EXHIBIT 1

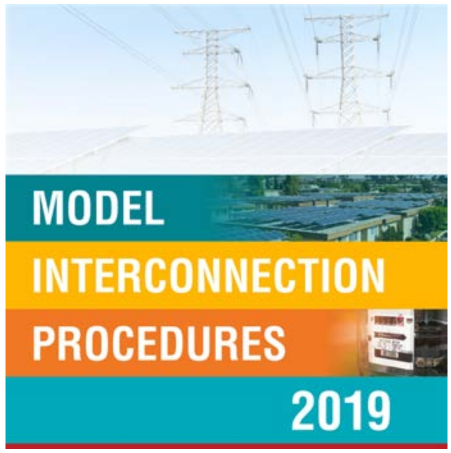
MODEL

INTERCONNECTION

PROCEDURES

2019

IREC



Interstate Renewable Energy Council

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About IREC

IREC builds the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy, and the planet. Our vision is a 100% clean energy future that is reliable, resilient, and equitable. IREC is an independent, not-for-profit 501(c)(3) organization that relies on the generosity of donors, sponsors, and public and private program funders to support our work.

INTRODUCTION

Initially developed in 2005 and updated in 2009 and 2013, *IREC's Model Interconnection Procedures, 2019 Edition* (2019 Model Procedures) synthesize and reflect the evolving best practices for safe and reliable interconnections of distributed energy resources (DERs)[1] on the electricity grid. For nearly 15 years, this publicly available, complimentary resource has helped guide and inform state utility regulators, energy industry professionals, utilities, policymakers, and other energy DER stakeholders as they develop and/or refine the rules for grid access. The goal of these Model Procedures is to streamline the process for safe and reliable interconnection for all DER customers, while also helping states and utilities save time and resources as they address interconnection issues.

These Model Procedures are informed by IREC's active intervention in dozens of state interconnection rulemakings over the years and participation in the Federal Energy Regulatory Commission (FERC) process to develop and update the Small Generator Interconnection Procedures (SGIP). In addition, IREC's consultation and coordination with DER developers, trade associations, utilities, manufacturers, national laboratories, consumer advocates, regulators, and other energy stakeholders informs our evolving understanding of interconnection issues and emerging best practices.

The 2019 Model Procedures reflect the latest evolutions in processes, practices and technologies that can facilitate higher penetrations of DERs on the grid, while still maintaining grid safety and reliability. The components of the procedures are intended to ensure a more efficient and cost-effective project development process, which saves money and time for consumers, developers and utilities alike. Among other changes, the 2019 Model Procedures include the following important updates:

- ***Interconnection of Energy Storage Systems:*** The procedures establish an initial framework for review of energy storage systems seeking to connect to the distribution grid. Although this is an evolving space, the guidance provided herein is intended to begin to address the uniquely flexible and controllable nature of energy storage.

- ***Requirements for Publishing a Public Queue and Reporting:*** New requirements have been added to ensure key data is publicly available, so all stakeholders have fair access to information about how the interconnection process is proceeding to inform decision-making.

- ***Updated Dispute Resolution Process:*** These new provisions include the creation of an interconnection ombudsperson role to provide for a neutral third party to help resolve and mitigate interconnection disputes more efficiently. A fair and efficient dispute resolution process can help address interconnection challenges, while also avoiding the need for more time-intensive complaints before the utility commissions.

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[1] The term Distributed Energy Resources, or DERs, refers to resources located on the distribution system (in front of or behind the customer meter).

- ***Clarification to the Material Modifications Provisions:*** These changes clarify what level of change requires a resubmittal of the interconnection application, for both existing interconnected projects and projects in the queue.

IREC's 2019 Model Procedures provide guidance and best practices on the following important issues and related questions impacting the interconnection of DERs to the grid. Ideally, the questions within each category should be clearly addressed in statewide interconnection procedures to clarify the process for all involved stakeholders.

APPLICABILITY & ELIGIBILITY

1. Does the state have interconnection standards that apply uniformly to all utilities within the state's jurisdiction?
2. Are the interconnection standards applicable to all projects or are there size or design limitations that may prevent state jurisdictional projects from having a clear path to interconnection?
3. What DERs are covered by the interconnection standards?
4. Is energy storage explicitly addressed, defined, and given a clear path to proceed through the interconnection review process?

SYSTEM SIZE & REVIEW PROCESS

5. What are the size limits for the different levels of review?
6. Is there an option to have expedited review process for small, inverter-based systems unlikely to trigger adverse system impacts? (e.g., under 25 kW)
7. Is there an option for a Fast Track review process for larger DERs (e.g., up to 5 MW) that utilizes a set of technical screens to determine whether projects are unlikely to require system upgrades and/or negatively impact the safety and reliability of the grid?
8. What technical screens are applied for the Fast Track review process?
9. Is there a transparent Supplemental Review Process for interconnection applications that fail the Fast Track screens?

TIMELINES

10. Are both the utility and the interconnection customer meeting established timelines?
11. What methods, approaches and tools are in place to improve the timeliness of the interconnection process (e.g., electronic application submittal, tracking and signatures)?
12. Is there an explicit process to clear projects from the interconnection queue if they do not progress?
13. Are there clear timelines for construction of upgrades or meter installs?

DISPUTE RESOLUTION

14. Is there a clear, efficient and fair dispute resolution process?

INFORMATION SHARING & TRANSPARENCY

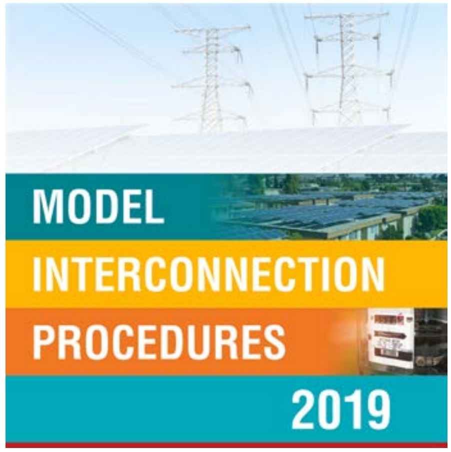
15. Is there a Pre-Application report that allows DER customers to obtain (for a reasonable fee) basic information about their proposed point of interconnection *prior* to submitting a full interconnection application?
16. Is there a transparent reporting process and publication of the interconnection queue to allow customers and regulators to see how projects in the queue are progressing?

Beyond the issues addressed in IREC's Model Procedures, there are a number of interconnection-related questions that states and utilities will need to address as a result of the adoption of *IEEE Standard 1547™-2018 for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces* ("IEEE Std 1547™-2018" or the "Standard"). This voluntary, nationally applicable Standard by the Institute of Electrical and Electronics Engineers will transform how DERs interact with and function on the electric distribution system. More specifically, the Standard requires DERs to be capable of providing specific grid support functionalities relating to voltage, frequency, communications and controls. Once widely utilized, these functionalities will enable higher penetration of DERs on the grid, while maintaining grid safety and reliability and providing new grid and consumer benefits.

Any current state rules and utility interconnection procedures that are based on IEEE Std 1547™-2003 will need to be updated to reflect these recent revisions. Clearly defining DER settings in statewide interconnection rules will help increase efficiency, minimize confusion, and reduce costs. States or utilities which have not yet adopted interconnection rules could begin the process today with IEEE Std 1547™-2018 in mind, to avoid having to amend their rules again later (which could be inefficient and resource intensive for all involved stakeholders). IREC's

Making the Grid Smarter: Primer on Adopting the New IEEE Std 1547™-2018 for Distributed Energy Resources provides a helpful summary of these issues and the corresponding policy considerations for states, utilities and other stakeholders. The primer is available along with other related IREC resources at www.irecusa.org.

