnection upgrade costs assessed to individual DERs have become prohibitively expensive because the types of upgrades they must pay for to interconnect are massive investments in the bulk power system. Because such upgrades often result in significant benefits to customers other than the DERs themselves in the form of improved reliability, power quality, resilience, efficiency, and increased decarbonization, passing the costs solely onto DERs by applying the cost causation principle presents issues of "free ridership" for other beneficiaries.

Additionally, utility infrastructure can be "lumpy" in nature - meaning that based on standard equipment sizing, additional capacity is created well beyond the needs of one interconnecting customer. Under current cost causation rules, a triggering project would have to pay 100% of the cost even though that interconnecting customer may not receive 100% of the benefit. While it is certainly not in the public interest to eliminate all price signals to DERs regarding interconnection, assessing individual or small groups of DERs costs associated with funding bulk power system upgrades, such as the installation of a new transformer at a substation or the reconductoring of a transmission line, results in situations where no new DERs will be constructed in certain parts of the distribution system until the utility makes these upgrades through its normal course of business (e.g. replacing aging equipment, adding capacity to account for load growth, etc.).

In some jurisdictions, studying facilities with common points of interconnection together and implementing cost sharing measures amongst them has been explored as an early step, but such measures present other challenges and are no guarantee that DERs will continue to be deployed as more significant upgrades are triggered. This is because once a part of the distribution system reaches a certain level of DER penetration, interconnection upgrades are still too expensive and are inappropriate to share solely amongst groups of customers interconnecting at the same location. Because of this, some states are beginning to recognize the need for advanced cost sharing methodologies that equitably share the costs of upgrading the electric power system across all customers who benefit from them, including ratepayers at large.[41]

There are several steps that states can take to effectively move away from existing cost allocation frameworks. The first step is to adopt a cost sharing policy that distributes the necessary costs across a

41 It is worth noting that to the extent a state provides incentives or other financial support to DERs, these ratepayer funded subsidies would presumably need to be set at levels high enough to cover the costs of interconnection related upgrades anyways. As a result, another argument in favor of recovering system upgrade costs from the actual beneficiaries of those upgrades is that they may have had to otherwise indirectly pay for them to be constructed via other ratepayer funded programs to support the deployment of the DERs.

wider range of beneficiaries, properly recognizing that when constructing bulk power system upgrades of a certain magnitude, benefits from constructing those upgrades flow to customers other than to just the DERs seeking to interconnect. This is consistent with general ratemaking principles regarding the setting of delivery rates, through which in instances of public policy or where other discernible beneficiaries can be identified, costs are routinely assigned and recovered from customers other than just a single entity deemed responsible for the cost. The second moves beyond cost sharing by creating a market-based grid access fee to guide project developers to the best interconnection sites through dynamic pricing.

Recommendations

Regulatory bodies should direct utilities to move away from a strict adherence to the cost causation principle model as part of a comprehensive grid planning process. States can do this in steps, starting with a multi-beneficiary cost sharing approach and then moving to a new paradigm where cost sharing is spread among all grid beneficiaries through a market-based fee structure. Implementation of these new approaches should ideally be done in conjunction with reforms to distribution system planning procedures and the implementation of grid modernization measures.

A. Implement Multi-Beneficiary Cost Sharing

In coordination with updated distribution system planning directives, regulatory bodies should direct utilities to put forward a framework for multi-beneficiary cost sharing and convene a public stakeholder process to provide insight on the framework. This framework should be assessed on a utility's ability to determine the costs of making system upgrades to support DER growth and electrification of the transportation and building sectors. The framework should include a process for establishing a "per kW" cost for interconnecting DERs for the upgrades associated with the feeder or other subunit of the distribution network to which their facility is interconnecting. The shared cost would be assessed to each DG facility interconnecting to that portion of the network based upon applied capacity until further system upgrades are required. The portions of the network targeted for upgrades may be identified either by a utility's analysis of future expansion needs or by "the market" (i.e., pending requests for interconnection).[42] The framework should include a rationale and approach for apportioning system-level upgrade costs to both interconnecting DERs and customers at large to the extent that the upgrade(s) contributes to the state's decarbonization goals and utility system planning objectives.

There are relatively few examples of states directly re-examining the cost causation principle to date, with the only states to seriously consider making substantive changes thus far being Maryland, Massachusetts, New Mexico, and New York, with much of the implementation details in each jurisdiction yet to take place.[43] That said, many other states are reaching similar levels of DER deployment and are likely to be faced with the same challenges soon. The one other place where the cost causation principle is being re-examined at this time is at the federal level, where the Federal Energy Regulatory Commission (FERC) is currently investigating whether changes should be made to the cost allocation methodology used to assess upgrade costs to generators interconnecting to the

42 For example, such upgrades could be proactively identified by utilities through a reformed distribution system planning process that incorporates planning for decarbonization, electrification, and DER growth.

43 To the extent that a state has developed more advanced IDP procedures (e.g. California and Hawaii), however, it is possible that the long-term system plans that are being implemented would result in planned system upgrades that are designed to support the integration of DERs. It is also possible that such upgrades are being funded through distribution rates. In the long-term, the ideal scenario is that cost sharing of this nature is implemented via long-term system planning. It is worth noting that the second phase of the Massachusetts DPU proceeding described here intends to examine how reforms to cost allocation methodologies can be integrated into a comprehensive distribution system planning process.

transmission system.

Case Study: Massachusetts Multi-beneficiary Cost Allocation

As part of ongoing discussions in Massachusetts related to broader interconnection challenges, multiple stakeholders expressed a strong interest in revisiting the cost causation principle of assigning all interconnection upgrade costs to the interconnecting party. To further explore the idea of cost sharing for interconnection upgrades, the DPU opened DPU-20-75 in October 2020, the purpose of which is twofold: (1) to consider the establishment of a comprehensive distribution system planning process that incorporates DER growth and load growth from electrification of the building and transportation sectors, and (2) to consider how the costs of system upgrades triggered by interconnecting resources is allocated.

In conjunction with the issuance of the order opening the DPU-20-75 investigation, the DPU issued an accompanying straw proposal, which focuses on improving the efficiency of the interconnection process by allowing the utilities to make proactive investments in system modifications (Capital Investment Projects or CIPs) that are designed to facilitate timely and more cost effective interconnection of DG facilities, particularly in areas that are at or near hosting capacity limits. In its straw proposal, the DPU proposes that, as part of the pre-approval process for authorizing individual CIPs, the utility would identify the cost of and kW capacity enabled by the proposed CIP, and the DPU would then establish a $/kW CIP fee for the utility to allocate to each interconnecting facility that subsequently benefits from the CIP. Under the DPU's proposal, should all the hosting capacity that is enabled by a CIP be interconnected within the CIP's amortization period, the total net cost to ratepayers ends up being zero as the fees paid by interconnecting facilities fully offset the upfront costs.

As proposed by the DPU, CIPs could include, but are not limited to: (1) substation transformer replacements; (2) reconductoring of distribution feeders; (3) distribution protection measures; and (4) transmission related upgrades triggered by resources interconnecting to the distribution system. The reconciling charge would be structured as a non-bypassable volumetric charge differentiated by rate class and would be included as part of a customer's distribution charge. A utility would only be permitted to recover costs via the reconciling mechanism once it has demonstrated the pre-approved investment had been made, and cost recovery would be subject to an annual rate cap.

The DPU has stated that it believes the CIP fee structure coupled with the existing cost allocation structures (i.e., the cost causation principle and the sharing of upgrade costs through group study provisions), are sufficient to address assignment and recovery of costs for the interconnection of DG facilities, however, the DPU has also expressed a willingness to consider alternative approaches to its proposal.

In response to industry comments and concerns about the astronomical costs facing projects that are currently part of group affected system operator studies in Massachusetts and are at immediate risk of cancellation, the DPU is considering a smaller scale application of cost sharing proposals, which it is referring to as a "provisional program."

As part of its review of the provisional program, the DPU received a significant amount of detailed information from Eversource and National Grid regarding the CIPs they would likely submit for preauthorization should the DPU approve the program. Of note is that both Eversource and National Grid have proposed that 40-60% of all CIP costs associated with the provisional program be recovered from ratepayers and not recouped from interconnecting customers via CIP fees at a later date. This is because the two utilities have identified that the upgrades in question will create benefits for ratepayers at large and that it would therefore not be appropriate to recover 100% of the upgrade costs from interconnecting customers, even if such costs were recouped through a fixed $/kW fee as the DPU has proposed.

