

PENINSULA ADVANCED ENERGY COMMUNITY (PAEC)

TASK 4.2: FINAL BEST PRACTICES: INTERCONNECTION FOR LOCAL, COMMERCIAL- SCALE, RENEWABLE ENERGY PROJECTS

STREAMLINING THE INTERCONNECTION OF ADVANCED ENERGY SOLUTIONS TO THE GRID

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About the Clean Coalition

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise.

The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of distributed energy resources (DER) — such as local renewables, advanced inverters, demand response, and energy storage — and we establish market mechanisms that realize the full potential of integrating these solutions. The Clean Coalition also collaborates with utilities and municipalities to create near-term deployment opportunities that prove the technical and financial viability of local renewables and other DER.

Visit us online at www.clean-coalition.org.

Legal Disclaimer

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1. Introduction

a. Importance of streamlining interconnection

The Best Practices Final Report recommends reforms to federal and state interconnection procedures to meet the demands of a growing national marketplace for solar photovoltaic (PV) and other small renewable resources that interconnect to the electric grid. Updating federal and state interconnection processes can have a significant, positive impact on the efficiency and transparency with which renewable energy systems are interconnected nationwide, which in turn can have a significant impact on the cost of meeting state energy policy goals and objectives.

Interconnection processes serve two fundamental purposes: 1) they provide a transparent and efficient means to interconnect generators to the electric grid; and 2) they maintain the safety, reliability and power quality of the electric grid. Federal and state regulators are faced with the challenge of keeping interconnection procedures updated against a backdrop of evolving technology, new codes and standards, and considerably transformed market conditions. This report is intended to educate policymakers and stakeholders on beneficial reforms that will keep interconnection processes efficient and cost-effective while maintaining a safe and reliable electric grid.

Interconnection policies, which clarify the steps and responsibilities for interconnecting new generating facilities to the nation's electric grid, have a direct and substantial impact on the timing and cost of bringing new generating capacity online. An effective interconnection process contributes to lowering the cost of interconnection and, therefore, the overall cost of developing new capacity, increasing wholesale market competition, and encouraging investment in appropriate Distributed Energy Resources (DER) and associated distribution system infrastructure and cost savings.

For many developers, the interconnection process is one of the most time-consuming and costly aspects of developing a generating facility. Frequently, many developers claim that the process is opaque and consists largely of internal utility business practices such that implementation varies drastically from utility to utility. Moreover, this lack of transparency and certainty introduces significant development risk. Delays in the interconnection process slow development and may undermine access to valuable tax incentives and utility solicitations.

Utilities are responsible for maintaining the safety and reliability of the electric grid. From this perspective, any interconnection can raise the potential for safety, reliability, and service quality factors that may expose the utility to increased levels of risk. If there is any possibility for reliability or safety impacts, utilities will want to study those impacts to determine appropriate protective or mitigating measures.

Both parties require access to reliable information about the electric grid so they can better determine lower-cost, lower-impact opportunities to interconnect. They also

need certainty and transparency regarding the cost and timeline for processing interconnection studies and justification of proposed interconnection upgrades.

Regulators are seeking solutions that allow utilities to maintain the safety and reliability of the electric grid while providing developers a transparent, efficient, and cost-effective process that operates on reasonably predictable timeframes, and the challenge of keeping interconnection processes up to date against a backdrop of evolving technology, updates to relevant codes and standards, and changing market conditions.

i. Investor owned utilities are struggling to keep up with interconnection requests for small systems which provide energy to the utility or wholesale market

Even for the small residential facilities benefiting from retail Net Energy Metering (NEM) policies, interconnection timelines increased from 2014 to 2015, according to a survey of data for 62 utilities in 20 states that have a large number of residential solar customers.¹ For preconstruction timelines, the median utility wait time increased from 14 days in 2014 to 18 days in 2015, and for permission to operate (PTO) timelines, the median utility wait time increased from 28 days in 2014 to 45 days in 2015.

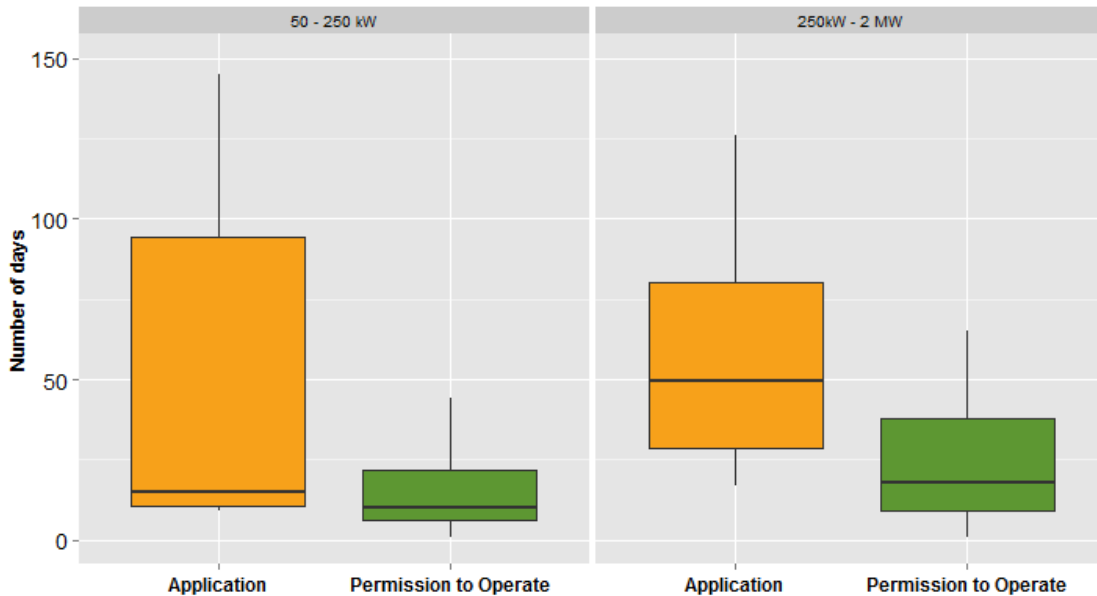
These figures increase with the size of individual installations, inhibiting realization of the benefits of scale. From the date a PV installer submits an interconnection application to the utility to the date the installer receives the utility's PTO, the median total number of days is 52 for U.S. residential projects (up to 10 kilowatts (kW)), and 62 total days for small commercial installations (10–50 kW).²

In the NREL study as shown in **Figure 1**, median application timeframes alone are 15 days for the commercial scale 50 to 250 kW sample, rising to 51 business days for the larger 250 kW to 2 MW sample. As in the residential samples, the range of values for application review and approval is larger than the range for PTO, indicating that, across all system sizes, there is a greater variance in application completion timeframes compared to PTO timeframes. This also indicates that projects fall into one of two categories: (a) projects that move through the process well below the typical regulated timeframes (10–15 business days), or (b) projects with significant delays.

¹ Chelsea Barnes, Justin Barnes, Blake Elder & Benjamin Inskeep, EQ Research, *Comparing Utility Interconnection Timelines for Small-Scale Solar PV*, 2nd Edition (Oct. 2016), available at <http://eq-research.com/wp-content/uploads/2016/10/EQ-Interconnection-Timelines-2016.pdf>.