Lastly, since IREC's Model Procedures were last updated in 2013, the market for energy storage has evolved significantly, which introduces new considerations into the interconnection process. For example, energy storage systems are controllable in a way not typically seen with distributed generation. In addition, many energy storage systems can be designed with the capability to limit or prevent export onto the grid. In some cases, an inverter-based power control system may have limited amounts of inadvertent export while the system responds to changes in load fluctuation. As a result of these unique characteristics, best practices for how best to analyze the grid impacts of energy storage are still emerging. These Model Procedures recognize these concepts and create an initial framework for reviewing energy storage and verifying energy storage system capabilities. However, the procedures do not resolve the question of how projects that inadvertently export should be evaluated in the screening process. IREC anticipates that the interconnection of energy storage will rapidly evolve in the coming years and looks forward to providing further updates as best practices emerge.



M O D E L I N T E R C O N N E C T I O N P R O C E D U R E S

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ATTACHMENTS

I. OVERVIEW

A. Scope

These Interconnection Procedures are applicable to all state-jurisdictional interconnections of Generating Facilities, including Energy Storage Devices.[1]

B. Order of Review

1. Optional Pre-Application Report: Potential applicants may request this optional report in order to get information about system conditions at their proposed Point of Interconnection without submitting a full interconnection Application.

2. Interconnection Review: There are four interconnection review paths, Levels 1 through 4, with options to undertake Supplemental Review and/or an Applicant Options Meeting prior to entering Level 4. The Utility will process the Applications in the order of their queue position as established by Section I.C.3 unless the Application is part of a group study pursuant to Section I.C.5.

   The four interconnection review paths are:

   a. Level 1 - For Certified inverter-based Generating Facilities that have a Nameplate Rating of 25 kilowatts (kW)[2] or less.

   b. Level 2 - For Generating Facilities that have a Nameplate Rating of up to 5 megawatts (MW), depending on line capacity and distance from substation, as detailed in the table in Section III.B.2.a.

   c. Level 3 - For Generating Facilities up to 10 MW that do not export power to the Utility (other than Inadvertent Export).

   d. Level 4 - For all Generating Facilities that do not qualify for Level 1, 2 or 3.

[1] Depending on state law, individual utility procedures may govern interconnections, particularly for municipal and cooperative utilities and public utility districts. These model Interconnection Procedures may be modified to apply to a particular utility. State or utility procedures do not apply when the U.S. Federal Energy Regulatory Commission (FERC) has jurisdiction over the interconnection, as is the case for many transmission interconnections, and on rare occasions, for distribution interconnections.

[2] Throughout these Interconnection Procedures, all rated capacity figures are measured in alternating current (AC).

C. Application Submission and Processing

1. Submission: The Applicant shall submit the Application (in either Attachment 3 or Attachment 4) to the Utility along with the applicable processing fee or deposit. No additional fees for processing of the Application shall be required unless specified in these Interconnection Procedures.

2. Completeness Review: The Utility shall record the date and time of the Application's receipt. The Utility shall notify the Applicant within three (3) Business Days that the Application has been received. Within ten (10) Business Days of receipt, the Utility shall notify the Applicant whether the Application is complete. If the Application is incomplete, the Utility shall provide the Applicant with a list of all information that the Applicant must provide to complete the Application. The Applicant must provide the requested information within ten (10) Business Days, or the Application will be deemed withdrawn.

3. The Queue: The Utility shall assign the Application a queue position based on when it is deemed complete under Section I.C.2. The Utility shall maintain a single queue, which may be sortable by geographic region (e.g., feeder or substation).[3] The queue shall contain all of the information listed in Attachment 8. The queue shall be publicly available on the Utility's website and shall be updated at least monthly.

4. Modifications to Application or to an Existing Generating Facility:

   a. At any time after an Application is deemed complete, including after the receipt of Fast Track, Supplemental Review, System Impact Study, and/or Facilities Study results, the Applicant or the Utility may identify modifications to the planned Generating Facility that may improve the costs and benefits (including reliability) of the Generating Facility, and/or the ability of the Utility to accommodate the interconnection. An existing Generating Facility may also propose such modifications. The

[3] Alternately, some states allow the maintenance of a separate queue for small projects proceeding under expedited review procedures such as the Level 1 review process. These projects are typically able to move ahead rapidly without the need for upgrades that impact other project and thus it is feasible to create a separate queue for these projects. In any case, the queue should be published in a manner that protects customer confidentiality. Also, if there is a delay in reviewing the completeness of applications, they shall be reviewed in the order received so that queue position is not undermined.

Applicant shall submit to the Utility, in writing, all proposed modifications to any information provided in the Application or Interconnection Agreement for existing Generating Facilities. The Utility may not unilaterally modify the Application.

b. Within ten (10) Business Days of receipt of a proposed modification, the Utility shall notify the Applicant whether a proposed modification to either an Application or an existing Generating Facility constitutes a Material Modification.

i. If the proposed modification is determined to be a Material Modification, then the Utility shall notify the Applicant in writing that the Applicant may: 1) withdraw the proposed modification; or 2) proceed with a new Application for such modification. The Applicant shall provide its determination in writing to the Utility within ten (10) Business Days after being provided the Material Modification determination results. If the Applicant does not provide its determination, the proposed modification shall be deemed withdrawn.

ii. If the proposed modification is determined not to be a Material Modification, then the Utility shall notify the Applicant in writing that the modification has been accepted and that the Applicant shall retain its eligibility for interconnection, including its place in the interconnection queue. Existing generating facilities may make the modification without requiring a new Application.

c. Any dispute as to the Utility's determination that a modification constitutes a Material Modification shall proceed in accordance with the dispute resolution provisions in Section IV.C of these procedures.

d. Any modification to machine data, equipment configuration, or to the interconnection site of the Generating Facility not agreed to in writing by the Utility and the Applicant may be deemed a withdrawal of the Application and may require submission of a new Application, unless proper notification of each Party by the other as described in Sections I.C.4.a and I.C.4.b. The terms of the

Interconnection Agreement apply for existing Generating Facilities.

5. Group Study: In some instances, typically where multiple Generating Facilities are electrically interrelated, studying them jointly in a group study process could increase cost and time efficiencies. If the Utility and the Applicant mutually agree, the Application may be studied in a group with other applications.[4]

6. Continued Review: If an Application is denied approval for interconnection under one level, but the Applicant decides to continue with review under another level within ten (10) Business Days of receipt of that denial, the Applicant shall retain its original queue position.

D. Applicable Standards

Unless waived by the Utility, a Generating Facility must comply with the standards identified in Attachment 2, as applicable.

II. PRE-APPLICATION REPORT[5]

A. Pre-Application Report Request

1. A Pre-Application Report Request shall include:

   a. Contact information (name, address, phone number, and email address).

[4] In markets with substantial interconnection activity it can be difficult for utilities to complete studies in a timely manner where there are many projects in the queue. Some states have created group or cluster study processes to try to move the study process faster. Group studies do create additional complexities, however, and no best practice has emerged on how to best handle them. It does make sense to allow them where a natural group of projects emerge (particularly where one developer is the proponent for multiple projects) and there can be a group study timeline and cost allocation worked out on a mutually agreeable basis.