On November 24, 2021, the DPU issued an order approving the establishment of the provisional program. This order directs Eversource and National Grid to submit detailed utility CIP proposals within 40 business days of their completion of each group study that is part of the provisional program. The order also establishes certain parameters that each proposal must meet. Each proposal will be reviewed and adjudicated separately, and it is not certain that the DPU will approve any of the proposals or permit costs of certain upgrades to be allocated directly to ratepayers, however, if implemented as proposed by Eversource and National Grid to date, the provisional program will likely provide a path forward for many facilities whose future is in doubt and serve as a model for conducting long-term system planning and cost allocation going forward.

Case Study: New Mexico Multi-Beneficiary Cost Allocation

On October 27, 2021, the New Mexico Public Regulation Commission (NMPRC) issued an order noticing a proposed rulemaking, which, among other things, included draft language proposing a framework for sharing the costs of distribution system upgrades necessary to interconnect one or more community solar facilities:

1. among several developers using the same distribution facilities;
2. among all ratepayers of the qualifying utility via rate base adjustments; or
3. among ratepayers of the same rate class as subscribers to the community solar facility via a rate rider for that class.[44]

The NMPRC clarified its intent to determine on a case-by-case basis whether such costs should be shared by using the analysis it employs when considering cost sharing or rate basing grid modernization projects, by making a finding that expenditures are:

1. reasonably expected to improve the utility's electrical system efficiency, reliability, resilience and security;
2. reasonably expected to maintain reasonable operations, maintenance and ratepayer costs;
3. reasonably expected to meet energy demands thought a flexible, diversified and distributed energy portfolio;
4. reasonably expected to increase access to and use of clean and renewable energy, with consideration given to increasing access to low-income subscribers and subscribers in underserved communities; or
5. designed to contribute to the reduction of air pollution, including greenhouse gases.[45]

44 New Mexico Public Regulation Commission, Docket No. 21-00112-UT, Order Issuing Notice of Proposed Rulemaking, Exhibit A (issued October 2021), at 3.

45 New Mexico Public Regulation Commission, Docket No. 21-00112-UT, Order Issuing Notice of Proposed Rulemaking, Exhibit A (issued October 2021), at 3.

While the proposed rule has not yet been finalized and there are still many details to be sorted out, it outlines precisely the kind of approach that can help lead to more equitable and cost-effective outcomes for DER developers.

Case Study: New York "Market Driven" and Multi-Value "Utility Driven" Cost Sharing

In 2016, the New York Interconnection Policy Working Group (IPWG) filed a petition with the PSC to implement a cost-sharing mechanism which was incorporated into the Standardized Interconnection Review ("SIR") in 2017 following an order issued by the PSC. A novel concept at the time, the mechanism created a payback mechanism for projects that incurred costly substation upgrades (e.g., transformer bank upgrades, substation protection, etc.) to be reimbursed by subsequent projects based on the pro-rata share of capacity used. While this did alleviate some of the first-mover burden, it provided little certainty for triggering projects and in fact, in the four years of the mechanism's existence did not result in DER customer-funded substation bank upgrades to materialize.

In 2020, the NY IPWG proposed amendments to the mechanism with a "Cost Sharing 2.0" proposal. The PSC issued an order on July 15, 2021, which included a number of significant enhancements to the original mechanism including a broader upfront cost sharing for a wide set of components such as substation equipment, transformers, distribution lines, reconductoring, and underground secondary networks based on kW-AC Capacity. While this cost sharing mechanism continues to cost share primarily between DER interconnecting customers; some unrecovered costs (i.e., those costs not paid for by DER customers) would be funded by the utility and borne by utility ratepayers to an annual cap not to exceed more than two percent of the utility's distribution/sub-transmission electric capital investment budget per fiscal year. The Commission has yet to issue a final order on this topic but is expected to do so in early 2022.

A second component to Cost Sharing 2.0 includes a utility initiated or "multi-value" distribution upgrade process which allows the utilities to conduct a review of opportunities within its annual Capital Improvement Plan process to identify transformer replacements (required for asset condition and reliability reasons) and identify capacity-enhancing upgrades to enable DER. This mechanism creates a pro-rata cost sharing of projects for the *incremental* cost beyond the utility's budgeted capital cost. It will also allow utilities to perform proactive 3V0 upgrades to make substations ready to host distributed energy resources.

Case 16-E-0560 (Joint Petition for Modifications to the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 5 MW or Less Connected in Parallel with Utility Distribution Systems)

Case 20-E-0543 (Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York State Standardized Interconnection Requirements)

Case Study: Federal Energy Regulatory Commission (FERC) Advanced Notice of Proposed Rulemaking (ANOPR)

On July 15, 2021, FERC issued an ANOPR regarding "Building for the Future Through Electric Regional Transmission Planning." This ANOPR considers a wide variety of issues with respect to transmission planning and cost allocation, but at its core is a recognition that existing transmission planning and cost allocation processes are not working as well as they should be with respect to integrating more clean energy on the nation's electric grid. In particular, the ANOPR asks the following questions:

1. Whether the Commission should require transmission providers in each transmission planning region to establish a process to identify geographic zones that have the potential for the development of large amounts of renewable generation and plan transmission to facilitate the integration of renewable resources in those zones;
2. Whether reforms are needed to improve the coordination between the regional transmission planning and cost allocation and generator interconnection processes;
3. How to appropriately identify and allocate the costs of new transmission facilities in a manner that satisfies the Commission's cost causation principle that costs are allocated to beneficiaries in a manner that is at least roughly commensurate with estimated benefits; and
4. Whether participant funding of interconnection-related network upgrades may be proven to be unjust and unreasonable and whether the Commission should eliminate the independent entity variations that allow RTOs/ISOs to use participant funding for interconnection-related network upgrades.

This ANOPR has the potential to result in massive changes to planning and cost allocation procedures at the transmission level that will undoubtedly impact distribution system planning and may create federal precedent that could be applied by states at the distribution system level. While the proceeding is still in an early stage, it is certainly one to be watched closely.

B. Implement Market Based Grid Access Fee

Establishing cost sharing frameworks amongst interconnecting DERs and customers at large is a good start to addressing the challenges of deploying DERs under the cost causation principle, but cost sharing alone likely cannot move states past certain major DER integration challenges. By changing utilities' incentive structure and moving to a more market-based structure, utilities can be enabled and required to rethink how customers access the grid through a simplified interconnection access charge. A grid access fee would be determined by a robust stakeholder process and overseen by state regulatory bodies. It would span a number of focus areas, including the distribution system planning process, integrated resource planning, state energy equity goals, and state electrification needs.

A grid access fee fits into a systematic overhaul of utility planning because it requires long-term planning over a wide customer base, an effort at which utilities typically excel. The concept is not dissimilar to other programs and rate structures that utilities manage. There are a number of ways a grid access fee could be structured. Whichever form it takes, it is important to create and update the fee based on a wide range of stakeholder input. Cost signals are important to creating a robust, high-DER grid because they drive developers to areas of greatest need.

As we plan for electrification, where we site solar will change. Electrification and planning will create market signals to drive developers in the right direction. A market-based approach will allow utilities to guide DER development on their grid based on their advanced planning efforts. This type of market-based fee would also be beneficial for a state's electrification efforts. For example, if a utility's coordinated planning shows that a school bus charging station is being planned in a particular location, the utility could adjust the grid access fee downward in that area to encourage solar and storage development that would coincide with the EV charging needs. These interconnection market signals would be amplified through future DER revenue mechanisms (such as tariffs or programs), magnifying their effect and allowing utilities to better direct DER siting on their grid. Such a mechanism would also enable utilities to make necessary and proactive grid upgrades on their own timeline, without the complex and lengthy interactions that typically transpire between their engineering staff and clean energy developers.

6. Invest in Grid Modernization Technologies that Support DER Integration

Utilities very often operate electric distribution systems that do not employ the most current technologies available and as a result, are frequently not optimized to meet a utility's core functions, such as ensuring reliability, affordability, efficiency, or integrating new resources. Investments in new grid infrastructure and software can help automate components of the electric grid, making it more reliable and resilient. Additionally, implementing new technologies and software will permit a tremendous amount of information to be shared amongst different parties, providing utilities with more insight into the operation of their distribution systems and customers with more insight into their own energy use patterns. Lastly, entities such as DER owners be provided with more visibility and transparency into the operations of the electric power system. This is an essential benefit of deploying these technologies, as it will permit DER developers to properly size and site projects in locations that are lowest cost and provide the most benefits to the electric grid and ratepayers. If deployed and utilized correctly, grid modernization technologies can transform the electric grid and create many layers of benefits for customers, utilities, policymakers, and industry.