² A State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States K. Ardani, C. Davidson, R. Margolis, and E. Nobler *National Renewable Energy Laboratory*. Technical Report NREL/TP-7A40-63556. January 2015

Figure 1: Days for application review and approval and PTO



In California, the study and approval process varies by project type. Residential projects are typically approved in less than 10 days under the NEM retail procedures. However wholesale projects require 1-5 months under Fast Track, 5-12 months if detailed studies are triggered, and 1-2 years if required to participate in the annual cluster study process. In practice, the Fast Track process is only effective for a subset of photovoltaic projects, and all others are subject to longer review, including storage facilities capable of exporting energy to the electric grid.

Once the interconnection requirements are established and agreed upon, completing any necessary field work and distribution system upgrades typically requires months of advanced scheduling, which cannot occur until after the interconnection agreement is completed, and is subject to seasonal availability and reprioritization, meaning that much more time is often required to connect a new generating facility to the electric grid than is required to develop the facility itself.

The Clean Coalition has reviewed California regulated investor owned utility wholesale interconnection queue progress reports and interviewed commercial participants to determine the timeframes associated with a typical 1 MW size installation, representing the typically most cost effective scale for wholesale development providing energy close to loads within the distribution system. These time frames extend from a minimum of six months to a maximum exceeding 2.25 years, with a typical expectation of 1.5 years, as

detailed in **Table 1** below, nearly twice the time required for an identical project under NEM tariffs.

Table 1: Project Development Timeline

WDG Rooftop 1 MW Fast Track Project Development (Project where ICA map indicates sufficient capacity)	Timeframe (business days)		
	Max	Minimum	Typical
PRELIMINARY WORK AND SITE CONTROL	180	60	120
Site Selection	2	1	1
Preliminary site evaluation and project screening	2	1	2
Preliminary layouts and performance models	2	1	2
Site control (Lease Option Agreement)	180	60	90
Pre-application reports	60	30	45
Other site research and selection	120	30	75
INTERCONNECTION INITIAL REVIEW	160	55	110
Prepare and submit interconnection application	120	30	75
Utility deems application complete	10	10	10
Initial review results (if pass, go to GIA cost estimate or GIA)	15	15	15
Developer requests initial review results meeting or proceeds to supplemental review	10	0	5
Initial review results meeting (if successfully identified, go to GIA cost estimate or GIA)	5	0	5
INTERCONNECTION SUPPLEMENTAL REVIEW	55	35	45
Decide to proceed to Supplemental Review	10	0	5
Supplemental review results (if pass, go to GIA cost estimate or GIA)	20	20	20
Developer requests supplemental review results meeting	15	0	5
Supplemental review results meeting (if successfully identified, go to GIA cost estimate or GIA)	5	0	5
Provide GIA cost estimate	15	15	15
POWER SALE CONTRACT	180	60	120
Lease negotiation	180	60	90
Site due diligence (structural, roof condition, soils, electrical/services, etc.)	50	20	30
Negotiate GC/EPC and engineering contracts	30	10	20
Final system engineering, design and integration; performance modeling	20	5	10
Permits	80	40	60
Financing pre-commitment			
Review power sales options	90	30	60
Obtain Power Purchase Agreement	90	30	60
GENERATOR INTERCONNECTION AGREEMENT (GIA)	95	17	50
Request GIA	15	1	5
Utility provides GIA	15	15	15
GIA negotiations and signatures (90 Calendar Day max time allowed)	65	1	30
GRID UPGRADES CONSTRUCTION**	250	0	190
Grid upgrade costs			
O&M costs (Cost of Ownership or COO)***			
Coordinate upgrade construction with utility, deed transfers			
PTO			
COD			
Totals (accounting for overlapping times)	830	197	575

These extended timeframes and uncertain outcomes in both cost and schedule add substantial risk and delay to bringing new renewable facilities online. This in turn reduces the opportunity for DER to be utilized effectively in both resource and infrastructure planning processes, and decreases the value of these resources to both ratepayers and providers.

ii. Failure rates for small (up to 1MW) WDG projects are too high and should be commensurate with similarly sized NEM projects

According to quarterly reports filed with the California Public Utilities Commission (CPUC), PG&E has received 209 Fast Track interconnection applications—not including Net Energy Metering (“NEM”) and non-export applications.³ This data is for 5 MW or less projects and does not include applications under other more detailed study processes, including Cluster Study, Detailed Study, and Independent Study Process.

Of the 209 Fast Track applications, 61 withdrew prior to either completing the application process or receiving the results of the Initial Review, and 138 projects failed Initial Review, and the top three most frequently failed screens are:

- 1) Screen J: Is the Generating Facility \leq 11kVA?
- 2) Screen I: Will power be exported across the PCC?
- 3) Screen M: 15% line section peak load check

After failing Initial Review, 96 applications requested Supplemental Review. At the time of reporting, 2 projects were still in Supplemental Review, and 51 projects passed. Of the withdrawals, 41 withdrew before Supplemental Review began, and 46 withdrew after Supplemental Review began. The top two most failed Supplemental Review screens are:

- 1) Screen N: Penetration Test
- 2) Screen P: Safety and Reliability Tests

In total, 37 projects signed a Generator Interconnection Agreement (“GIA”). A greater number of projects received GIAs, but this figure only reflects the Fast Track projects where the customer received and signed a GIA, in addition to not converting to a FERC jurisdictional interconnection agreement.

For the projects that did not complete Fast Track, there are many reasons why developers might have withdrawn applications. Upon review, developers might have discovered that a project is prohibitively expensive due to costly distribution grid upgrades. Other projects might not have obtained power purchase agreements in time to continue through the interconnection queue—where the projects would have been subject to deposits for

³ Cal. Pub. Utils. Comm’n, Quarterly IOU Interconnection Data Reports, <http://www.cpuc.ca.gov/General.aspx?id=4117> (last visited Feb. 23, 2017).

interconnection costs. Still other projects might have withdrawn because their applications were not completed correctly.

b. Background

In 2000, the National Renewable Energy Laboratory (NREL) published a study titled *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects*⁴. The NREL report was the first of its kind to address the problems associated with utility interconnection. The report stated that national leadership was needed to address interconnection of distributed generation.

That same year, California was among the first states to adopt comprehensive procedures for distribution system interconnections when the CPUC adopted Rule 21. Rule 21 implemented a screening process through which utilities could easily and objectively review an interconnection application to determine whether further studies or additional protective measures may be required. The initial review screens were designed primarily to ease the interconnection process for generators intended to serve onsite load. Rule 21 also included timelines to ensure the interconnection process would move forward in a timely manner.

Since California was among the first states to thoroughly address the interconnection process for a distribution system interconnection, the state's Rule 21 served as a basis for the development of technical standards, federal rules and other state procedures in subsequent years.