[5] In addition to Pre-Application Reports, some utilities are now publishing publicly available maps of their systems, which provide basic information such as line voltage and capacity at specific points on the systems, or even offer actual calculated hosting capacity for each node. Adoption of mapping tools enable customers to get information without requiring utility staff time and can reduce the number of requests for Pre-Application Reports. California's Rule 21 also provides for an Enhanced Pre-Application Report. For an additional fee, an applicant can request additional packages of information from the utility, including information about minimum load, existing upstream protection devices, available fault current at the proposed Point of Interconnection, transformer data, and primary and secondary services characteristics. These can help applicants design projects more correctly from the start with fewer surprises later in the process.

b. A proposed Point of Interconnection. The proposed Point of Interconnection shall be defined by latitude and longitude, site map, street address, utility equipment number (e.g., pole number), meter number, account number, or some combination of the above sufficient to clearly identify the location of the Point of Interconnection.

c. Generating Facility type (e.g., solar, wind, combined heat and power, storage, solar plus storage, etc.).

d. Nameplate Rating and Generating Capacity (if different).

e. Single- or three-phase configuration.

f. Whether generator is stand-alone or will service on-site load.

g. Whether new service is requested.

h. $300 non-refundable processing fee.

2. In requesting a Pre-Application Report, a potential Applicant understands that:

a. The existence of "available capacity" in no way implies that an interconnection up to this level may be completed without impacts because there are many variables studied as part of the interconnection review process.

b. The distribution system is dynamic and subject to change.

c. Data provided in the Pre-Application Report may become outdated and not useful at the time of submission of the complete Application.

B. Pre-Application Report

1. Within ten (10) Business Days of receipt of a completed Pre-Application Report Request, the Utility shall provide a Pre-Application Report. The Pre-Application Report shall include the following information, if available:

a. Total capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.

b. Aggregate existing Generating Capacity (MW) interconnected to the substation/area bus or bank and circuit likely to serve proposed site.

c. Aggregate queued Generating Capacity (MW) proposing to interconnect to the substation/area bus or bank and circuit likely to serve proposed site.

d. Available capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site. Available capacity is the total capacity less the sum of existing and queued Generating Capacity, accounting for all load served by existing and queued generators. Note: Generators may remove available capacity in excess of their Generating Capacity if they serve on-site load and utilize export controls which limit the their Generating Capacity to less than their nameplate rating.

e. Whether the proposed Generating Facility is located on an area, spot or radial network.

f. Substation nominal distribution voltage or transmission nominal voltage if applicable.

g. Nominal distribution circuit voltage at the proposed site.

h. Approximate circuit distance between the proposed site and the substation.

i. Relevant Line Section(s) and substation actual or estimated peak load and minimum load data, when available.

j. Number and rating of protective devices and number and type of voltage regulating devices between the proposed site and the substation/area.

k. Whether or not three-phase power is available at the site and/or distance from three-phase service.

l. Limiting conductor rating from proposed Point of Interconnection to distribution substation.

m. 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 on the circuit, capacity constraints, or secondary networks.

n. Any other information the Utility deems relevant to the Applicant.

2. The Pre-Application Report need only include pre-existing data. A Pre-Application Report request does not obligate the Utility to conduct a study or other analysis of the proposed project in the event that data is not available. If the Utility cannot complete all or some of a Pre-Application Report due to lack of available data, the Utility will provide the potential Applicant with a Pre-Application Report that includes the information that is available and identify the information that is unavailable.

3. Notwithstanding any of the provisions of this Section, the Utility shall, in good faith, provide Pre-Application Report data that represents the best available information at the time of reporting.

III. INTERCONNECTION REVIEW

A. Level 1: Screening Criteria and Process for Certified Inverter-Based Generating Facilities Not Greater than 25 kW

1. Application: An Applicant must submit a Level 1 Application, pursuant to Section I.C.1, using the standard form provided in Attachment 3 to these Interconnection Procedures, which may be sent electronically to a recipient designated by the Utility. An Applicant executes the standard Interconnection Agreement for Level 1 by submitting a Level 1 Application. A Utility may elect to charge a standard Application fee of up to $100 for Level 1 review.[6]

2. Applicable Screens:

   a. Facility Size: The Generating Facility has a Nameplate Rating not greater than 25 kW and is using a UL 1741 Certified inverter.

   b. For interconnection of a Generating Facility to a radial distribution circuit, the Generating Facility's Generating Capacity[7] aggregated

[6] Most states apply a Level 1 Application fee in the $100 to $200 range, though a number of states have chosen to waive the fee for net-metered facilities. In general, the appropriate fee should ensure that the Utility is compensated, on average, for a conducting reasonably efficient process. This can be achieved by requiring a utility to provide data regarding its actual costs for processing Level 1 applications and how many Level 1 applications it processes. This same approach should be used for setting any fee in these Interconnection Procedures.

[7] Currently there is no best practice for how Screen 2.b (Section III.A.2.b) should address the potential for Inadvertent Export from Generating Facilities incorporating the methods in Section IV.E.5 or IV.E.6 to limit their Generating Capacity. Whether the Generating Capacity, as proposed here, or Nameplate Rating is more appropriate for study under Screen 2.b (Section III.A.2.b) should be addressed as part of individual states' review and update of their interconnection procedures.

with all other generation capable of exporting energy on a Line Section will not exceed 15 percent of the Line Section's[8] annual peak load as most recently measured at the substation or calculated for the Line Section.

c. If the Generating Facility is to be interconnected on a single-phase shared secondary, then the aggregate generation capacity on the shared secondary, including the Generating Facility's Generating Capacity, will not exceed 65 percent of the transformer nameplate power rating.

d. If the Generating Facility is single-phase and is to be interconnected on a transformer center tap neutral of a 240-volt service, its addition will not create an imbalance between the two sides of the 240-volt service of more than 20 percent of the nameplate rating of the service transformer.

e. For interconnection of a Generating Facility within a Spot Network or Area Network, the aggregate Nameplate Rating including the Generating Facility's Nameplate Rating may not exceed 50 percent of the Spot Network or Area Network's anticipated minimum load. If solar energy Generating Facilities are used exclusively, only the anticipated daytime minimum load shall be considered. The Utility may select any of the following methods to determine anticipated minimum load:

   i. the Spot Network or Area Network's measured minimum load in the previous year, if available;

   ii. five percent of the Spot Network or Area Network's maximum load in the previous year;

   iii. the Applicant's good faith estimate, if provided; or

   iv. the Utility's good faith estimate if provided in writing to the Applicant along with the reasons why the Utility

[8] Clarification of the relevant Line Section is sometimes necessary. If the point of common coupling is downstream of a line recloser, include those medium voltage (MV) Line Sections from the recloser to the end of the feeder. If the 15 percent criterion is passed for aggregate distributed generation and peak load at first upstream recloser, then the screen is passed. If the point of common coupling is upstream of all line reclosers (or none exist), include aggregate distributed generation relative to peak load of the feeder measured at the substation. If the 15 percent criterion is passed for the aggregate distributed generation and peak load for the whole feeder, then the screen is passed. A fuse must be manually replaced and is therefore not considered an automatic sectionalizing device.

considered the other methods to estimate minimum load inadequate.

3. Time to process screens: Within seven (7) Business Days after the Utility notifies the Applicant that the Application is complete, the Utility shall notify the Applicant whether the Generating Facility meets all of the applicable Level 1 screens.