Recommendations

State legislatures and regulatory bodies should direct and incentivize distribution companies to make investments in grid modernization technologies, software, and tools that help facilitate DER integration and allow DERs to provide the most value to the grid possible. This can be accomplished through directing utilities to recover such costs through traditional distribution rates, through a specialized recovery mechanism, or some combination of the two. It can also be accomplished by establishing performance metrics and/or PIMs associated with making these types of investments. While there are a myriad of grid modernization technologies and tools that should be considered, with respect to tools that facilitate DER integration, at a minimum, state regulatory bodies should direct utilities to make grid modernization investments in the following areas:

A. ADMS, SCADA, and Data Management Tools

A foundational grid modernization investment to support DER integration and a myriad of other items is the establishment of Advanced Distribution Management System (ADMS), Supervisory Control and Data Acquisition (SCADA) systems, and data management tools to operate them. Investments in this area will provide utilities with significantly more real-time information and control over the operation of their system at a more granular level than they have ever had previously. Through the implementation on these measures, distribution system operators will be able to better understand power flows, permitting more detailed and accurate analyses of system conditions and operating limits, which in turn helps facilitate other measures that allow for higher penetrations of DERs and/or identifies areas where further investment in the distribution system is needed. Additionally, these tools provide benefits well beyond facilitating more DER integration, such as allowing for greater automation of the distribution system, faster outage restoration, and allowing utilities to operate their systems with greater efficiency and to respond to emerging issues more quickly.

Case Study: San Diego Gas & Electric DMS and SCADA Deployment

From 2007-2012, San Diego Gas & Electric (SDG&E) began efforts to build out DMS related infrastructure, initially focusing on deploying and integrating an outage management system (OMS) with its DMS. From 2013-2015, SDG&E conducted the second phase of its implementation plan, which was focused on deploying network management system (NMS) tools such as power flow analysis, suggested switching, FLISR (fault location, isolation, and service restoration), and fault location analysis. This second phase was made possible by the deployment of two-way SCADA integration and data management tools that allowed SDG&E to collect and synthesize data on system operations. Importantly, the second phase included an effort to integrate DERs on the system, focusing on forecasting solar performance by working with local meteorologists and the NMS tools that were developed.

The tools developed rely on an enormous amount of data that requires validation and testing to work properly but have been effective in predicting where system constraints may occur due to weather related fluctuations prior to their occurrence. The system is capable of accounting for "hidden load" that was being met with solar generation before cloud cover reduces it and allows SDG&E to effectively address these fluctuations in demand and to better integrate the more than 1,100 MW of rooftop solar deployed in its territory.

As discussed above, deploying DMS, SCADA, and data management tools are foundational investments that provide a utility with greater visibility and insight into the operation of their grid. Given their collective ability to address issues such as outages and to help the grid self-heal, these investments provide benefits far beyond assisting in the integration of DERs. Accordingly, they have been made at some level in many jurisdictions across the US already, including those with low penetrations of solar, however, this example from SDG&E is a good case study in how these foundational grid modernization investments can specifically assist utilities in integrating large quantities of DERs on their distribution systems.

B. Voltage and Volt-ampere Reactive Optimization (VVO)

Because DERs are often intermittent sources of generation whose real-time power output can be dramatically altered by rapid shifts in weather changes (e.g., passing clouds, changes in wind speeds, etc.), they can present challenges to utilities and other grid operators that are required to maintain certain conditions on the electric grid. For example, a sudden decrease in the output of DERs may lead to voltage flicker, when voltage rapidly increases or drops along distribution feeders and can result in voltage levels that temporarily fluctuate outside of acceptable ranges. However, this can be mitigated by permitting utilities to make investments in VVO technologies (e.g., load tap changes, voltage regulators, and capacitor banks) installed along feeder circuits, and integrating these into distribution management systems. These investments not only help ensure that a larger quantity of DERs can be integrated into the distribution system by more effectively managing power quality but can also provide broader benefits by improving the overall efficiency of the electric grid, reducing system line losses and minimizing demand through conservation.

Case Study: Pacific Gas & Electric VVO Smart Grid Deployment Project

On November 21, 2011, PG&E filed an application requesting authorization to recover costs for implementing six Smart Grid Deployment Projects, one of which was a VVO pilot that called for deploying VVO on as many as 12 distribution feeders in different parts of PG&E's service territory. One of the key objectives of this pilot was to test and demonstrate the ability of VVO to "reliably and cost-effectively integrate and manage the variations in voltage associated with distributed generation,"[46] enabling higher penetrations of intermittent distributed generation to be deployed. The pilot was ultimately approved (with certain conditions) in an order issued by the CPUC on March 21, 2013.

PG&E estimated that the VVO pilot will ultimately result in a benefit/cost ratio of 1.5 - 2.7 for consumers over a 15-20 year period, with benefits primarily being derived from energy efficiency savings (e.g. peak demand and total load reductions resulting from more efficient operation of the distribution system). While the ability to integrate additional DERs as a result of the VVO deployment is difficult to precisely quantify, PG&E noted that there was a significant improvement in its ability to provide more dynamic voltage control with VVO. In particular, the VVO was able to address voltage rise resulting from reverse power flow from DERs, flattening and lowering the voltage profile of circuits on which it was deployed.

In a detailed report filed with the CPUC on December 30, 2016,[47] PG&E summarized the results of the pilot to date and made recommendations for further deployment of VVO to 510 of PG&E's 3,200 distribution circuits. PG&E also recommended that the deployment of VVO be sequenced after the deployment of ADMS and SCADA systems in order to yield the greatest benefits.

C. Distributed Energy Management System (DERMS)

Building on a foundational investment in ADMS, utilities should also consider making investments in a DERMS that integrates data points from multiple different processes (interconnection queues, ADMS, load flow analyses, hosting capacity analyses, etc.) and allows utilities to better understand the operation of DERs on their distribution system. A DERMS can provide significant benefits, chief among which is permitting two-way communication between the utility and individual DERs, allowing utilities to optimize the performance of DERs by allowing for centralized management and dispatch of the assets. The integration of datasets and the collection of real-time performance data through the implementation of a DERMS also allows for much more detailed and accurate information about the distribution system to be provided to DER providers seeking to interconnect, saving time and money by streamlining the interconnection process and likely reducing the submission of speculative applications.

Case Study: PG&E DERMS Demonstration

While several jurisdictions have begun to explore the deployment of a DERMS, actually doing so

46 PG&E's Advice Letter 4227-E, *Smart Grid Pilot Deployment Projects Implementation Plan, Pursuant to D.13-03-032*, submitted for filing on May 22, 2013 and approved effective June 21, 2013 by the CPUC's Energy Division, at 15-16.

47 See p. 128-215 of the PDF.

requires some foundational investments in ADMS and SCADA to be deployed first. As a result, there are relatively few examples of a DERMS being deployed and fully operational in the US. One such example though is a pilot conducted by PG&E in San Jose, California between 2016 and 2018.

The objective of the demonstration was to "demonstrate new technology to monitor and control DERs to manage system constraints and evaluate the ability to manage a 'fleet' of DERs to provide distribution grid services" in an effort to prepare for higher penetrations of DERs that are expected to be deployed in the coming years.

Ultimately, PG&E selected three distribution feeders connected to a single substation that served approximately 9,500 customers. These feeders were then further divided into six "nodes" and a simulated distribution market was established to demonstrate the following use cases:

- Provide situational awareness;
- Manage equipment capacity constraints and reverse power flow;
- Mitigate voltage issues with real-power output;
- Mitigate voltage issues with reactive power;
- Enable economic dispatch of distributed generation and energy storage;
- Provide operational flexibility; and
- Enable limited multiple-use applications of DERs.

GE Grid Solutions was selected to develop a DERMS that was tasked with managing 124 kW of residential PV coupled with 66 kW/264 kWh of residential storage at 27 homes, 360 kW/720 kWh of commercial storage at three commercial locations, and a 4 MW/28 MWh PG&E-owned utility-scale battery. PG&E partnered with Tesla to coordinate the residential DERs and ENGIE Storage to coordinate the commercial DERs.

The demonstration resulted in positive outcomes for each use case tested, but did reveal a number of challenges and areas for improvement, such as the ability to scale up, standardization challenges (e.g. lack of common software and protocols amongst DERs), targeting/recruitment of DERs, properly valuing DER-provided services, distribution market design challenges, and issues pertaining to operational flexibility.