The federal government has provided some degree of guidance to states on interconnection policy. The FERC Order 2006, adopted in May 2005, includes three levels of review for DG systems up to 20 MW in capacity. Many states have adopted standards modeled on FERC's Small Generator Interconnection Standards (SGIP), which were issued by FERC in its Order 2006. As a result, there is greater consistency in employing a multi-level approach to system review depending on system capacity, generation type and location. Many states have also developed a standard agreement and concise application forms modeled on the FERC standard. However, despite a certain amount of unification brought about by FERC Order 2006, state interconnection standards remain fairly diverse in many respects, reflecting both the varied local influence of stakeholders, and the evolving needs of jurisdictions at the forefront of DER deployment.

In 2011, the CPUC opened a rulemaking to re-examine California's Rule 21 interconnection procedures in light of changed market conditions, stating:

“...when a generator seeks to primarily offset on-site load, interconnection under the existing Rule 21 generally occurs efficiently. In contrast, generators seeking to export a portion or all of their generation to the utility's distribution system lack a straightforward means of interconnection under the effective Rule 21. Exporting generators eligible to use Rule 21 as the interconnection tariff include those

⁴ Available at: <http://www.nrel.gov/docs/fy00osti/28053.pdf>

participating in a number of procurement programs administered by the Commission, including the renewable feed-in tariff, the efficient combined heat and power feed-in tariff and Qualifying Facilities up to 20 megawatts.”

Since that time, California has been actively updating and improving Rule 21 to address challenges in implementation, incorporate innovation and effective practices demonstrated in other local and state jurisdictions, and integrate new modeling capabilities and new technologies such as advanced inverters, energy storage, and DERMS and communications, and is actively exploring the opportunities of DER portfolios working in concert.

National technical standards, including IEEE 1547 and Underwriters Laboratories (UL) 1741, have been established and are amended or expanded as necessary to ensure that DER products and equipment, as well as interconnection practices, are safe. Without these national technical standards, equipment manufacturers and suppliers would be faced with developing separate devices and protection equipment to satisfy individual utility interconnection requirements. However, as technical standards can fail to keep up with the pace of technological advances and the needs of states to employ these capabilities, states may continue to lead the development of these standards, as California has demonstrated with regard to advanced inverter functionality.

Because jurisdiction can vary at the same location based on the authorized market participation of a facility, California has also worked to harmonize state jurisdictional Rule 21 and FERC jurisdictional wholesale distribution access tariffs in order to provide consistent interconnection rules and practices.

Many other states such as Hawaii, Massachusetts, and New Jersey have engaged in similar interconnection reform processes, with the Federal SGIP, California’s Rule 21, and Hawaii’s H14 generally serving as a starting point for stakeholder discussion, with active cross fertilization of refinements.

Contributing to understanding the issues to be addressed and best practices, NREL has continued to play a significant role in informing and coordinating state level development of rules and procedures, including the 2015 report *A State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States*.⁵ This study is a first step toward filling a significant gap in the literature on distributed PV interconnection costs and time requirements. Further research, for example via in-depth interviews with installers and utilities, could help to identify the exact sources of delays in various processes and inform the development of policies and practices that minimize the amount of time required of utilities and installers for PV deployment. Also, follow-on analysis informed by additional data sources—such as internal utility project tracking systems, regulatory databases and further data from PV installers—would enable the comparison of interconnection times more broadly.

⁵ Available electronically at <http://www.osti.gov/scitech>

2. Best practices for interconnecting small WDG

The guiding principles for these recommended interconnection practices emphasize predictability and efficiency in adapting to changing customer needs, market opportunities, and technical capabilities while utilizing existing capacity and maintaining safety and reliability of the electric grid. This is largely achieved through providing prospective applicants with simplified and clearly defined application and review processes appropriate to the nature of the proposed facility, as well as access to information that will help applicants assess site-specific constraints and develop appropriate project proposals before submitting an application. Continuing improvements should be pursued in both interconnection processes and technical solutions:

The use of common statewide and national standards, practices, procedures, and contracts is encouraged; where changes are appropriate to reflect local circumstances, these should be clearly identified to facilitate review.

Interconnection procedures should be designed to handle the expected scale of requests across all categories of distribution level interconnection, including residential and commercial, self-generation for non-exporting onsite use, intermittent export net metered credit, or exported for sale to the distribution system operator or host utility (Wholesale Distributed Generation or WDG)⁶. This includes a common application and associated qualification date for review and any necessary studies.

Clear and simple standards and procedures reduce errors and uncertainty, allowing applications to be handled consistently and without delay. Timely decisions avoid complications that may arise when a prior unresolved application is electrically related to a subsequent application.

Clearly delineated timelines define both the applicant's and Utility's responsibilities for timeliness and the significance of missing a deadline, while allowing for flexibility by mutual agreement or under extenuating circumstances.

Review processes should emphasize predictability, flexibility and objectivity, including screening and solution options to support:

1. Simplified review of appropriate projects
2. Default approval of conforming projects
3. Rapid resolution of most common issues
4. Identification of issues that will require further study if they cannot be addressed through supplemental review or simple project modification
5. Determination of specific technical study requirements where needed.

⁶ Note that interconnections for export of energy for sale beyond the host utility and into the Federally regulated wholesale market will, under the Interstate Commerce clause, be subject to FERC Wholesale Distribution Access Tariff rules in place of those of the local regulatory agency.

a. Information sharing processes

In order for the interconnection process to progress efficiently, states should establish adequate information sharing processes for applicants and utilities. Utilities should maintain current electric grid information in order to efficiently process interconnection requests and track the progress and outcomes of interconnection requests. Further, information sharing allows parties to address qualification screens, predict costs, reduce potential redesigning and restudy, and identify the least costly locations to interconnect early in the development process.

Applicants share information on their proposed projects with the utilities through interconnection applications, but not all states require utilities to share electric grid information with applicants. Allowing developers to access electric grid information prior to submitting an application saves both parties' resources and helps direct projects to areas of the electric grid where costly upgrades are not required.

The most useful information for prospective applicants includes:

- 1) Identification of preferred interconnection areas—defined as distribution substations and circuits in areas of high load with low distributed generation penetration where, based on initial utility screening, interconnection costs are minimal and expedited review procedures would likely be passed;
- 2) Known power quality or stability issues on the circuit;
- 3) Load data by month for the last twelve months, including day and night minimum loads with smaller increments if available;
- 4) Line and line segment available capacity, including capacity claimed by pending applications;
- 5) Line and line segment voltage and peak capacity and limiting conductor rating;
- 6) Distance between substation and line section terminus;
- 7) Known electrical dependencies at requested locations related to currently pending applications or plans;
- 8) Substation voltage and capacity;
- 9) Existing short circuit interrupting capacity;
- 10) Location, type, and rating of protective and regulating equipment on the circuit, including reclosers; and
- 11) Location of secondary networks.