4. Screens failure: Despite the failure of one or more screens, the Utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability. If the Utility cannot determine that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Utility shall provide the Applicant with specific information on the reason(s) for failure in writing. In addition, the Utility shall allow the Applicant to select one of the following, at the Applicant's option:

   a. Undergo Supplemental Review in accordance with Section III.D; or

   b. Continue evaluating the Application under Level 4, Section III.F.

   The Applicant must notify the Utility of its selection within ten (10) Business Days or the Application will be deemed withdrawn.

5. Approval: If the proposed interconnection passes the screens, the Application shall be approved, and the Utility will provide the Applicant an executable Interconnection Agreement within the following timeframes.

   a. If the proposed interconnection requires no construction of facilities by the Utility on its own system,[9] the Utility shall provide the Applicant with a copy of the Level 1 Application form, signed by the Utility, forming the Level 1 Interconnection Agreement, at the time the screen results are provided. If the Utility does not notify an Applicant whether an Application is approved or denied in writing within twenty (20) Business Days after notification of the Level 1 review results, the Interconnection Agreement signed by the Applicant as part of the Level 1 Application shall be deemed effective.

   b. If the proposed interconnection requires Interconnection Facilities or any distribution system modifications, the Application shall be

[9] This sub-provision (a) permits the installation of any metering or other commercial devices.

processed under Level 2 starting at Section III.B.5 and shall use the Interconnection Agreement in Attachment 5 associated with the Level 2 process. The Applicant shall be notified of this upon receiving notification of the screen results.

6. Unless extended by mutual agreement of the Parties, within six (6) months of formation of an Interconnection Agreement or six (6) months from the completion of any upgrades, whichever is later, the Applicant shall commence operation of the Generating Facility. The Applicant must provide the Utility with at least ten (10) Business Days' notice of the anticipated start date of the Generating Facility.

7. Within ten (10) Business Days of receiving the notice of the anticipated start date of the Generating Facility, the Utility may conduct an inspection of the Generating Facility at a time mutually agreeable to the Parties. If the Generating Facility passes the inspection, the Utility shall provide written notice of the passage within three (3) Business Days. If a Generating Facility initially fails a Utility inspection, the Utility shall offer to redo the inspection at the Applicant's expense at a time mutually agreeable to the Parties. If the Utility determines that the Generating Facility fails the inspection, the Utility must provide the Applicant with a written explanation detailing the reasons for the failure and any standards violated. If the Utility determines no inspection is necessary, it shall notify the Applicant within three (3) Business Days of receiving the notice of the anticipated start date.

8. An Applicant may begin interconnected operation of a Generating Facility provided that there is an Interconnection Agreement in effect, the Utility has received proof of the electrical code official's approval, and the Generating Facility has received written notice that it passed any inspection required by the Utility or received notice that none is required.[10] Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 6 or other inspector-provided documentation.

B. Level 2: Screening Criteria and Process for Generating Facilities Meeting Specified Size Criteria Up to 5 MW, Depending on Line Capacity and Distance from Substation

1. <u>Application</u>: An Applicant must submit a Level 2 Application, pursuant to Section I.C, using the standard form provided in Attachment 4 to these

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[10] Upon interconnected operation, the Applicant becomes an Interconnection Customer.

Interconnection Procedures, which may be sent electronically to a recipient designated by the Utility. A Utility may elect to charge a standard Application fee of up to $100 plus $10 per kW of Nameplate Rating up to a maximum of $2,000 for Level 2 review.

2. Applicable screens:

a. Facility Size: Generating Facility's Nameplate Rating does not exceed the limits identified in the table below, which vary according to the voltage of the line at the proposed Point of Interconnection. Generating Facilities located within 2.5 miles of a substation and on a main distribution line with minimum 600-amp capacity are eligible for Level 2 interconnection under higher thresholds.

Line Capacity	**Level 2 Eligibility**	
	Regardless of location	**On ≥ 600 amp line and ≤ 2.5 miles from substation**
≤ 4 kV	< 1 MW	< 2 MW
5 kV – 14 kV	< 2 MW	< 3 MW
15 kV – 30 kV	< 3 MW	< 4 MW
31 kV – 60 kV	≤ 4 MW	≤ 5 MW

b. For interconnection of a Generating Facility to a radial distribution circuit, the Generating Facility's Generating Capacity[11] aggregated with all other generation capable of exporting energy on a Line Section will not exceed 15 percent of the Line Section's[12] annual peak load as most recently measured at the substation or calculated for the Line Section.

c. The Generating Facility, aggregated with other generation on the

[11] Currently there is no best practice for how Screen 2.b should address the potential for Inadvertent Export from Generating Facilities incorporating the methods in Section IV.E.5 or IV.E.6 to limit their Generating Capacity. Whether the Generating Capacity, as proposed here, or Nameplate Rating is more appropriate for study under Screen 2.b (Section III.B.2.b) should be addressed as part of individual states' review and update of their interconnection procedures.

[12] Clarification of the relevant Line Section is sometimes necessary. If the point of common coupling is downstream of a line recloser, include those medium voltage (MV) Line Sections from the recloser to the end of the feeder. If the 15% criterion is passed for aggregate distributed generation and peak load at first upstream recloser, then the screen is passed. If the point of common coupling is upstream of all line reclosers (or none exist), include aggregate distributed generation relative to peak load of the feeder measured at the substation. If the 15% criterion is passed for the aggregate distributed generation and peak load for the whole feeder, then the screen is passed. A fuse must be manually replaced and is therefore not considered an automatic sectionalizing device.

distribution circuit, will not contribute more than 10 percent to the distribution circuit's maximum Fault Current at the point on the high-voltage (primary) level nearest the proposed Point of Common Coupling.

d. The Generating Facility, aggregated with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or Utility customer equipment on the system, to exceed 90 percent of the short circuit interrupting capability; nor is the interconnection proposed for a circuit that already exceeds 90 percent of the short circuit interrupting capability.

e. The Generating Facility complies with the applicable type of interconnection, based on the table below. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Utility's Electric Delivery System due to a loss of ground during the operating time of any Anti-Islanding function.

This screen does not apply to Generating Facilities with a gross rating of 11 kVA or less.[13]

Primary Distribution Line Configuration	**Type of Interconnection to be Made to the Primary Circuit**	**Results/Criteria**
Three-phase, three-wire	Any type	Pass Screen
Three-phase, four-wire	Single-phase, line-to-neutral	Pass Screen
Three-phase, four-wire (For any line that has such a section, or mixed three wire and four wire)	All Others	To pass, aggregate Generating Facility Nameplate Rating must be less than or equal to 10% of Line Section peak load

13 This screen allows utilities to continue to maintain safety, reliability and power quality by identifying generators that pose overvoltage concerns and mitigating them through a technical solution. At the same time, it avoids a full study when one is not needed, i.e., for Generating Facilities below 11 kVA and for Generating Facilities below 10 percent of the Line Section's peak load. Both California (Rule 21) and Hawaii (Rule 14H) take similar approaches.

f. If the Generating Facility is to be interconnected on a single-phase shared secondary, then the aggregate generation capacity on the shared secondary, including the Generating Facility's Generating Capacity, will not exceed 65 percent of the transformer nameplate power rating.

g. If the Generating Facility is single-phase and is to be interconnected on a transformer center tap neutral of a 240-volt service, its addition will not create an imbalance between the two sides of the 240-volt service of more than 20 percent of nameplate rating of the service transformer.

h. The Generating Facility's Nameplate Rating, in aggregate with other generation interconnected to the distribution low-voltage side of the substation transformer feeding the distribution circuit where the Generating Facility proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission voltage level busses from the Point of Common Coupling), or the proposed Generating Facility shall not have interdependencies, known to the Utility, with earlier-queued Interconnection Requests, that would necessitate further study.

i. The Generating Facility's Point of Common Coupling will not be on a transmission line.

j. For interconnection of a Generating Facility within a Spot Network or Area Network, the Generating Facility must be inverter-based and use a minimum import relay or other protective scheme that will ensure that power imported from the Utility to the network will, during normal Utility operations, remain above one percent of the network's maximum load over the past year or will remain above a point reasonably set by the Utility in good faith. At the Utility's discretion, the requirement for minimum import relays or other protective schemes may be waived.