More information on this demonstration can be found in the following useful NREL report that summarizes the effort:

Coordinating Distributed Energy Resources for Grid Services: A Case Study of Pacific Gas and Electric

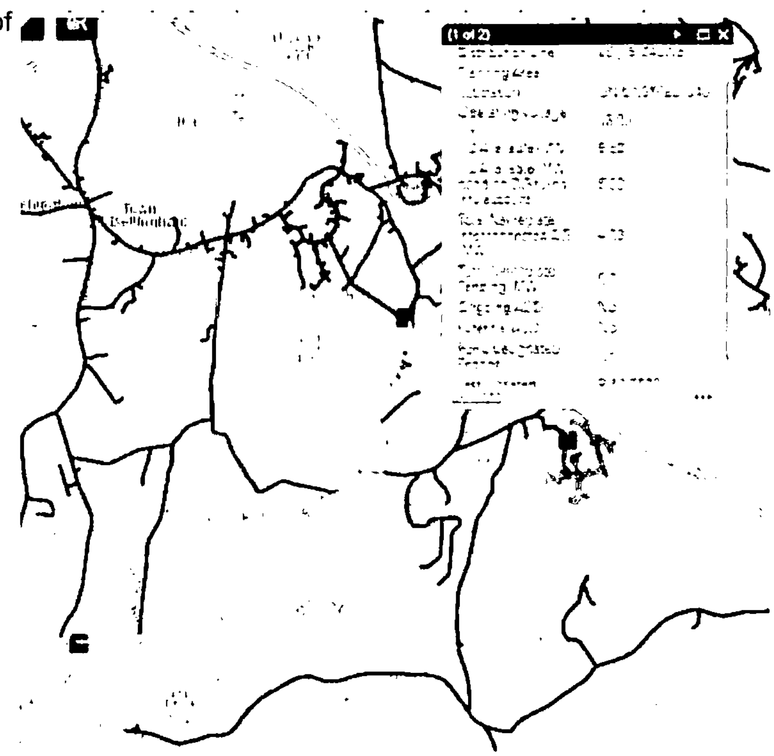
D. Hosting Capacity Analyses and Maps

Utilities should be required to develop and maintain up to date hosting capacity analyses, which should ideally be accompanied by hosting capacity maps. Accurate and detailed maps that are updated regularly can be very valuable in conducting system planning processes and helping DER developers in identifying the best locations to site new facilities. They can also be extremely useful tools for utilities when conducting system planning exercises. Once developed, such analyses should be updated frequently and should contain as much information as possible. However, the creation of such analyses and corresponding maps is often an iterative process, which typically starts with the inclusion of basic information and over time is expanded as new tools and technology allow for utilities to create more detailed analyses. The gold standard of hosting capacity analyses and maps should include information that is timely and relevant to grid planners and stakeholders alike to assess interconnection viability and grid conditions. Grid modernization technologies such as those described above can be enormously important in the development of more advanced and useful hosting capacity analyses. In developing hosting capacity maps, the ultimate objectives for utilities and regulators should be to move towards a real-time, dynamic interface that provides at least the following information:

- List of Penetration Ratio on each utility's feeder and each utility substation;
- List of Hosting Capacity on each utility's feeder;
- Quantity of "closed" feeders and substations;
- Quantity of substations that have regular backfeeding from distribution to transmission; and
- Aggregate list of connected Distributed Energy Resources at each utility substation as compared to transformer ratings.

IREC has done a significant amount of analyses and maps recently produced the following helpful resource on developing hosting capacity maps:

Key Decisions for Hosting Capacity Analyses



Online Map with Pop-Up Boxes | *Source: National Grid (MA)*

Case Study: Massachusetts Hosting Capacity Maps

On December 26, 2019, DPU staff issued a straw proposal, which included a proposal to require the investor owned utility companies to publish online hosting capacity maps that included, but were not limited to, the following information: "[DG] saturation by location, circuit, and/or substation; potential or on-going affected system operator ("ASO") studies; and current jurisdiction of circuits, i.e., Open Access Transmission Tariff ("OATT") or state/EDC." Following a public comment period on the straw proposal, on September 16, 2020, the DPU issued D.P.U. 19-55-D, which, among other things, adopted the staff straw proposal, and directed the investor owned utilities to produce online maps by November 16, 2020, which were to include at least the following for each feeder line displayed on the maps:

1. operating voltage (kV);

2. hosting capacity available (MW);
3. total nameplate interconnected DG (MW);
4. total nameplate pending DG (MW);
5. potential or on-going ASO studies;
6. the current jurisdiction of circuits (i.e., federal or state); and
7. date last updated.

The DPU further directed the utilities to update maps at least monthly and to explore including adding to the maps all information that is included in Pre-Application Reports provided to customers seeking to interconnect in a particular location. While the maps were developed and publicly available ahead of schedule, the progress made by each utility towards achieving the additional objectives outlined by the DPU (as well as projected and incurred costs to date) was detailed in reports filed by each utility in May 2021.[48]

Case Study: Minnesota Hosting Capacity Analysis

In June 2015, the Minnesota state legislature passed a law requiring Xcel Energy to conduct a study identifying interconnection points on its distribution system for small-scale distributed generation and necessary upgrades to support continued distributed generation development. On June 28, 2016, pursuant to this statutory directive, the MN PUC issued an order requiring Xcel Energy to file its initial hosting capacity analysis by December 1, 2016, with analysis of each feeder for distributed generation up to 1 MW and potential distribution upgrades necessary to support expected distributed generation.

Following the submission of Xcel Energy's initial hosting capacity analysis, the MN PUC issued a subsequent order on August 1, 2017, requiring that Xcel Energy to provide:

1. a subsequent report that is detailed enough to provide developers with a reliable estimate of the available level of hosting capacity per feeder and to inform future distribution system planning efforts and upgrades necessary to facilitate the continued integration of distributed generation;
2. a color-coded, map-based representation of the available hosting capacity down to the feeder level;
3. hosting capacity analysis results in downloadable spreadsheet file formats;
4. provide data used in the modeling, including assumptions and methodologies,
5. provide information on the accuracy of the report information; and
6. provide such a report by November 1st of each year.[49]

Since the issuance of the 2017 order, the MN PUC has issued four subsequent orders that have provided further directives to Xcel Energy with respect to the content of their annual hosting capacity analysis they must file each November:

July 19, 2018 Order Accepting (2017) Study and Setting Further Requirements
August 15, 2019 Order Accepting (2018) Study and Setting Further Requirements

48 These progress reports can be found at the following links: Eversource, National Grid, Unitil, Unitil: Attachment A

49 *In the Matter of Xcel Energy's Biennial Transmission and Distribution Plan: Distribution System Study – Hosting Capacity Report*, Docket No. E-002/M-15-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report (August 1, 2017), at 5-6.

[July 31, 2020 Order Accepting (2019) Study and Setting Further Requirements]
[November 9, 2021 Order Accepting (2020) Study and Setting Further Requirements]

Case Study: New York Hosting Capacity Analysis and Maps

On March 9, 2017, the NY PSC issued an order that, among other things, directed the electric utilities it regulates to develop a hosting capacity analysis for all circuits at and above 12kv by October 1, 2017. In issuing this directive, the NY PSC recognized that "the availability of hosting capacity data is one of the most fundamental elements needed for enabling DER development," that it was generally supportive of the phased approach to developing hosting capacity tools outlined by the utilities, but that "their progress has been unacceptably slow and not supportive of the industries' needs."[50]

The NY PSC also noted the importance of improving hosting capacity maps and the data accompanying them, highlighting the discrepancies in the quality of data provided to customers by different utilities. To address this, they directed the utilities to work with stakeholders to identify content to be provided on the maps, specifically mentioning data such as the rating of a circuit, historical circuit loading data, and forecasted peak loads. Lastly, the Commission directed that hosting capacity values be updated at least annually and data tables accompanying maps to be updated at least monthly, with efforts to be made to update maps more frequently as experience is gained.

Selected List of Publicly Available Hosting Capacity Maps by State and Utility

The following is not an exhaustive list of existing hosting capacity maps, nor does it constitute an endorsement of any of these maps, but rather represents a collection of different hosting capacity maps that have been developed by utilities in different jurisdictions. More links to existing hosting capacity maps can be found on IREC's website.

Jurisdiction	Frequency of Updates	Links
California	Monthly	Pacific Gas & Electric
		San Diego Gas & Electric
		Southern California Edison
Hawaii	Daily	HECO (Hawaii)
		HECO (Maui)
		HECO (Oahu)
Massachusetts	At least Monthly	Eversource (Eastern MA)
		Eversource (Western MA)
		National Grid
		Unitil
Minnesota	Monthly	Xcel Energy
New York	Annual	New York Utilities
Oregon	Monthly	PacifiCorp
Rhode Island	Annual	National Grid

50 New York Public Service Commission, Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016), at 14.

7. Reduce Unnecessary Barriers to Interconnection

For utilities, it takes experience and collaboration to become comfortable with new technologies and interconnection solutions. There are many redundancies built into the grid to ensure safety and reliability but some of these redundancies are unnecessary and extremely costly. State regulators, utilities, developers, and consultants have embarked on innovative pilot projects around the country to identify least cost methods of interconnection that preserve the safety and reliability of the electric grid and improve grid access to customers. It is important to continue to build upon these studies and, more importantly, to implement these piloted solutions when they prove to be cost-effective and safe.