States have developed two tools to better facilitate information sharing: pre-application reports and interconnection maps. Further, utility reporting ensures that regulators have current interconnection information.

i. Pre-Application Reports

For a relatively minimal fee, Pre-Application Reports allow applicants to determine what size and type of projects can interconnect to the existing electric grid infrastructure without modification. California was the first state to utilize this tool, and Massachusetts, North Carolina, and Ohio have all adopted their own versions. In California, the Pre-Application Report costs \$300 and contains the following information, if available:⁷

- 1) Total Capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.
- 2) Allocated Capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.
- 3) Queued Capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.
- 4) Available Capacity (MW) of substation/area bus or bank and circuit most likely to serve proposed site.
- 5) Substation nominal distribution voltage or transmission nominal voltage if applicable.
- 6) Nominal distribution circuit voltage at the proposed site.
- 7) Approximate circuit distance between the proposed site and the substation.
- 8) Relevant Line Section(s) peak load estimate, and minimum load data, when available.
- 9) Number of protective devices and number of voltage regulating devices between the proposed site and the substation/area.
- 10) Whether or not three-phase power is available at the site.
- 11) Limiting conductor rating from proposed Point of Interconnection to distribution substation.
- 12) Based on proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues.

California also recently approved an enhanced Pre-Application Report option that allows applicants to request a report better tailored to the specific context of the project.⁸ The Enhanced Pre-Application Report adds specific data with associated costs and timing to give applicants more complete cost information early in the interconnection process. Below are the two Enhanced Pre-Application Report options in California:⁹

⁷ See, e.g., Pac. Gas & Elec. Co., Elec. Rule No. 21 § E(1), available at https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.

⁸ Cal. Pub. Utils. Comm'n, Decision 16-06-052, *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 Company, and San Diego Gas & Electric Company*, Attachment B – Proposed Enhancements to Pre-Application Reports, Rulemaking 11-09-011 (June 23, 2016), available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K376/164376491.pdf>.

⁹ Pac. Gas & Elec. Co., PG&E's Pre-Application Report Request, https://www.pge.com/includes/docs/pdfs/mybusiness/save/solar/Pre_App.pdf (last visited Feb. 23, 2017).

Primary Service Package (\$225+\$100 if not requested concurrently with a Standard Pre-Application Report and 10 business days to complete): Nominal Distribution circuit voltage and wiring configuration:

- 1) Relevant line section(s) absolute minimum load, and minimum load during the 10 AM – 4 PM period (provided when SCADA data is available).
- 2) Existing upstream protection including:
 - a) Device type (Fuse Breaker, Recloser)
 - b) Device controller (device make/model ex: 50E/50T)
 - c) Phase settings [IEEE Curve, Lever, Min Trip (A), Inst Trip(A)]
 - d) Ground settings [IEEE Curve, Lever, Min Trip (A), Inst Trip(A)]
 - e) Rated continuous current
 - f) Short Circuit interrupting capability
 - g) Confirm if the device is capable of bi-directional operation
- 3) Provide the Available Fault Current at the proposed point of interconnection including any existing distributed generation fault contribution.

Behind The Meter Interconnection Package (\$800+\$100 if not requested concurrently with a Standard Pre-Application Report and 30 business days to complete):

- 1) Relevant line section(s) absolute minimum load, and minimum load during the 10 AM – 4 PM period (provided when SCADA data is available)
- 2) Transformer data:
 - a) Existing service transformer kVA rating
 - b) Primary Voltage and Secondary Voltage rating
 - c) Configuration on both Primary and Secondary Side (i.e., Delta, Wye, Grounded Wye, etc.)
 - d) Characteristic impedance (%Z)
 - e) Confirm if the transformer is serving only one customer or multiple customers
 - f) Provide the Available Fault Current on both the Primary and Secondary Side
- 3) Secondary Service Characteristics:
 - a) Conductor type (AL or CU) and size (AWG)
 - b) Conductor insulation type
 - c) Number of parallel runs
 - d) Confirm if the existing secondary service is 3 wire or four wire.
- 4) Primary Service Characteristics:
 - a) Conductor type (AL or CU) and size (AWG)
 - b) Conductor insulation type
 - c) Number of parallel runs
 - d) Confirm if the existing primary service is three wire or four wire.

ii. Interconnection maps

Interconnection hosting capacity maps are another essential information sharing tool. These maps allow applicants to easily identify areas on the electric grid where resources can

interconnect without costly electric grid upgrades. The information published supports conclusions regarding:

- What matching load limits exist at each line segment, circuit, and substation, including current and pending interconnections;
- What standard categories of upgrades would be triggered by exceeding these limits;
- What the appropriate costs would be for each level of upgrades required;
- Expected capacity increases related to planned system upgrades and new loads.

Utilities in California, Illinois, New York, Hawaii, and Delaware publish electric grid information on their websites for ease of access.¹⁰ California is currently leading improvements in mapping capabilities, with utilities and stakeholders working together to develop Integration Capacity Analysis maps.¹¹ When complete, these maps will provide more complete and up-to-date electric grid information to help to direct developers to electric grid locations with sufficient hosting capacity and, therefore, a lower probability of triggering expensive distribution system upgrades. The maps can also be refined to include information on electric grid locations where resources can provide system benefits.

iii. Utility Reporting

Requiring interconnection data reporting ensures projects are progressing through the queue as intended. Through utility reports, regulators can monitor the process and determine where and why any backlogs are occurring. Transparency also benefits prospective applicants who can obtain queue information to better determine the feasibility of potential projects.

In California, each utility publishes an interconnection queue on its website.¹² Further, the California Public Utilities Commission requires the utilities to report different types of interconnection data in quarterly reports that are available on the Commission's website.¹³ Additionally, the Hawaiian Electric Company publishes its Integrated Interconnection Queue

¹⁰ See, e.g., Pac. Gas & Elec. Co., Solar Photovoltaic and Renewable Auction Mechanism Program Map, https://www.pge.com/en_US/for-our-business-partners/energy-supply/solar-photovoltaic-and-renewable-auction-mechanism-program-map/solar-photovoltaic-and-renewable-auction-mechanism-program-map.page (last visited Feb. 23, 2017).

¹¹ Cal. Pub. Utils. Comm'n, *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, Rulemaking 14-08-013 et al. (May 2, 2016), available at <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF>.

¹² See, e.g., Pac. Gas & Elec. Co., Find additional resources for Wholesale Generation, https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/energy-transmission-and-storage/wholesale-generator-interconnection/additional-resources.page (last visited Feb. 22, 2017) (click "Download PG&E Wholesale Distribution Queue").

¹³ Cal. Pub. Utils. Comm'n, Quarterly IOU Interconnection Data Reports, <http://www.cpuc.ca.gov/General.aspx?id=4117> (last visited Feb. 22, 2017).

on its website.¹⁴ Finally, the Massachusetts Department of Energy Resources publishes monthly interconnection data from the utilities on its website.¹⁵

b. Transparent application and review processes

Clear and simple standards and procedures the reduce error and uncertainty. These procedures ensure utilities handle applications consistently and without delay. A number of state regulatory bodies require all utilities, including municipal utilities and electric cooperatives, to comply with the same interconnection requirements. This is essential to create a consistent and predictable process for applicants operating in different service territories.