3. <u>Time to process under screens</u>: Within fifteen (15) Business Days after the Utility notifies the Applicant that the Application is complete, the Utility shall notify the Applicant whether the Generating Facility meets all of the applicable Level 2 screens.

4. <u>Screens failure</u>: Despite the failure of one or more screens, the Utility, at its sole option, may approve the interconnection provided it concludes such approval is consistent with safety and reliability. If the Utility cannot determine that the Generating Facility may nevertheless be interconnected

consistent with safety, reliability, and power quality standards, the Utility shall provide the Applicant with detailed information on the reason(s) for failure in writing. In addition, the Utility shall allow the Applicant to select one of the following, at the Applicant's option:

a. Undergo Supplemental Review in accordance with Section III.D; or

b. Continue evaluating the Application under Level 4.

Upon receipt, the Applicant must notify the Utility of its selection within ten (10) Business Days or the Application will be deemed withdrawn.

5. Approval: If the proposed interconnection passes the screens, or fails the screens but passes Supplemental Review, the Application shall be approved, and the Utility will provide the Applicant an executable Interconnection Agreement within the following timeframes.

a. If the proposed interconnection requires no construction of facilities by the Utility,[14] the Utility shall provide the Interconnection Agreement to the Applicant within three (3) Business Days after the notification of Level 2 or Supplemental Review results.

b. If the proposed interconnection requires only Interconnection Facilities or Minor System Modifications, the Utility shall provide the Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, to the Applicant within fifteen (15) Business Days after the notification of the Level 2 or Supplemental Review results.

c. If the proposed interconnection requires more than Interconnection Facilities and Minor System Modifications, the Utility may elect to either provide an Interconnection Agreement along with a non-binding good faith cost estimate and construction schedule for such upgrades within twenty (20) Business Days after notification of the Level 2 or Supplemental Review results, or the Utility may notify the Applicant within five (5) Business Days of notification of Level 2 or Supplemental Review results that the Utility will need

[14] As under Level 1, this sub-provision (a) permits the installation of any metering or other commercial devices. If such devices are required, the three-day timeline for provision of the interconnection agreement still applies.

to complete a Facilities Study under Section III.F.5 to determine the necessary upgrades.

6. An Applicant that receives an Interconnection Agreement executed by the Utility shall have ten (10) Business Days to execute the agreement and return it to the Utility. An Applicant shall communicate with the Utility no less frequently than every six (6) months regarding the status of a proposed Generating Facility to which an Interconnection Agreement refers. Within twenty-four (24) months from an Applicant's execution of an Interconnection Agreement or six (6) months of completion of any upgrades, whichever is later, the Applicant shall commence operation of the Generating Facility. However, the Parties may mutually agree to an extension of this time if warranted, which shall not be unreasonably withheld. The Applicant must provide the Utility with at least ten (10) Business Days' notice of the anticipated start date of the Generating Facility.

7. Within ten (10) Business Days of receiving notice of the anticipated start date of the Generating Facility, the Utility may conduct an inspection at a time mutually agreeable to the Parties. If the Generating Facility passes the inspection, the Utility shall provide written notice of the passage within three (3) Business Days. If a Generating Facility initially fails the Utility inspection the Utility shall offer to redo the inspection at the Applicant's expense at a time mutually agreeable to the Parties. If the Utility determines that the Generating Facility fails the inspection, the Utility must provide the Applicant with a written explanation detailing the reasons and any standards violated. If the Utility determines no inspection is necessary, it shall notify the Applicant within three (3) Business Days of receiving the notice of the anticipated start date.

8. Upon Utility's receipt of proof of the electric code official's approval, an Applicant may begin interconnected operation of a Generating Facility, provided that there is an Interconnection Agreement in effect and that the Generating Facility has passed any inspection required by the Utility or received notice that none is required.[15] Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 6 or other inspector-provided documentation.

[15] Upon interconnected operation, the Applicant becomes an Interconnection Customer.

C. Level 3: Screening Criteria and Process for Non-Exporting Generating Facilities

An Applicant may use the Level 2 process for a Generating Facility, including an Energy Storage Device, that uses protective devices as set forth in Section IV.E to assure that power will not be exported from the Generating Facility (except for any Inadvertent Export). However, the Utility shall notify the Applicant whether the Generating Facility meets all of the applicable Level 2 screens within ten (10) Business Days.

Screen B.2.b shall not apply to Non-Exporting Generating Facilities incorporating the methods in Section IV.E, subparagraphs 1–3 to prevent the export of power across the Point of Common Coupling.

An Applicant proposing to interconnect a Non-Exporting Generating Facility to a Spot Network or an Area Network is not eligible to use Level 3.

D. Supplemental Review

1. Within twenty (20) Business Days an Applicant's election to undergo Supplemental Review, the Utility shall perform Supplemental Review using the screens set forth below, notify the Applicant of the results, and include with the notification a written report of the analysis and data underlying the Utility's determinations under the screens.

    a. Where twelve (12) months of Line Section minimum load data is available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the Generating Facility's Generating Capacity aggregated with all other generation capable of exporting energy on the Line Section[16] is less than 100 percent of the minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Generating Facility. If the minimum load data is not available, or cannot be calculated or estimated, the Generating Facility's Generating Capacity[17] aggregated with all other generation capable of exporting energy on the Line Section is less than 30 percent of the peak load for all Line Sections bounded by automatic

[16] See Footnote 8.

[17] Currently there is no best practice for how Supplemental Review Screen "a" should address the potential for Inadvertent Export from Generating Facilities incorporating the methods in Section IV.E.5 or IV.E.6 to limit their Generating Capacity. Whether the Generating Capacity, as proposed here, or Nameplate Rating is more appropriate for study under Screen "a" (Section III.D.1.a) be addressed as part of individual states' review and update of their interconnection procedures.

sectionalizing devices upstream of the proposed Generating Facility.

i. The type of generation used by the proposed Generating Facility will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (e.g., 8 a.m. to 6 p.m.), while all other generation uses absolute minimum load.

ii. Load that is co-located with load-following, non-exporting or export-limited generation should be appropriately accounted for.

iii. The Utility will not consider as part of the aggregate generation for purposes of this screen generating facility capacity, including combined heat and power (CHP) facility capacity, known to be already reflected in the minimum load data.

b. In aggregate with existing generation on the Line Section:

i. The voltage regulation on the Line Section can be maintained in compliance with relevant requirements under all system conditions;

ii. The voltage fluctuation is within acceptable limits as defined by IEEE Std 1547™; and

iii. The harmonic levels meet IEEE Std 1547™ limits at the Point of Interconnection.

c. The location of the proposed Generating Facility and the aggregate generation capacity on the Line Section do not create impacts to safety or reliability that cannot be adequately addressed without Application of Level 4. The Utility may consider the following factors and others in determining potential impacts to safety and reliability in applying this screen.

i. Whether the Line Section has significant minimum loading levels dominated by a small number of customers (i.e., several large commercial customers).

ii. If there is an even or uneven distribution of loading along the feeder.

iii. If the proposed Generating Facility is located in close proximity to the substation (i.e., ≤ 2.5 electrical line miles), and if the distribution line from the substation to the Generating Facility is composed of large conductor/feeder section (i.e., 600A class cable).

iv. If the proposed Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

v. If operational flexibility is reduced by the proposed Generating Facility, such that transfer of the Line Section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

vi. If the proposed Generating Facility utilizes Certified Anti-Islanding functions and equipment.