Project developers also do not have enough information about the state of the grid to make informed decisions about project siting and development. This results in situations where developers will submit speculative applications to gather information, clogging up interconnection queues and tying up staff resources. This often wastes time and money for both the developer and the utility and delays the integration of additional DERs that must wait in line behind applications that may never have been submitted in the first place had more information been publicly available. Utilities and regulatory commissions can aid in this process by making interconnection study and distribution system information available, at least in a limited format, but ideally at the most granular and real-time level possible. Many states have incorporated pre-application reports into their interconnection processes that may provide some information, albeit limited and static, to aid in informed decision making.

Recommendations

Instead of overbuilding the electric power grid to meet a few hours of peak demand requirements in a year at great cost to ratepayers, when implemented correctly, DERs and smart grid technology solutions can lower overall costs and provide energy when and where it is needed. These solutions need to be coupled with smart sensors and grid communication technology that will enable the grid to become automated over time. Some key areas of innovation include:

A. Establish Open and Transparent Interconnection Queue Process for Applicants

Typically, developers have no insight into any previously completed interconnection studies that have already been completed on a given circuit, and no access to modeling data that may support their own analysis prior to making an application to the utility. Adding additional data transparency mechanisms would reduce duplicative efforts for utilities and reduce speculative interconnection applications. It's worthy to note that this information is available, based on information sharing requirements, for RTO administered interconnection studies today. As noted above, well designed hosting capacity maps can also significantly improve the availability of this information.

An applicant should be able to apply to the utility to interconnect a solar generator and have a view of both the transmission and distributed planned projects on all distribution, sub-transmission and transmission level infrastructure that will impact that application. Study processes should also be phased, with subsequent studies providing additional levels of detail at increasing cost, if needed, based on the level of data required. All applicants should receive study results within a reasonable timeframe and have ample time to assess results before moving to the next stage. Utilities also need clearly defined processes for when an applicant drops from the queue.

Many jurisdictions have some level of data regarding interconnection queues that is publicly available. Some of the best examples of such types of queues come from RTOs, which maintain queues for projects seeking to interconnect at the transmission level:

CAISO
ERCOT
ISO-NE
MISO[51]
NYISO
PJM
SPP

While most states and distribution utilities still have a long way to go when it comes to transparency and accessibility of information related to interconnection queues, certain states and utilities are worth highlighting for the accessibility, quantity, and type of information they make publicly available:

Duke Energy Interconnection Queue Webpage (North Carolina and South Carolina)
Hawaiian Electric Companies
Massachusetts Interconnection Webpage[52]
New York Interconnection Queue Webpage
Xcel Energy (Minnesota)[53]

B. Increase Transparency of Equipment Costs

All too often, costs of specific equipment upgrades are not transparent and are inconsistent from one project to another or from one utility to another. The cost to upgrade specific types of utility infrastructure to interconnect at a particular site must be transparent, including all required devices, materials, labor and overhead. The upgrade costs must be attributable to the actual cost of connecting the specific DER facility at that specific location. Requiring utilities to provide estimated ranges of the costs of common upgrades is one way to increase the transparency and availability of this information for both DER developers and regulators.

In several jurisdictions, utilities have either taken it upon themselves or have been directed by their regulators to publicly provide transparency around the costs of standard equipment upgrades that are often triggered by interconnecting facilities. These cost estimates are often highly variable as they can be situation specific, but providing this information creates significantly more transparency for all parties involved in the interconnection process and allows for interconnecting customers to potentially estimate upgrade costs themselves. It may also permit regulators to examine inconsistencies in costs assessed from one utility to another and examine the reasons why such discrepancies exist. The following represent a handful of examples of utilities that have publicly provided such cost estimates.

51 The MISO queue is particularly noteworthy for its transparency as it contains a wide range of information, including copies of public versions of studies for individual projects listed in the queue, a map of all resources seeking to interconnect that is updated every 30 minutes, and another map highlighting points of interconnection where congestion is likely to exist.

52 See data under Utility Reporting & Circuit Analysis for Locational Value heading.

53 Click on "Public Distributed Energy Resources (DER) Queue Report" to download current and historical reports.

California

PG&E Unit Cost for Interconnection Facilities
Southern California Edison Unit Cost Guide

Colorado

Xcel Energy General Cost Outlines

Massachusetts

Eversource Project Cost Guide
National Grid Project Cost Guide

New Jersey

Jersey Central Power & Light

C. Apply Best Practices and Transparency Regarding Technical Standards

Utilities take different approaches to studying interconnection applications. Some are based on national best practices and research and others are based on decades-old thinking that often requires unnecessary equipment, time, and expense. To ensure cost-effective DER integration, all utilities should be employing the most up-to-date technical standards possible and conducting open and transparent processes to inform updates to utility or region-specific standards to balance grid reliability and interconnection improvements. Importantly, resource-limited state regulators have often deferred to utilities regarding technical issues, allowing utilities to implement outdated standards that may even be inconsistent between utilities within the same state. Standards development and implementation is a significant focus area for utilities and state regulators to achieve a cost-effective clean and reliable grid. A number of interconnection working groups, regulatory proceedings, and national labs have come up with some creative solutions to access capacity constraints or identify least-cost equipment solutions without compromising safety and reliability.

State regulatory bodies should create a framework, with oversight, to ensure that utility technical standards are consistent, justified, and implemented in a transparent manner. Of most note, industry wide standards such as those developed by the Institute of Electrical and Electronics Engineers has published and updated IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems) provide a set of criteria and requirements for the interconnection of distributed generation resources into the power grid that are technology-neutral, applicable to projects as large as 10MVA and can be universally applied. State regulatory agencies should track the development of new standards and periodically ensure that utilities in the state are operating under the most up-to-date IEEE standards possible. Other notable technical standards and practices are inconsistent between states and utilities and include broad issues such as the application of interconnection screens, study methodology, and feeder limits, but also interconnection equipment requirements in response to issues such as ground-fault overvoltage or islanding.

Utilities commonly have generator interconnection handbooks, bulletins, or standards that govern utility specific requirements to interconnect to the distribution system. Often these are not frequently updated, informed by stakeholder feedback, or approved by a regulatory body. In addition to a technical working group that could serve a key purpose in this effort, the Sandia National Laboratories, the National Renewable Energy Laboratory, the National Institute of Standards and Technology, and Argonne National Laboratory are examples of organizations that can help with the adoption of best practice technical standards across DER markets. Utilities can also lean on the Electric Power Research Institute (EPRI) to help with the adoption of current technical standards.

Historically, many large projects have required the installation of Direct Transfer Trip (DTT) equipment, due to utility requirements around anti-islanding, despite the fact that certified inverters already perform this function. DTT can add hundreds of thousands of dollars onto the price of DER interconnection, and many months of additional construction time. There are a number of effective work-arounds for DTT requirements that can save money and regulators should require utilities to adopt them. Some options include:[54] [55]

- Distributed Generation Permissive, which sends a digital signal with the DER connection to the grid, assessing the formation of an island and the need to trip.
- Reliance on UL 1741 inverters, coupled with reclose blocking.

It is equally important for the state to create both policy and technical working groups (or a single group tasked with both) made up of regulatory agency staff, utilities, project developers, and other stakeholders with the technical expertise to help effectively implement technical standards. As described above in Section V.2., many states have created ongoing interconnection technical and policy working groups, which have been instrumental in advancing interconnection policy to keep up with changing realities.

Finally, it is important that utilities have a forum in which they can share information on best practices, based on experience and case studies. One option could be DOE's Office of Energy Efficiency and Renewable Energy's Federal and Utility Collaboration Working Group, but other organizations with a regional or national footprint could facilitate such a forum as well.

Case Study: California Revisions to Anti-islanding Screen Parameters

On June 3, 2021, the CPUC issued an order addressing several issues including preventing unintended islanding. The CPUC adopted the following changes to anti-islanding screen parameters to reflect research on islanding risks when using UL 1741-certified inverters to avoid unnecessary mitigations:

- Requiring protective equipment for machine generators, allowing customers to conduct independent unintentional islanding studies;
- Establishing a working group to study unintentional islanding formation concerns;
- Creation of new PG&E anti-islanding screens; and
- Development of a guidebook on anti-islanding options.

Case Studies: IEEE 1547-2018 Implementation

54 T&D Article on National Grid's Blueprint for DG Interconnections

55 Sensus White Paper on Mitigating the Impact of Unintentional Islanding on Electric Utility Transmission Systems from Distributed Energy Resources

While a significant majority of states have not yet even begun a process to update their interconnection rules to require that DERs utilize inverters certified to the IEEE 1547-2018 standard, there are a few jurisdictions that have begun this process.