States should design review processes that are predictable, flexible, and objective. The screening procedures should support:

- Simplified review of appropriate projects;
- Default approval of conforming projects;
- Different layers of review with an expedited timeline for conforming projects and a more detailed review for non-conforming projects to investigate potential modifications that would allow the project to interconnect within the predetermined limits;
- Identification of issues that require further study and cannot be addressed through an additional layer of review or a modification to the project;
- Rapid resolution of the most common issues; and
- Determination of specific technical study requirements where needed.

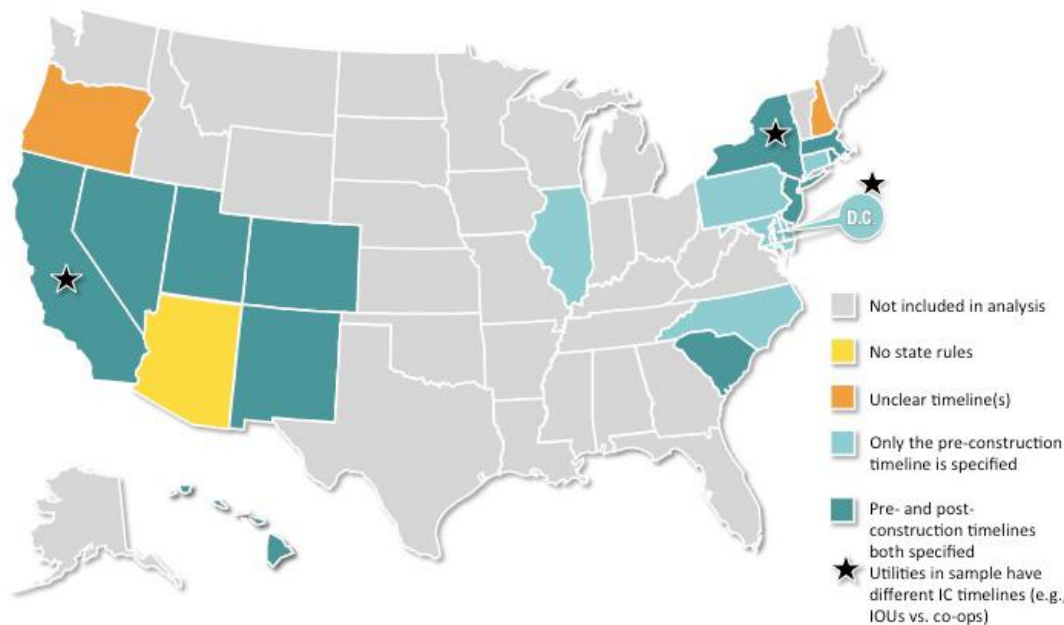
c. Predictable and Reasonable Timelines

States have found that one of the most reliable methods to prevent interconnection delays is through the adoption of timelines that provide reasonable deadlines for utilities and applicants. A timely decision-making process also avoids complications that may arise when a prior unresolved application is electrically related to a subsequent application. As seen in **Figure 2** below, a number of states have explicit interconnection approval timelines for systems 10 kW or less, but these same timelines should apply to all system sizes.

¹⁴ Hawaiian Elec. Co., Integrated Interconnection Queue, <https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/integrated-interconnection-queue> (last visited Feb. 22, 2017).

¹⁵ Mass. Dep't of Energy Res., Interconnection, <https://sites.google.com/site/massdgc/home/interconnection> (last visited Feb. 22, 2017).

Figure 2: State Rules Establishing Interconnection Approval Timelines for Systems <10kW



Source: *Comparing Utility Interconnection Timelines for Small-Scale Solar PV*, 2nd Edition

Penalties or incentives for failing to meet interconnection timelines ensure compliance with deadlines. Utilities remove applicants from the interconnection queue for failing to meet a deadline, while other tools are available to ensure utilities also comply with deadlines. Under its “timeline enforcement mechanism,” Massachusetts is the only state that currently subjects utilities to financial penalties for failing to meet interconnection timelines.¹⁶ New York, instead, provides performance-based incentives—known as Earning Adjustment Mechanisms (“EAMs”)—to utilities that improve interconnection processes.¹⁷ New York is developing the interconnection EAM based on surveys of DER providers of whether utilities complete interconnection requests in a timely and cost-effective manner. As part of this process New York is also considering a negative EAM for utilities that fail to meet established interconnection standards.

¹⁶ Mass. Dept. of Pub. Utils., *Order on a Timeline Enforcement Mechanism*, Appendix B, M.D.P.U. 11-75-F (July 31, 2014), available at <http://170.63.40.34/DPU/FileroomAPI/api/Attachments/Get/?path=11-75%2fOrder.pdf>.

¹⁷ N.Y. Pub. Serv. Comm’n, *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework* at 25, Case 14-M-0101 (May 19, 2016), available at <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD6EC8F0B-6141-4A82-A857-B79CF0A71BF0%7D>.

d. Queue management

Queue management is an issue both for states that have established updated interconnection processes and those that have not but need to address backlogs. Delays can be caused both by the utilities and by applicants, and queue management procedures need to take this into account. In electrically related areas, the position of an application can have dramatic effects on interconnection costs. Therefore, applications that have little chance of interconnecting in a timely and cost-effective manner should withdraw as soon as possible. Utilities utilize a combination of deadlines, milestones, fees, and deposits to manage interconnection processes and keep unviable projects from affecting queues.

California, Massachusetts, and North Carolina allow utilities to force applicants to progress through the interconnection process or withdraw.¹⁸ New York recently issued an Interconnection Management Plan in order to address a growing backlog of interconnection applications.¹⁹ The Plan requires projects to meet maturity thresholds or be removed from the queue. Projects must obtain property owner consent and site control and pay 25% of the interconnection fees in order to remain in the queue. Further, the utilities must publish a revised queue—updated monthly—after initially determining which projects will remain in the queue.

e. Dispute resolution procedures

Conflicts in the interconnection process will inevitably arise, and it is important to have procedures in place that are overseen by a neutral arbiter. Many developers do not resort to existing dispute resolution procedures because they can be time consuming, and developers want to maintain good relationships with utility staff. To address these issues, California recently passed a law to establish dispute resolution procedures for interconnection issues.²⁰ The law sets a goal of 60 days to resolve disputes, requires regulators to provide adequate staff to resolve disputes, and requires the appointment of a qualified electric engineer with interconnection expertise to provide advice to regulators.

f. Cost-certainty

Reliable price estimates for interconnection work allow developers to determine whether a project is financeable and viable. The utilities should provide cost data to applicants as early as possible in the process to ensure that the applicants and the utilities do not waste resources on

¹⁸ See, e.g., Pac. Gas & Elec. Co., Elec. Rule No. 21, available at https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.

¹⁹ N.Y. Pub. Serv. Comm'n, Case 16-E-0560, *Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings*, Attachment A: Queue Management Plan (Jan. 25, 2017), available at <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B22BEAB22-7F9F-45B8-89FD-0E8AD84692B4%7D>.