2. If the proposed interconnection passes the supplemental screens, the Application shall be approved and the Utility will provide the Applicant an executable Interconnection Agreement pursuant to the procedure set forth in Section III.B.5.

3. After receiving an Interconnection Agreement executed by the Utility, the Applicant shall proceed under the terms of the applicable level of review under which the Application was initially studied.

E. Applicant Options Meeting

If the Utility determines the Application cannot be approved without evaluation under Level 4 review, at the time the Utility notifies the Applicant of either the Level 1, 2, or 3 review or Supplemental Review results, the Utility shall provide the Applicant the option of proceeding to Level 4 review or of participating in an Applicant Options Meeting with the Utility to review possible Generating Facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Generating Facility to be connected safely and reliably. The Applicant shall notify the Utility in writing that it requests an Applicant Options Meeting or that it would like to proceed to Level 4 review within fifteen (15) Business Days of the Utility's notification, or the Application shall be deemed withdrawn. If the Applicant requests an Applicant Options Meeting, the Utility shall offer to convene a meeting at a mutually agreeable time within fifteen (15) Business Days of the Applicant's request.

F. Level 4: Study Process for All Other Generating Facilities

1. Application: An Applicant must submit a Level 4 Application using the

standard form provided in Attachment 4 to these Interconnection Procedures, which may be sent electronically to a recipient designated by the Utility. An Applicant whose Level 1, Level 2, or Level 3 Application was denied may request that the Utility treat that existing Application already in the Utility's possession as a new Level 4 Application. Within three (3) Business Days of receipt of the Application or the Applicant's request to use the existing Application, the Utility shall acknowledge receipt of the Application or transfer of an existing Application to the Level 4 process and notify the Applicant whether or not the Application is complete. If the Application is incomplete, the Utility shall provide a written list detailing all information that the Applicant must provide to complete the Application. The Applicant will have twenty (20) Business Days after receipt of the list to submit the listed information. Otherwise, the Application will be deemed withdrawn. The Utility shall notify the Applicant within three (3) Business Days of receipt of the revised Application whether the revised Application is complete or incomplete. The Utility may deem the Application withdrawn if it remains incomplete.

2. Fees: An Application fee shall not exceed $100 plus $10 per kW of Nameplate Rating up to a maximum of $2,000, as well as charges for actual time spent on any interconnection study. Costs for Utility facilities necessary to accommodate the Applicant's Generating Facility interconnection shall be the responsibility of the Applicant as set forth in the Interconnection Agreement.

3. Scoping Meeting: The Utility will conduct an initial review that includes a scoping meeting with the Applicant within ten (10) Business Days of determining that an Application is complete. The scoping meeting shall take place in person, by telephone, or electronically by a means mutually agreeable to the Parties. At the scoping meeting, the Utility shall provide pertinent information such as: the available Fault Current at the proposed location, the existing peak loading on the lines in the general vicinity of the proposed Generating Facility, and the configuration of the distribution line at the proposed Point of Interconnection. By mutual agreement of the Parties, the scoping meeting, System Impact Study or Facilities Study may be waived.

4. System Impact Study:

   a. If the Parties do not waive the System Impact Study, within five (5) Business Days of the completion of the scoping meeting (or five (5) Business Days after completion of the Application or final step in Levels 1 to 3 if scoping meeting is waived), the Utility shall provide the Applicant with an Interconnection System Impact Study Agreement in Attachment 7A, including a good faith estimate of the cost and time to undertake the System Impact Study.

b. A System Impact Study for a Generating Facility shall include a review of the Generating Facility's adherence to IEEE Std 1547™. For Generating Facility components that are Certified, the Utility may not charge the Applicant for review of those components in isolation.

c. Each Utility shall include in its compliance tariff a description of the various elements of a System Impact Study it would typically undertake pursuant to this Section, including:

i. Load-Flow Study

ii. Short-Circuit Study

iii. Circuit Protection and Coordination Study

iv. Impact on System Operation

v. Stability Study (and the conditions that would justify including this element in the System Impact Study)

vi. Voltage-Collapse Study (and the conditions that would justify including this element in the System Impact Study).

d. Once an Applicant delivers to the Utility an executed System Impact Study Agreement and payment in accordance with that agreement, the Utility shall conduct the System Impact Study. The System Impact Study shall be completed within forty (40) Business Days of the Applicant's delivery of the executed System Impact Study Agreement.[18] The System Impact Study provided to the Applicant shall include a description of the Utility's analysis, conclusions, and the reasoning supporting those conclusions.

5. Facilities Study:

a. If the Utility determines that Electric Delivery System modifications required to accommodate the proposed

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[18] If a proposed Application is found to require evaluation by an ISO/RTO or other external transmission provider there may need to be an adjustment to the timelines to allow said entity to evaluate the project. At all times Applicants should be kept informed of any delays on a regular basis.

interconnection are not substantial, the System Impact Study will identify the scope and cost of the modifications defined in the System Impact Study results, and no Facilities Study shall be required.

b. If the Utility determines that necessary modifications to the Utility's Electric Delivery System are substantial, the results of the System Impact Study will include an estimate of the cost of the Facilities Study and an estimate of the modification costs. The detailed costs of any Electric Delivery System modifications necessary to interconnect the Applicant's proposed Generating Facility will be identified in a Facilities Study to be completed by the Utility.

c. If the Parties do not waive the Facilities Study, within five (5) Business Days of the completion of the System Impact Study, the Utility shall provide an Interconnection Facilities Study Agreement provided in Attachment 7B, including a good faith estimate of the cost and time to undertake the Facilities Study.

d. Once the Applicant executes the Facilities Study Agreement and pays the Utility pursuant to the terms of that agreement, the Utility shall conduct the Facilities Study. The Facilities Study shall include a detailed list of necessary Electric Delivery System upgrades and an itemized cost estimate, breaking out equipment, labor, operation and maintenance and other costs, including overheads, for completing such upgrades, which may not be exceeded by 125 percent if actual upgrades are completed.[19] The Facilities Study shall also indicate the milestones for completion of the Applicant's installation of its Generating Facility and the Utility's completion of any Electric Delivery System modifications, and the milestones from the Facilities Study (if any) shall be incorporated into the Interconnection Agreement. The Facilities Study shall be completed within forty-five (45) Business Days of the Applicant's delivery of the executed Facilities Study agreement.

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19 In order for Applicant's to have confidence that they understand the costs of any necessary upgrades it is important that Utilities be expected to provide cost estimates within a reasonable margin of error. States such as California and Massachusetts have implemented binding cost envelopes, while other states such as Minnesota are requiring careful tracking of costs that exceed a specified margin.