California

While California had previously adopted certain advanced inverter requirements to be adopted under its statewide interconnection rules, it officially began the process of updating its interconnection requirements to adhere to the IEEE 1547-2018 standard in 2020 as part of docket R.17-07-007.

Hawaii

Similar to California, Hawaii already required advanced inverters that had been tested to UL 1741 Supplement SA, but has taken further steps to harmonize requirements with those in IEEE 1547, requiring all inverters to meet IEEE 1547-2018 standards beginning on January 1, 2022.

Maryland

In 2020, Maryland updated its interconnection rules with a requirement that DERs must use IEEE 1547-2018 certified inverters to be eligible for interconnection beginning on January 1, 2022.

Massachusetts

Massachusetts has been working since early 2020 to implement IEEE 1547-2018 requirements through its interconnection rules. The work in Massachusetts is primarily being conducted via the Technical Standards Review Group (TSRG),[56] which meets quarterly and has been taking steps towards implementation of the standards via the utilities' Common Technical Standards Manual. While no specific date has yet been set for implementation, it is worth noting that ISO-NE (which the entirety of Massachusetts is located within) has set an effective date of April 1, 2022, for IEEE 1547-2018 standards to take effect.

Minnesota

Minnesota was the first state to take a comprehensive look at this issue and integrate IEEE 1547-2018 requirements in its State of Minnesota Technical Interconnection and Interoperability Requirements (TIIR). That said, Minnesota waited to set a specific date on which the TIIR would take effect as it was not clear at the time that certified equipment was available on the market.

One challenge with the implementation of the IEEE 1547-2018 standard is that it set forth standards for inverters but did not include testing procedures for certifying inverters to the standard. As such, there was a degree of urgency from entities such as the North American Reliability Council (NERC) and RTOs to implement the standards, but a lack of clarity around how to ensure the equipment was compliant.

56 See meeting agendas posted to TSRG website for more details.

With the issuance of IEEE 1547.1-2020 in May 2020, testing procedures for certification became available, which means that by 2022, officially certified equipment should be commercially available. While this resolves many implementation challenges, there may still remain a substantial disconnect between state level standards and RTO level and national standards, so it is incumbent upon states and distribution utilities to take steps to implement IEEE 1547-2018 standards in state level interconnection procedures as expeditiously as possible. A recommended approach is to follow suit of other states by convening stakeholders with relevant technical expertise to discuss implementation challenges and build consensus around how to best move forward. The establishment of a technical working group is an ideal way to accomplish this objective.

D. Enable Dynamic Curtailment and Self-limitation

In the absence of a fully developed and integrated DERMS system utilities are exploring localized opportunities to implement operational tools to enhance and optimize the amount of available capacity for a DER system or avoid costly system reinforcements. This allows for the grid to automatically adjust DER export to the grid, for example during periods of high generation and low load, based on enhanced communication features between DER in-front and behind-the-meter equipment and utility side equipment. Various utilities in New York and Massachusetts have proposed and are piloting these types of technologies.

Additionally, another option that is available to help more facilities operate under hosting capacity constraints is for facilities to voluntarily agree to operate their facilities in a manner that avoids such constraints. For example, by adjusting inverter settings, a solar facility can potentially avoid contributing to overgeneration concerns during shoulder months when solar production is high, and demand is low by reducing its maximum output. During summer and winter months, these settings can be adjusted back to allow the facility to operate at its full potential. While such solutions are not necessarily ideal in some respects, they do permit higher quantities of DERs to be integrated in the near term while avoiding or deferring potentially costly investments in the bulk power system that would otherwise be necessary to accommodate the interconnection of such facilities.

<u>Case Study: California DER Self-Limiting to Avoid Upgrades</u>

On January 21, 2021, as part its rulemaking on interconnection,[57] the CPUC issued an <u>order</u> correcting errors in an earlier <u>order</u>, and which adopted recommendations from California's Interconnection Working Groups #2, # 3, and the Vehicle-to-Grid (V2G) subgroup. Specifically, the CPUC adopted a proposal that would allow a DER to be evaluated under a limiting generation profile in order to perform within hosting capacity constraints. The proposal allows a customer to utilize a smart inverter's ability to increase its output during months of the year (replacing seasons in the utility proposal) where a higher level of Interconnection capacity is available based on the ICA. The monthly real power limit would include a 10 percent buffer but the CPUC may revisit the issue after 18 months of experience with the system. The proposal allows for the following:

a. Customer submits a Limited Generation Profile with their application, which may include generation up to the 80 percent Integration Capacity Analysis-SG value published by the utility and submitted in a standard 288-hour format;
b. Customer agrees to enable smart inverter functionality to ensure actual operations conform to

57 See docket R.17-07-007.

submitted Limited Generation Profile;

c. Customer agrees to follow future reductions to generation profile, with the utility determining such reductions within defined circumstances (e.g., future grid conditions change hosting capacity).

E. Allow Interconnecting Customers to Self-build System Upgrades

Often due to the lack of utility incentive, interconnecting customers and utilities are misaligned on the costs and timelines to perform utility construction work necessary to interconnect projects and the speed at which a solar facility can be ready to interconnect to the grid. Interconnecting customers should be able to contract and construct the necessary electric grid upgrades to drive down costs and complete certain upgrades on the utility side of the meter in coordination with the electric utility. This can be done with utility guidance and according to the same standards they use for third-party contracted resources. Utilities can also have oversight over this process to ensure that the upgrades are constructed to their specifications and performance standards.

Case Study: FERC Orders 2003 and 845

A feature of the federal-standard interconnection practices has included an option for interconnecting customers to build upgrades since the issuance of Order 2003, which allowed for customers to construct upgrades in the event utilities cannot meet a customer's requested schedule. This was revised by the issuance of Order 845 in 2018 to provide the customers the unilateral right thereby seeking to improve the timeliness of generation development, costs to customers, and market competition. This option allows interconnection customers the option to build their own interconnection facilities including generator tie-lines, interconnection substations, and standalone transmission upgrades with appropriate safeguards such as review and approval of engineering designs, equipment tests, etc. While these rules are specific to transmission interconnections, similar rules could easily be applied to distribution level interconnections as well.

F. Standardize Application Processes

At a minimum, state regulatory bodies should require the electric utilities they regulate to take steps to develop standardized electronic interconnection application processes, preferably ones that are similar for all utilities operating in their area of jurisdiction. Ideally, however, an entity such as the DOE would consider creating an off-the-shelf, standardized interconnection application processing software that utilities across the US can integrate into utility software to facilitate application processing in a consistent manner across many jurisdictions.

Case Study: SolarAPP+

Working through NREL, the DOE has recently launched "a collaborative effort with key code officials, authorities having jurisdiction, and the solar industry to develop standardized plan review software that can run compliance checks and process building permit approvals for eligible rooftop solar systems." Among other things this software is designed to be integrated with existing software, automate plan review, permitting approvals, and track a project's progress through the review process. While it is not precisely the same as an interconnection application procedure, this could serve as a model for something similar to be developed for electric utilities.

SolarAPP+ Website

G. Permit Information Sharing and Mitigation Review Within Studies

Generally, interconnecting customers only receive information regarding system limitations and constraints as an outcome of a final study process and may not be able to implement solutions to modify their project and mitigate system issues at that time without significant consequences. This is because the types of meaningful project changes that could improve interconnection feasibility and impacts to the grid are very often treated by utilities as material modifications to an application that require re-entry into the interconnection queue process from the very beginning, resulting in a loss of queue position and the need for a complete re-study. Flexibility should be provided for DERs to incorporate technology or operating changes to provide system benefits and reduce cost by allowing for the identification of system constraints (thermal limits, flicker issues, etc.) and potential mitigations. Such a change in utility procedures could likely lead to more efficient and fair outcomes for DER developers.

H. Incorporate Energy Storage Into Interconnection Rules

In many jurisdictions, interconnection rules still do not explicitly address the process of interconnecting energy storage systems. Given the unique nature of how such systems operate and how common they are increasingly becoming, it is necessary to explicitly define what they are and incorporate rules and procedures that are specific to them, which has been done in several jurisdictions. While there may still be some matters that a regulator must adjudicate with respect to their inclusion in interconnection rules, in general, there are plenty of opportunities for utilities and DER developers to find common ground on how best to implement rule changes to incorporate storage. In most cases, the catalyst for such a change occurring is simply the regulator taking a proactive step by directing parties to work together to develop consensus recommendations on the language and procedures necessary to do so.