²⁰ Cal. Assembly Bill 2861 (Sept. 26, 2016), available at https://leginfo.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2861.

submitting and reviewing applications for unviable projects. Risks associated with costs that are not pre-established or standardized discourage development and increase project financing costs, leading to higher energy prices. Several methods exist to improve cost certainty, including the use of a fixed fee structure, per unit cost guides, and cost envelopes.

i. Fixed fee structure

California has a fixed-fee structure that applies to facilities interconnecting under the state's Net Energy Metering ("NEM") tariff.²¹ A fixed fee is beneficial because the utility can own the interconnection equipment without requiring developers to complete an ownership transfer process, which requires payments for associated taxes and operations and maintenance. To determine the fee, each utility averages costs for processing/administration, distribution engineering, metering installation/inspection and commissioning, and facility upgrades. The fees apply to all systems 1 MW and under, while systems over 1 MW must pay the fee plus any required electric grid upgrades.²²

ii. Per Unit Cost Guide

Many Independent System Operators and Regional Transmission Organizations currently publish cost tables containing common costs for interconnection equipment on the transmission grid. California recently extended this practice to the distribution grid. Utilities in the state must now publish Cost Guides listing the prices of typical interconnection facilities and equipment for the distribution grid.²³ The guides contain anticipated costs of procuring and installing a variety of project sizes, generation and storage resources, and locations deemed relevant to interconnection applicants. The guides will also contain forecasted costs for five years to allow applicants to better plan projects. The utilities must update the guides annually with input from applicants.

iii. Cost Envelope

Massachusetts pioneered the "Cost Envelope" model to ensure that interconnection applicants could rely upon utility cost estimates.²⁴ Under the approach, utilities provide applicants with a binding cost estimate, and the applicant pays any cost overage up to either 25%—if requested early in the review process—or 10%—if requested at the end of the review process. Utility shareholders then cover any costs above the threshold. Ratepayer advocates prefer this approach

²¹ Cal. Pub. Utils. Comm'n, Decision 16-01-044, *Decision Adopting Successor to Net Energy Metering Tariff* at 3, Rulemaking 14-07-002 (Jan. 28, 2016), available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf>.

²² *Id.* at 95–96.

²³ Cal. Pub. Utils. Comm'n, Decision 16-06-052, *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 Company, and San Diego Gas & Electric Company*, Attachment A – Cost Guide Implementation Principles, Rulemaking 11-09-011 (June 23, 2016), available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K376/164376491.pdf>.

²⁴ See Mass. Dept. of Pub. Utils., *Standards for Interconnection of Distributed Generation*, M.D.P.U. 1320 (Oct. 1, 2016), available at https://www9.nationalgridus.com/non_html/Interconnect_stds_MA.pdf.

because ratepayers are not responsible for cost overages and utilities therefore have an incentive to provide accurate estimates.

California's similar Cost Certainty Option offers a bankable guarantee that the final costs will be within 25% of the utility estimate by allowing a more detailed pre-contract estimation process that may require an additional 30–60 days.²⁵ This is further supported by new utility reporting to track and improve estimation processes and accuracy.

g. Cost-sharing for Electrically Related Projects

States have created processes to study groups of projects that are electrically related, and more recent innovations allow applicants to share electric grid upgrade costs among projects. New York's recently approved Cost Allocation Mechanism applies to substation 3V0 protection, substation transformer upgrades, and other substation-level shared upgrades.²⁶ To qualify, the first project to interconnect must pay for all electric grid upgrades, and then subsequent projects larger than 200 kW reimburse the first developer proportionally. This is intended to be an interim approach that stakeholders will refine over time. Massachusetts also has a rule requiring costs to be allocated across customers, but it is unclear if regulators enforce this rule.²⁷

h. Energy Storage

More utilities are receiving interconnection applications for energy storage as the resources become more cost effective. It is therefore important that utilities proactively plan for these applications. Energy storage can and should be treated the same as other generation technologies, but rules should be explicit that they also cover these resources. FERC's SGIP explicitly includes storage in its definition of "Small Generating Facility."²⁸ Further, California recently adopted interconnection rules for behind-the-meter, non-exporting

²⁵ Cal. Pub. Utils. Comm'n, Decision 16-06-052, *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 Company, and San Diego Gas & Electric Company* at 21–41, Rulemaking 11-09-011 (June 23, 2016), available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K376/164376491.pdf>.

²⁶ N.Y. Pub. Serv. Comm'n, Case 16-E-0560, *Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings* at 28–30 (Jan. 25, 2017), available at <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B22BEAB22-7F9F-45B8-89FD-0E8AD84692B4%7D>.

²⁷ Mass. Dep't Pub. Utils., Order 11-75-G (Revised Tariffs), Section 5.4 ("Should the Company combine the installation of System Modifications with additions to the Company's EPS to serve other Customers or Interconnecting Customers, the Company shall not include the costs of such separate or incremental facilities in the amounts billed to the Interconnecting Customer for the System Modifications required pursuant to this Interconnection Tariff. The Interconnecting Customer shall only pay for that portion of the interconnection costs resulting solely from the System Modifications required to allow for safe, reliable parallel operation of the Facility with the Company EPS.").

²⁸ Fed. Energy Reg. Comm'n, Small Generator Interconnection Agreement, Attachment 1—Glossary of Terms (July 21, 2016), available at <https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp>.

energy storage.²⁹ Utilities must now evaluate charging load the same as other customer load to determine cost allocation for load-related upgrades.

i. Automation and online interconnection portals

Automating interconnection processes is essential to reduce interconnection timelines. Automating processes requires greater upfront expenses but results in lower costs for both utilities and applicants. Utilities in California are currently working to automate both the Standard and Enhancement Pre-Application Reports as much as possible.³⁰ Further, online interconnection systems can automate many steps of application processing and tracking. Automated processes can also screen for electric grid reliability and penetration issues. Utilities in California have made notable progress with their online portals for NEM systems.³¹ This effort has also included creating online payment systems and permitting electronic signatures.

3. Model Interconnection Process for small WDG

- a. Pre-Review
 - i. Online Automation (Internal and External)
 - ii. Hosting Capacity Maps
- b. Fixed charge for eligible small WDG interconnection processes and avoiding developer requirements to pay for and then deed such upgrades
 - i. Eligibility requirements
 - ii. Proposed methodology for determining the fixed charge (modeled after the process used by NEM)
- c. Pre-Application Report for larger WDG projects
- d. Fast Track for larger WDG projects
 - i. Screens
 - ii. Initial Review
 - iii. Supplemental Review
- e. Detailed Study for larger WDG projects
- f. Additional Requirements for larger WDG projects
 - i. Interconnection Agreement

²⁹ Cal. Pub. Utils. Comm'n, Decision 16-06-052, *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 Company, and San Diego Gas & Electric Company* at 20, Rulemaking 11-09-011 (June 23, 2016), available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K376/164376491.pdf>.

³⁰ Cal. Pub. Utils. Comm'n, Decision 16-06-052, *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 Company, and San Diego Gas & Electric Company*, Attachment B – Proposed Enhancements to Pre-Application Reports, Rulemaking 11-09-011 (June 23, 2016), available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K376/164376491.pdf>.

³¹ See, e.g., Ken Parks & Bob Woerner, San Diego Gas & Elec. Co. and Pac. Gas & Elect. Co., *Innovation in the Interconnection Application Process*, presentation at Distributed Generation Interconnection Collaborative (Apr. 2, 2014), available at http://www.nrel.gov/tech_deployment/pdfs/2014-04-02_innovation-in-the-interconnection-application-process.pdf.