6. Interconnection Agreement:

   a. Within five (5) Business Days of completion of the last study, the Utility shall execute and send the Applicant an Interconnection Agreement using the standard form agreement provided in Attachment 5 of these Interconnection Procedures, which shall incorporate the milestones (if any) from the Facilities Study. The Interconnection Agreement shall include an itemized quote, including overheads, for any required Electric Delivery System modifications, subject to the cost limit set by the Facilities Study cost estimate.

   b. Within forty (40) Business Days of the receipt of an Interconnection Agreement, the Applicant shall execute and return the Interconnection Agreement and notify the Utility of the anticipated start date of the Generating Facility. Unless the Utility agrees to a later date or requires more time for necessary modifications to its Electric Delivery System, the Applicant shall identify an anticipated start date that is within twenty-four (24) months of the Applicant's execution of the Interconnection Agreement. However, the Parties may mutually agree to an extension of this time if needed, which shall not be unreasonably withheld. The Applicant shall notify the Utility if there is any change in the anticipated start date of interconnected operations of the Generating Facility.

7. Inspection:

   a. The Utility shall inspect the completed Generating Facility installation for compliance with requirements and shall attend any required commissioning tests pursuant to IEEE Std 1547™. For systems greater than 10 MW, IEEE Std 1547™ may be used as guidance. The Utility shall conduct the inspection within ten (10) Business Days of receiving the notice of the anticipated start date at a time mutually agreeable to the Parties. If the Generating Facility passes the inspection, the Utility shall provide written notice of the passage within three (3) Business Days. If a Generating Facility initially fails a Utility inspection, the Utility shall offer to redo the inspection at the Applicant's expense at a time mutually agreeable to the Parties. If the Utility determines that the Generating Facility fails the inspection, it must provide a written explanation detailing the reasons and any standards violated. Provided that any required commissioning tests are satisfactory, the Utility shall notify the Applicant in writing within five (5) Business Days of completion of the inspection that operation of the Generating Facility is approved.

8. Operation:

   a. Upon the Utility's receipt of proof of the electric code official's approval, an Applicant may begin interconnected operation of a Generating Facility, provided that there is an Interconnection Agreement in effect and that the Generating Facility has passed any inspection required by the Utility. Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 6 or other inspector-provided documentation.

IV. GENERAL PROVISIONS AND REQUIREMENTS

A. Timelines and Extensions

1. The Utility shall make reasonable efforts to meet all timelines set by these Interconnection Procedures.[20] If the Utility cannot meet a timeline, the Utility shall notify the Applicant in writing within one (1) Business Day after the missed deadline. The notification shall explain the reason for the Utility's failure to meet the deadline and provide an estimate of when the step will be completed. The Utility shall keep the Applicant updated of any changes in the expected completion date.

2. The Applicant may request in writing the extension of one timeline set by these Interconnection Procedures. The requested extension may be for up to one-half of the time originally allotted (e.g., a ten (10) Business Day extension for a twenty (20) Business Day timeframe). The Utility shall not unreasonably refuse this request. If further timeline extensions are necessary, the Applicant may request an extension in writing to the Interconnection Ombudsperson, who shall grant or deny the request, if it is reasonable, within three (3) Business Days.

B. Online Applications and Electronic Signatures

1. Each Utility shall allow interconnection Applications to be submitted via email or through the Utility's website.

[20] Providing utilities some level of flexibility in meeting timelines in order to manage staffing in times of fluctuating application submittal rates and need to manage system emergencies is typical in most states. However, since the timelines are binding on applicants and utility delays can have real cost implications for projects it is important to ensure utilities understand there is some expectation of maintaining compliance with the timelines set forth within. Some states have begun to implement financial rewards and penalties for steady rates of compliance, while others are considering rigorous tracking to ensure Commissions are at least aware of where delays may be occurring.

2. Each Utility shall dedicate an easy to locate page on their website to interconnection procedures. The relevant website page shall include:

    a. These Interconnection Procedures and attachments in an electronically searchable format,

    b. The Utility's Interconnection Application forms in a format that allows for electronic entry of data,

    c. The Utility's Interconnection Agreements, and

    d. The Utility's point of contact for submission of Interconnection Applications including email and phone number.

3. Each Utility shall allow electronic signatures to be used for interconnection Applications and Agreements.

C. Dispute Resolution

1. The Parties agree to attempt to resolve all disputes arising out of the interconnection process and associated study and interconnection agreements according to the provisions of this Section.

2. In the event of a dispute, the disputing Party shall provide the other Party a written Notice of Dispute containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the disputing Party that it is invoking the procedures under this Section. The notice shall be sent to the non-disputing Party's email address and physical address set forth in the Interconnection Agreement or Application, if there is no Interconnection Agreement. A copy of the notice shall also be sent to Interconnection Ombudsperson.[21]

    The non-disputing Party shall acknowledge the notice within three (3) Business Days of its receipt and identify a representative with the authority to make decisions for the non-disputing Party with respect to the dispute.

3. If the dispute is principally related to one or both Parties' compliance with timelines specified in these Interconnection Procedures or associated agreements, the Parties shall seek assistance from Interconnection

[21] An Interconnection Ombudsperson can be designated by the Commission (typically Commission staff) to help track and facilitate the efficient and fair resolution of disputes. Some states have begun to look at processes which engage a technical master to help resolve disputes related to engineering questions that may arise in the interconnection process.

Ombudsperson if the Parties cannot mutually resolve the dispute within eight (8) Business Days.[22]

4. If the dispute is not principally related to one or both Parties' compliance with a timeline, then the non-disputing Party shall provide the disputing Party with all relevant regulatory and/or technical details and analysis regarding any Utility interconnection requirements under dispute within ten (10) Business Days of the date of the notice of dispute. Within twenty (20) Business Days of the date of the notice of dispute, the Parties' authorized representatives shall meet and confer to try to resolve the dispute. Parties shall operate in good faith and use best efforts to resolve the dispute.

5. If a resolution is not reached in thirty (30) Business Days from the date of the notice of dispute, either (1) a Party may request to continue negotiations for an additional twenty (20) Business Days, or (2) the Parties may by mutual agreement make a written request for mediation to the Interconnection Ombudsperson. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

6. If the results of the mediation are not accepted by one or more Parties and there is still disagreement, the dispute shall proceed to the formal complaint process provided by the Commission.[23]

7. At any time, either Party may file a complaint before the Commission pursuant to its rules.

8. If neither Party elects to seek assistance from the Commission, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

D. Utility Reporting Requirement

Each Utility shall submit to the Commission two times per year and make available to the public on its website an interconnection report. The report shall contain information in the form required by Attachment 9, including relevant totals for both the year and the most recent reporting period.

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22 The duration of the typical dispute resolution process is generally considered to be too long to be effective in assisting parties with timeline disputes. Thus, it is helpful to engage an Ombudsperson earlier on to facilitate disputes related to timelines where possible.

23 This section must be modified if the relevant Commission does not have a formal complaint process.

E. Limited-Export and Non-Exporting Generating Facilities

If a Generating Facility uses any configuration or operating mode in this Section IV.E, subparagraphs 1 through 6 to limit the export of electrical power across the Point of Common Coupling, then the Generating Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export from a Generating Facility must comply with the limits in subparagraphs 5 or 6. The Generating Capacity specified by the Interconnection Customer in the Application will subsequently be included as a limitation in the Interconnection Agreement. Other means not listed in Section IV.E may be utilized to limit export if mutually agreed upon by the Utility and Applicant.

1. Reverse Power Protection: To ensure power is never exported across the Point of Common Coupling, a reverse power Protective Function may be provided. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay.

2. Minimum Power Protection: To ensure at least a minimum amount of power is imported across the Point of Common Coupling at all times (and, therefore, that power is not exported), an under-power Protective Function may be provided. The default setting for this Protective Function shall be 5% (import) of the generating unit's total Nameplate Rating, with a maximum 2.0 second time delay.