A handful of states have formally incorporated definitions of energy storage and other related provisions into their interconnection rules (e.g., Arizona, California, Colorado, Hawaii, Maryland, Nevada) and others have processes underway to do so. While those states could certainly be looked to for lessons learned, helpful guides for states and utilities considering incorporating energy storage into distribution level interconnection procedures have been published by both the Energy Storage Association, in its January 2018 paper on Updating Distribution Interconnection Procedures to Incorporate Energy Storage, and IREC, through the 2019 version of its Model Interconnection Procedures.

8. Improve Coordination with RTOs

As more states reach higher DER penetrations, impacts are beginning to be seen on the transmission system, necessitating the need for transmission level impact studies and upgrades. This means that going forward, there will need to be increased coordination with RTOs to ensure efficient and cost-effective DER project development. Currently the system construction timelines between RTOs, transmission owners, and distribution companies are not coordinated. Additionally, study and construction timelines at the transmission level are not enforceable (particularly by state jurisdictional bodies such as utility commissions), leading to a significant lack of certainty with respect to both cost and timeframes, which can easily derail project development. This issue is particularly problematic in Northeast states like Maine, Massachusetts, and Rhode Island, but it is likely only a matter of time before these issues begin to surface in other regions as well.

Some of the exacerbating factors that developers face include:

- Lack of clarity regarding whether a distribution line to which a facility is interconnecting is FERC jurisdictional or is subject to state level interconnection rules;
- Transmission level impact studies (and upgrades) being triggered after a project has executed an interconnection services agreement and made distribution level upgrade payments to a distribution company (in some cases this has occurred after a project has been fully constructed); and
- No clear authority to address certain cross-jurisdictional issues.

There are many examples of (1) the lack of communication between RTOs, transmission owners, and distributed system operators causing years of delays and (2) multiple studies being required at both the distributed and transmission level, resulting in the loss of hundreds of thousands of dollars for DER developers for what are often unnecessary and repetitive study fees.[58]

Recommendations

The rapid pace of DER and demand growth means that as traditional, utility-driven, planning practices are outpaced, new planning approaches must be collaborative and flexible enough to grow with a quickly changing grid. It is critical to balance transmission level upgrades, which are often extremely time consuming and expensive, with distribution level upgrades that cannot proceed without the former being complete. Joint planning between RTOs and utilities is vital to ensure clean energy is brought online seamlessly at both the distribution and transmission level. This can be supported by the following:

A. Establish Collaborative Stakeholder Forums

RTOs and other transmission level operators should consider establishing forums or working groups through which impacted stakeholders (i.e., transmission owners, distribution companies, DER developers, and state agencies) can gather to discuss transmission planning issues arising from DERs seeking to interconnect at the distribution system and/or utility managed distribution system planning processes. Creating regular forums to discuss these topics will help head off issues as they arise, saving all parties time and money and by fostering better coordination and establishing lines of communication.

There are currently no examples of formal stakeholder forums that have been established to address these types of issues at the RTO level. It is certainly the case that in ISO-NE there are significantly

58 For example, in one instance, ISO-NE was coordinating a solution to a major transmission line issue caused by proposed DER projects across state lines with a local utility. Concurrently, another utility was attempting to find a solution to the same issue on the same transmission line across the state border. The second utility conducted two separate year-long transmission studies involving over 20 DER developers, each paying over a hundred thousand dollars in study fees, who were told the resulting upgrades to the transmission line would cost hundreds of millions of dollars, to be shared by only a small handful of projects. The developers brought the issue to the applicable state regulatory agency and soon after, ISO-NE realized that the first utility's solution could also solve the second utility's issue. The cost of the transmission line upgrades was dramatically reduced, but the DER projects all had to be restudied using the new solution, resulting in hundreds of thousands of dollars in additional fees and yet another year of delay just to determine if the proposed projects would be able to afford the combined transmission and distribution system upgrades. If ISO-NE had better visibility into what each utility was proposing from the beginning of the planning process and worked with all utilities concurrently to address impacts on both distribution and transmission systems, hundreds of megawatts of DERs could have been deployed much sooner and at far less cost.

better communication protocols in place than there were when these issues first started arising a few years ago, however, the region would still benefit from an RTO led forum on this topic. While it is not directly related to this issue, one successful regional forum that has been convened by ISO-NE to address other impacts from DERs is the Distributed Generation Forecast Working Group (DGFWG).

First established in 2013, the DGFWG was formed when ISO-NE first started to notice that DG deployed across the New England states was starting to materially impact its load forecasts. The DGFWG was created to help ISO-NE better understand what was currently deployed on the system, formulate more accurate load forecasts, and estimate the future growth of DG. Since its establishment it has brought together state agency representatives, utilities, and other stakeholders to develop accurate forecasts of the impact DG is having on the regional power grid and what that impact will likely look like in future years.

A forum to address transmission level issues related to DER deployment would have a very different mission, but the creation of the DGFWG is a good example of an RTO responding to a specific issue and taking a leading role in coordinating a top-down forum to address that issue. There is likely nothing that would prevent an RTO from convening a similar working group with the explicit purpose of coordinating and communicating on other regional grid issues arising from the interconnection of DERs.

B. Develop Multi-Jurisdictional Roadmaps

Some states have begun to address this lack of coordination between jurisdictions by convening collaborative stakeholder processes and issuing clear directives regarding communication protocols and procedures that distribution utilities must follow when transmission level issues are at play as part of a distribution level interconnection process. These help address the lack of coordination from the bottom up, but more could be done at the RTO and transmission level as well. For example, FERC and/or RTOs could establish similar protocols and procedures that RTOs and the transmission owners that they oversee must follow as well. This would ensure that all parties (DER developers, distribution companies, transmission owners, and RTOs) are held accountable and that there are clear processes in place that govern the interactions between each when impacts on the distribution system lead to impacts on the transmission system.

As noted above, there is no good example of a formal top-down approach that has been implemented in this area by FERC, an RTO, or a transmission operator. However, in the jurisdictions where transmission level studies have become an issue for DERs seeking to interconnect (e.g., Maine, Massachusetts, and Rhode Island), there have been some notable and productive steps taken by state regulators to address these challenges.

Case Study: Massachusetts Affected System Operator Study Guidance

On May 22, 2019, the DPU opened an investigation (D.P.U. 19-55) into the interconnection of distributed generation (and energy storage). Among the first topics explored was the process for affected system operator (ASO) studies (i.e., transmission level studies triggered by DERs).

Following a stakeholder process involving multiple technical conferences and rounds of public comment, on September 25, 2019, the DPU issued interim guidance related to ASO studies, which primarily governed the processes that distribution companies subject to its regulation must follow when communicating to interconnecting facilities about such studies. It also contained a number of directives regarding ongoing reporting requirements for the distribution companies relating to ASO studies that are being planned or are currently underway. The guidance was designed to address pressing issues and provide the DPU with more time to issue a final order following the receipt of comments.

Two days after the DPU issued this interim guidance, consensus edits to the state's model interconnection tariff were jointly submitted by interested parties on September 27, 2019. Additional comments and non-consensus edits were provided by parties separately during the following month.

On August 6, 2020, the DPU issued an order and an accompanying attachment that permanently adopted the majority of its interim guidance and made some additional revisions to the interconnection tariff in response to comments submitted by stakeholders.

While other issues persist with ASO studies, the work conducted by the DPU in this instance is a fine example of a regulatory agency utilizing its authority to address an issue of immediate concern by establishing clear protocols that must be followed by distribution companies when communicating with customers. Since the adoption of the interim guidance there have been major improvements in the flow of information from the electric distribution companies.

Case Study: Rhode Island Affected System Operator Study Guidance

On October 11, 2019, the RIPUC adopted the reporting requirements set forth by the MA DPU in its interim guidelines two weeks prior. On August 25, 2021, National Grid submitted revisions to its interconnection tariff based on the consensus recommendations of a collaborative effort between National Grid, the RI Office of Renewable Energy Resources (OER), and the Northeast Clean Energy Coalition. With respect to Affected System Operator (ASO) Studies, the modifications establish additional requirements on National Grid to increase transparency and information sharing. Specifically, when it becomes available, National Grid must communicate the plan for conducting the ASO Study, the responsibilities of each party, the scope of the ASO Study, the expected timeframe for completion, and the estimated cost of the ASO Study. Much of this work is modeled on what was completed in Massachusetts over the course of the two years prior.

RIPUC DG Interconnection Reporting Requirements Webpage

C. Clarify Federal v. State Jurisdiction Over Interconnection Applications

One issue that remains unresolved in the jurisdictions that have encountered it to date is the matter of when and how it is communicated to an applicant for interconnection whether the distribution line to which they wish to interconnect is FERC jurisdictional. Pursuant to the Open Access Transmission Tariff, when a DER connected to the distribution system participates in a FERC regulated wholesale market, the entire distribution feeder to which that DER is interconnected becomes FERC jurisdictional, which means that any DER that subsequently seeks to interconnect to the feeder must apply for interconnection using the FERC jurisdictional interconnection process applicable in that location.