- ii. Insurance
- iii. Dispute Resolution
- iv. Utility Reporting
- v. Cost Certainty
 - 1. Unit Cost Guide
 - 2. Cost Envelope
 - 3. Cost Averaging
- vi. Miscellaneous

Overview of the Interconnection Process

Optional: Location Report – Prior to submitting an interconnection application, a Customer may request information regarding interconnection constraints at a specific location to assist in appropriate system proposals. If a written response is requested, it shall be provided within ten (10) business days. Fixed fees may apply at the discretion of the Utility in compensation for staff time.

Optional: Pre-submittal meeting/phone call - A Customer may request informal review or recommendations regarding a proposed interconnection application. Fixed or hourly fees may apply at the discretion of the Utility in compensation for staff time.

Step 1: Interconnection review begins when a Customer submits a completed Interconnection Application.³² The application shall not be presumed confidential except as specified otherwise in governing rules and regulations.

Step 2: Within ten (10) business days³³ of the receipt of an Interconnection Application and supporting material, or such other period as is mutually agreed upon in writing by the Utility and the Customer, the Utility shall review the Customer's Interconnection Application and supporting material and provide written notification of its general completeness, or alternatively, incompleteness. Upon determination of completeness, the Application shall be assigned the next sequential Interconnection Queue Position for determination of applicable priority in allocation of capacity and aggregate generation calculations. If an Interconnection Application is deemed incomplete, the Utility shall specify in a written notice the additional information that is required. The completeness determination cycle will be repeated as necessary until sufficient information is submitted by the Customer to enable the Utility to review the Interconnection Application.

Step 3: Within ten (10) business days of the date the Customer's Interconnection Application and supporting materials are deemed complete, the Utility will complete an Initial Technical Review of the Interconnection Application. The Initial Technical Review will result in the Utility providing either: (a) if all the Initial Technical Review Screens are passed, an executable Interconnection

³² Including 8760 hr estimated system output with applications for projects exceeding 25 kW assists evaluation.

³³ All parties are encouraged to expedite these processes in order to support efficient decision making and avoid cumulative delays; specified deadlines represent a maximum time frame, not a typical period. For example, staff may review applications and respond within 2 days of submittal in most cases. Online applications are strongly encouraged.

Agreement for the Customer's signature; or, (b) if one or more screens are not passed, notification that Supplemental Review will be required and the results, in writing, of all Initial Technical Review screens.

Optional Initial Review Results Meeting

Within five (5) Business Days of customer's request for an Initial Review results meeting, the Utility shall contact the customer and offer to convene a meeting at a mutually acceptable time to review the Initial Review screen analysis and related results to determine what modifications, if any, may permit the Generating Facility to be connected safely and reliably without Supplemental Review.

If modifications that obviate the need for Supplemental Review are identified, and the customer and Utility agree to such modifications, an Interconnection Agreement shall be provided within five (5) Business Days of the Initial Review results meeting if no Interconnection Facilities or Distribution Upgrades are required. If Interconnection Facilities or Distribution Upgrades are required, the Utility shall provide the customer with a binding cost determination of any Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Initial Review results meeting utilizing a standardized requirements and pricing worksheet.

If Applicant and Distribution Provider are unable to identify or agree to modifications that enable Applicant to pass Initial Review, Applicant shall notify Distribution Provider within five (5) Business Days of the Initial Review results meeting whether it would like to proceed with Supplemental Review or withdraw its Interconnection Request.

Step 4: If Supplemental Review is required, within fifteen (15) business days of notification by the Utility, the Customer shall notify the Utility, in writing, to proceed with the Supplemental Review, or the Customer shall agree to withdraw its Interconnection Application.

Step 5: Within fifteen (15) business days of notification by the Customer that it would like to move forward with Supplemental Review, the Utility shall complete the Supplemental Review. The Supplemental Review will determine what customer facility modifications, or distribution system upgrades, if any, may permit the Generating Facility to be connected safely and reliably without a detailed Interconnection Study (IS). This will result in the Utility providing either: (a) Simplified Interconnection (b) interconnection requirements beyond those for a Simplified Interconnection, and a binding cost determination to perform the interconnection upgrades identified by the Supplemental Review utilizing a standardized requirements and pricing worksheet³⁴³⁵³⁶, or (c) a determination that a detailed Interconnection Study (IS) is required, and

³⁴ Under principles of equal access:

- a. Use of existing capacity – a customer should not be required to bear the cost of having additional facilities installed if existing facilities are adequate and available; facilities will be made available on a 'first requested – first served' or 'first ready – first served' basis with consistent cost responsibility unless otherwise directed by law. Equipment otherwise required to provide service to load customers in the absence of a specific generating facility shall not be charged against that generating facility.
- b. Equal charges should be assessed for facilities required to interconnect customers either seeking load service or providing generation, irrespective of whether such charges are paid as a lump sum or apportioned to periodic (monthly) service charges or rolled into energy rates.

a binding cost determination and schedule for the completion of the IS, including an identification of the specific analyses and/or reviews that will be performed as part of the IS.

Step 6: If an IS is required, within thirty (30) business days of notification by the Utility, the Customer shall agree to pay for the IS, or the Customer shall withdraw its Interconnection Application. The Utility shall complete the IS within ninety (90) calendar days of the Customer's agreement to move forward with the IS and payment of the IS fee is received.

Step 7: Based on the results of the Initial Technical Review, or Supplemental Review (if needed), or IS (if needed), the Customer and Utility will work together to finalize the single-line diagram, relay list, trip scheme and settings, and three-line diagram, which is required in the circumstances set forth in the Interconnection Application. After finalization of the single-line diagram, relay list, trip scheme and settings, and three-line diagram (if required), the Customer will make any revisions deemed necessary to the Interconnection Application and resubmit the Interconnection Application to the Utility. Resubmission will not impact the Customer's interconnection queue position. The Customer must also complete a Facility Equipment List, which will identify equipment, space and/or data at the Generating Facility location that must be provided by the Customer for use in conjunction with the Utility's Interconnection Facilities. The Facility Equipment List will be included as Exhibit A to an Interconnection Agreement entered between the Utility and the Customer. If requested, the Utility will provide assistance to the Customer to complete the Facility Equipment List.

Step 8: Within fifteen (15) business days of the completion of all activities specified in Step 7 above, or within such other period as is mutually agreed upon in writing by the Utility and the Customer, the Utility will complete an identification of Interconnection Facilities that are necessary to complete the interconnection and that will be owned by the Utility. A list and description of the Utility's Interconnection Facilities will be included as Exhibit B to the Interconnection Agreement entered between the Utility and the Customer. The Utility and Customer shall mutually agree in writing to a schedule by which the Interconnection Facilities will be constructed and a determination of when the Customer's Generating Facility shall be connected to the Utility's Distribution System. The Interconnection Facilities are project-specific, and the time to complete the facilities will depend on the complexity of the facilities required. The Utility may require a periodic reservation deposit to maintain the IA³⁷, and may additionally establish a development deposit schedule if providing the required facilities. The Utility may require the Customer to maintain and show evidence of liability insurance coverage for the property scheduled for interconnection or be self-insured. The Customer Insurance Coverage will be included as Exhibit C to any Interconnection Agreement entered between the Utility and the Customer.

³⁵ The intent of intent of standardized pricing is to ensure equal treatment for similarly situated customers and binding cost determination to provide applicants with adequate cost certainty in order to make a decision.

³⁶ The Utility may, alternatively, elect to offer "time & materials" pricing that includes an estimated cost range and binding cap on customer charges. As noted elsewhere, the customer may elect to hire a third party installer approved by the Utility to perform the required work as identified by the review and defined by IA.

³⁷ To avoid a project that may not be developed from continuing to impact subsequent applications, an IA reservation maintenance deposit is recommended if the Utility is experiencing significant failure of projects to proceed to interconnect on schedule, or where scheduled interconnection is greater than 12 months and no development deposit is required within that period.

Step 9: Within five (5) business days of the completion of all activities specified in Step 8 above, the Utility will provide the Customer with an executable Interconnection Agreement, which must be executed prior to the interconnection and parallel operation of the Customer's Generating Facility. If requested by the Customer, the Interconnection Agreement may be signed by the Customer and a third party that is the owner and/or operator of the Generating Facility.

Step 10: The Utility will perform a pre-operation inspection within ten (10) business days of customer request or on other mutually agreed date following completion of facilities and prior to commencement of operation.

The Utility may, for good cause, modify the time limits to conduct the Initial Technical Review, Supplemental Review, or IS, and shall inform the Customer in writing of the need to modify the applicable time limit. The modified time limit shall be mutually agreed upon in writing between the Utility and the Customer. Final results of all technical screenings, Supplemental Review, and IS studies will be provided in writing to the Customer.

4. Recommendations not yet implemented

a. Standardized interconnection fee structure

In many jurisdictions, applicants are responsible for each project's actual interconnection costs, thereby preventing use of a fee that averages costs. Greater cost certainty could be provided through a fee structure that averages costs. **The fee should be based upon interconnection study and upgrade costs incurred by similarly situated projects.** A settlement account could also be created where savings would be deposited to cover potential cover cost overages. Applicants would benefit from this fee structure because it would provide pre-established interconnection pricing to eligible projects. Further, it should shorten the interconnection application and study phase because negotiation over assessment individual project cost responsibility would not be needed. Importantly, this process allows the utility to own the assets without having to complete an ownership transfer process, with the associated tax and operations and maintenance payments.

b. Continued automation of the interconnection approval process

Further steps should be taken to automate the review process for projects that conform to the operational profiles displayed in interconnection hosting capacity maps. A human engineer could review each Initial Review application to ensure quality control of the automated process. Automation could then also be investigated for Supplemental Review if the Deemed Complete and Initial Review procedures are successfully automated.

c. Combined interconnection applications for distributed energy resources aggregations

Utilities are beginning to deploy portfolios of distributed energy resources to meet identified electric grid needs, rather than defaulting to traditional electric grid upgrades. Utilities will need more visibility into how DER will behave when called upon in aggregate. Group study interconnection processes like the one in New York can address how to share fees in electrically related areas, but coordinated operation is not a consideration. Taking this approach one step further would allow aggregations of DER to apply for interconnection together, and the utility could investigate how the resources will respond when called upon in aggregate. Utilities could also modify interconnecting hosting capacity maps to reflect the operating profiles of different resources and investigate how portfolios of distributed energy resources affect hosting capacity.

d. Removal of project size

The project size limitation present in many states' interconnection tariffs is unnecessarily restrictive. The screening process described above ensures that projects can safely interconnect to the distribution grid, and the screens themselves will determine the size limit for any particular electric grid location. The Interstate Renewable Energy Council's ("IREC") Model Interconnection Procedures do not include a project size limitation and are applicable to all state-jurisdictional interconnection processes.³⁸ IREC recommends that the applicability of state or federal interconnection procedures should only depend on a jurisdictional inquiry.

e. Timelines for service planning, construction of upgrades, and meter installations

The benefits of clear and enforceable timelines during the interconnection application and study phase are well known. However, the same predictable processes do not exist for service planning, construction of upgrades, and meter installations. States should create enforceable timelines for these steps as well in order to avoid unnecessary delays after interconnection applications have been approved.

f. Eliminate confidentiality of interconnection information

Many utilities consider project-specific interconnection information to be confidential, but developers generally do not request confidential treatment of the information. Providing details on interconnection proposals as well as information about nearby developers can foster collaboration and reduce timelines and costs. Utilities, developers, and regulators should work together to determine the universe of interconnection information that should by default be

³⁸ Interstate Renewable Energy Council, Model Interconnection Procedures (2013), available at <http://www.irecusa.org/publications/model-interconnection-procedures/>.

deemed not confidential—unless the applicant opts out. Information would include constraints discovered through the study process, as well as the types of upgrades and costs associated with them.

g. Allow for competition in utility upgrades

Allowing interconnection applicants to hire qualified third-party providers to perform required upgrades is subject to utility discretion in many jurisdictions. Utilities, developers, and regulators should work together to identify and pre-approve contractors to perform interconnection work. This effort would increase competition, transparency, and efficiency.

h. Energy storage

Interconnecting energy storage can pose unique challenges and opportunities during the application and review process. Although storage resources may be capable of charging and discharging at certain rates, software constraints can be used to limit the resources' performance. Performance can also be limited by the time of day to ensure that the resources do not trigger electric grid upgrades. During the interconnection process for energy storage, parties should identify operational constraints to ensure that no costly electric grid upgrades would be required to interconnect the resources. IREC has published recommendations regarding the interconnection of energy storage.³⁹

i. Technical specifications

States should prevent utilities from requiring external disconnect switches for smaller, inverter-based systems.

j. Insurance

States should prevent utilities from requiring customers to purchase additional liability insurance beyond the coverage obtained under a typical insurance policy. States should also prevent utilities from requiring customers to add the utility as an additional insured entity.

5. Next Steps

Interconnection practices will need to continue to evolve in response to observed and predicted increasing deployment of DER, the introduction of new DER technologies, and new tools to process them. At the same time, DER functions and communications are enabling both delivery of services to the full range of markets to meet system wide, local, and individual customer needs. Distributed Energy Resource Management Systems

³⁹ Interstate Renewable Energy Council, *Deploying Distributed Energy Storage: Near-Term Regulatory Considerations to Maximize Benefits* at 31–33 (Feb. 2015), available at <http://www.irecusa.org/wp-content/uploads/2015/03/Deploying-Distributed-Energy-Storage-2-27-15-IREC-FINAL-Secure-1-1.pdf>.

(DERMS) and communications are both enabling and driving the distribution system into an active role in overall grid management; offer increased flexibility, resilience, reliability, and a much higher degree of resource optimization. Interconnection modeling and policies need to keep up with these opportunities in order to leverage the full potential benefits and avoid creating artificial barriers to both deployment and operation of these essential resources.