This creates several challenges as a distribution company may not be fully apprised of whether a facility on a particular feeder is participating in a FERC regulated wholesale market. Accordingly, they may not be able to properly inform an interconnecting customer what the status of the feeder is. This has led to situations where it is unclear whether a customer should be submitting an interconnection application to the distribution company through a state jurisdictional interconnection process or through a FERC jurisdictional interconnection process. In some instances, customers have been informed that they must reapply for interconnection through the FERC jurisdictional process after their facility has been fully constructed and has nearly completed the entire state jurisdictional process.

This is clearly a completely untenable situation for project developers to be placed in and it is incumbent on utilities, RTOs, state regulators, and FERC to address this uncertainty by establishing clearer procedures and rules. State regulators could likely take action to hold distribution companies accountable for knowing whether their feeders are subject to state or federal jurisdiction.

That said, the most efficient solution to this issue may be for FERC to clarify that facilities connecting to distribution infrastructure that are participating in FERC regulated wholesale markets are not required to apply for interconnection through a FERC jurisdictional interconnection process. Notably, in its issuance of Order 2222 on September 17, 2020, FERC stated the following with respect to DERs participating in wholesale markets as part of an aggregation:

> *"we decline to exercise our jurisdiction over the interconnections of distributed energy resources to distribution facilities for the purpose of participating in RTO/ISO markets exclusively as part of a distributed energy resource aggregation. Thus, we will not require standard interconnection procedures and agreements or wholesale distribution tariffs for such interconnections."*[59]

Given that FERC has already waived jurisdiction over the interconnection of DERs that will be participating in wholesale market aggregations once Order 2222 is fully implemented (which could likely be the vast majority of DERs depending on how final rules are structured), it seems as though it would not be a far stretch for it to go one step further and waive jurisdiction over the interconnection of DERs participating in RTO/ISO markets generally. Should it take this step, it would immediately resolve these questions over interconnection jurisdiction and would remove uncertainty over which processes DERs seeking to interconnect should be using across the country.

This issue has primarily been experienced in the northeast to date, but it is likely that other jurisdictions will encounter it as well as DER penetration increases. For the time being, Massachusetts is one state that has been working to address "outstanding significant" concerns regarding the topic of state vs. federal jurisdiction. In March 2021, the DPU informed stakeholders that it planned to issue an order on the topic to clarify what items it could but given certain concerns that were subsequently raised by stakeholders to the DPU, it decided that it needed additional stakeholder discussion and has not yet issued an order as of the date of this publication.[60] At present, this topic remains largely unresolved and could significantly benefit from more clarity from FERC as state regulatory bodies have limited ability to make assertions regarding the process for an RTO and/or utility determining whether a distribution feeder is FERC jurisdictional.

59 Order 2222 at 74.

60 See DPU-19-55.

VI. Summary of DER Roadmap

Challenge	Recommendation	Leading Entity
1) Establish Clean DER Integration Objectives Through Legislative Action		
Lack of Comprehensive DER Legislation	Direct regulatory agencies to prioritize decarbonization	State legislators and policymakers
	Provide regulatory agencies with the financial resources they need to effectively administer and regulate DER programs	State legislators, legislative staff, energy and environmental advocates
	Clearly communicate the interconnection and grid planning needs of legislatively enabled programs	State legislators and policymakers
2) Expand Resources Available to State Regulators		
Insufficient DER Regulatory Resources	Increase resources: expand staff, establish technical and policy working groups, use third-party facilitators, and create an interconnection ombudsperson role.	Regulatory agencies, with partnership from other organizations (e.g. IREC, NRRI (NARUC), RAP, SEPA)
	Expand accessibility to stakeholder forums.	Regulatory Agencies, utilities, energy and environmental advocates
	Utilize federal resources.	State agencies, regulatory agencies, utilities, DOE, national labs
	Coordinate with national associations.	NASEO, NARUC
3) Realign Utility Incentive Frameworks		
Limited Utility Incentive Structure	Reform existing incentive frameworks, and direct utilities to facilitate DERs.	State legislators, regulatory agencies, regulatory staff, utilities
	Establish and/or expand regulatory enforcement measures.	
4) Establish Integrated Distribution and Transmission System Planning Processes		
Lack of Coordinated Systems Planning	Implement integrated distribution planning (IDP) processes	State legislators, regulatory agencies, regulatory staff
	Create intrastate and regional forums to encourage cooperation.	Regulatory staff, customers, additional stakeholders
5) Reform Cost Allocation Methodologies		
Inequitable Cost Allocation Methods that Impede Development	Implement Multi-Beneficiary Cost Sharing	Regulatory agencies, utilities
	Implement a market-based grid access fee	State regulatory agencies, utilities, stakeholders
6) Invest in Grid Modernization Technologies that Support DER Integration		

Lack of Transparent, Accurate, and Timely Data	Utilize advanced grid data management systems (DMS, SCADA) and tools	State legislatures, regulatory agencies
	Utilize Voltage and Volt-ampere Reactive Optimization (VVO)	Utilities
	Utility investment in a Distributed Energy Management System (DERMS)	Utilities
	Hosting capacity analyses and maps	Utilities, with feedback from industry stakeholders
7) Reduce Unnecessary Barriers to Interconnection		
Lack of Uniform Standards; Slow Pace of Integrating New Concepts	Establish an open, transparent interconnection queue process for applicants.	RTOs, State regulatory agencies, utilities
	Increase transparency of fee and equipment cost data	Utilities
	Apply best practices and transparency regarding technical standards	State regulatory agencies, staff, utilities, DER developers
	Enable dynamic curtailment and self-limitation via an active network and project management	Utilities, DER developers
	Allow interconnecting customers to self-build system upgrades	DER developers, customers, utilities
	Standardize application processes	Regulatory agencies, utilities, DOE or other federal agency
	Permit information sharing and mitigation review within studies	Regulatory agencies, utilities, DER developers
	Incorporate energy storage into interconnection rules	Regulatory agencies, utilities, DER developers
8) Improve Coordination with RTOs		
Lack of Coordination with Other Affected System Operators	Establish collaborative stakeholder forums	RTOs, transmission owners, EDCs, DER developers, state agencies
	Develop multi-jurisdictional roadmaps	RTOs, FERC
	Clarify federal vs. state jurisdiction over distribution-level interconnection applications	RTOs, FERC, state regulatory agencies, utilities

VII. Conclusion

The energy sector in the United States is actively undergoing a massive transformation. New technologies, changing regulatory frameworks, shifting customer demands and preferences, and the pressure to quickly decarbonize the economy is and will continue to lead to significant changes to our electric grid and the utilities that administer it. Among all of these changes, the most dramatically transformative of them all is the deployment and integration of DERs.

As discussed above, the introduction of DERs onto the electric grid represents an immense shift in the way power is generated and delivered to end use customers. If deployed thoughtfully and integrated into the electric grid in a way that optimizes their usage, they have enormous potential to provide significant benefits to all consumers in the form of reduced costs and emissions as well as improved reliability, resiliency, power quality, and efficiency. At the same time, the integration of DERs is also challenging from both a technical/engineering perspective as well as from a policy standpoint. This is because their deployment to the electric grid requires investment in new infrastructure and technologies by utilities and can often come into direct conflict with existing utility business models and financial interests.

While these challenges to effectively integrating DERs are real, they must be confronted head on as DERs continue to become more accessible to consumers, are proliferating at a rapid rate, and have the opportunity to provide significant value to consumers if integrated properly. As such, it is incumbent upon policymakers, regulators, utilities, and advocates to take proactive steps to address the challenges outlined in this paper. Though national and regional coordination will be required at some level, the vast majority of this policy and regulatory action will need to occur at the state level. Fortunately, states such as California, Hawaii, Massachusetts, New York, and others have been leading the way, creating ambitious clean energy targets and developing innovative policies to meet those goals.

This paper provides a comprehensive pathway for stakeholders to follow and cites numerous case studies that highlight the best practices and thought leaders in this space to date. That said, nowhere has figured out precisely how to best accomplish the objectives outlined in this paper to date and even jurisdictions that have been working hard on DER integration for many years have much work left to do.

When adopting regulatory, market, and technical reforms to modernize the electric grid and integrate new technologies and test new business models, it is critical that states take a holistic approach and examine the topic broadly. States that have made the most progress to date have established core principles and goals upfront before organizing their subsequent regulatory proceedings into more manageable subtopics. We urge policymakers, regulators, utilities, and advocates to follow the recommendations outlined in this paper, learning from other states while forging their own paths towards a decarbonized future in which DERs are fully integrated into the electric grid and markets.

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