3. Relative Distributed Energy Resource Rating: This option requires the Nameplate Rating of the generating unit, minus any auxiliary load, to be so small in comparison to its host facility's minimum load that the use of additional Protective Functions is not required to ensure that power will not be exported to the Electric Delivery System. This option requires the generating unit capacity to be no greater than 50% of the Interconnection Customer's verifiable minimum Host Load over the past 12 months.

4. Configured Power Rating: A reduced output rating utilizing the power rating configuration setting may be used to ensure the DER does not generate power beyond a certain value lower than the Nameplate Rating.[24]

5. Limited Export Utilizing Inverters or Control Systems: Generating Facilities may utilize, a Nationally Recognized Testing Laboratory

[24] The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE Std 1547™-2018, as described in subclause 10.4. A local DER communication interface is not required to utilize the configuration setting as long as it can be set by other means.

("NRTL") Certified Power Control System and inverter system that results in the Generating Facility disconnecting from the Electric Delivery System, ceasing to energize the Electric Delivery System or halting energy production within 2 seconds if the period of continuous Inadvertent Export exceeds 30 seconds.[25] Failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the Generating Facility entering an operational mode where no energy is exported across the Point of Common Coupling to the Electric Delivery System.

6. Limited Export Using Mutually Agreed-Upon Means: Generating Facilities may be designed with other control systems and/or Protective Functions to limit export and Inadvertent Export to levels mutually agreed upon by the Applicant and the Utility. The limits may be based on technical limitations of the Interconnection Customer's equipment or the Electric Delivery System equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the Interconnection Customer shall use an internal transfer relay, energy management system, or other customer facility hardware or software.

F. Miscellaneous Requirements

1. Applicant is responsible for construction of the Generating Facility and obtaining any necessary local code official approval (electrical, zoning, etc.).

2. Applicant shall conduct the commissioning test pursuant to the IEEE Standard 1547™ and comply with all manufacturer requirements.

3. To assist Applicants in the interconnection process, the Utility shall designate an employee or office from which basic information on interconnections can be obtained. Upon request, the Utility shall provide interested Applicants with all relevant forms, documents and technical requirements for filing a complete Application. Upon an Applicant's request, the Utility shall meet with an Applicant at the Utility's offices or by telephone prior to submission for up to one hour for Level 1 Applicants and two hours for other Applicants.

[25] Some states impose an additional limitation on the amount of Inadvertent Export energy, e.g., 3 hours per month multiplied by the Generating Facility's Nameplate Rating, to ensure operation of the Generating Facility consistent with the terms of the Interconnection Application and/or Agreement. Systems tested to a standardized protocol for inadvertent export, such as that available from UL for Power Control Systems, may not be required to conform to this additional limitation. The UL 1741 Certification Requirement Decision on Power Control Systems may be used before a standard is available.

4. The authorized hourly rate for engineering review under Supplemental Review or Level 4 shall be $100 per hour.[26]

5. A Utility shall not require an Applicant to install additional controls (other than a utility accessible disconnect switch for non-inverter-based Generating Facilities[27]), or to perform or pay for additional tests not identified herein to obtain approval to interconnect.

6. A Utility may only require an Applicant to purchase insurance covering Utility damages, and then only in the following amounts:[28]

   a. For non-inverter-based Generating Facilities:

Nameplate Rating > 5 MW	$3,000,000
2 MW < Nameplate Rating $\leq$ 5 MW	$2,000,000
500 kW < Nameplate Rating $\leq$ 2 MW	$1,000,000
50 kW < Nameplate Rating $\leq$ 500 kW	$500,000
Nameplate Rating $\leq$ 50 kW	Typical Homeowners[29]

   b. For inverter-based Generating Facilities:

Nameplate Rating > 5 MW	$2,000,000
1 MW < Nameplate Rating $\geq$ 5 MW	$1,000,000
Nameplate Rating $\geq$ 1 MW	no insurance

7. Additional protection equipment not included with the Interconnection Equipment Package may be required at the Utility's discretion as long as the performance of an Applicant's Generating Facility is not negatively impacted and the Applicant is not charged for any equipment that provides protection that is already provided by Certified interconnection equipment Certified.

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[26] The fixed hourly fee for engineering review may be adjusted to reflect standard rates in each state, but the hourly charge should be fixed so there are no disparities among Utilities or between different Applications to ensure fair treatment.

[27] A number of states have allowed Utilities to require external disconnect switches but specified that the Utility must reimburse Applicants for the cost of the switch. Several states have specified that an external disconnect switch may not be required for smaller inverter-based Generating Facilities. Recognizing that non-inverter-based Generating Facilities might present a hazard, Utilities may require a switch for these Generating Facilities.

[28] Insurance requirements are not typically separated by inverter and non-inverter-based Generating Facilities. However, concerns seem to center on the potential for non-inverter-based systems to cause damage to utility property. To IREC's knowledge, there has never been a claim for damages to a utility's property caused by an inverter-based system, and it seems that there is little theoretical potential for damage to a utility's property caused by an inverter-based system of less than a megawatt.

[29] The amount required by a typical homeowners insurance policy is generally adequate here, this amount may vary by state.

8. Metering and Monitoring shall be as set forth in the Utility's tariff for sale or exchange of energy, capacity or other ancillary services.[30]

9. Telemetry may be required by the Utility for Generating Facilities with a Nameplate rating of 1 MVA or higher. See the Utility's interconnection handbook for details on equipment requirements.

10. Once an interconnection has been approved under these procedures, a Utility shall not require an Interconnection Customer to test its Generating Facility except that the Utility may require any manufacturer-recommended testing and:

    a. For Levels 2 and 3, the Utility may require periodic testing to verify adherence to the interconnection requirements. The frequency of periodic testing will be specified in the Utility's interconnection handbook or other appropriate documentation.

    b. For Level 4, all interconnection-related protective functions and associated batteries shall be periodically tested at intervals specified by the manufacturer, system integrator, or authority that has jurisdiction over the interconnection. Periodic test reports or a log for inspection shall be maintained.

    c. For functional software or firmware changes, hardware changes, protection settings or function changes, or changes to operating modes, the Utility may require retesting to ensure the Generating Facility still meets the requirements of IEEE Std 1547™. When required, the updated Generating Facility configuration and testing results shall be documented and submitted to the Utility.

11. A Utility shall have the right to inspect an Interconnection Customer's Generating Facility before and after interconnection approval is granted, at reasonable hours and with reasonable prior notice provided to the Interconnection Customer. If the Utility discovers an Interconnection Customer's Generating Facility is not in compliance with the requirements of IEEE Standard 1547™, and the non-compliance adversely affects the safety or reliability of the electric system, the Utility may require disconnection of the Interconnection Customer's Generating Facility until the Generating Facility complies with IEEE Standard 1547™.

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[30] Metering or other revenue based technical requirements that are necessary to qualify for rates or procurement programs such as Net Energy Metering ("NEM") should be addressed in the tariffs, regulations or rules related to those programs rather than in the interconnection procedures which are drafted to be agnostic with respect to the rates and procurement programs projects may utilize.

12. The Interconnection Customer may disconnect the Generating Facility at any time without notice to the Utility and may terminate the Interconnection Agreement at any time with one day's notice to the Utility.

13. On the Application form, an Applicant may designate a representative to process an Application on Applicant's behalf, and an Interconnection Customer may designate a representative to meet some or all of the Interconnection Customer's responsibilities under the Interconnection Agreement.[31]

14. For a Generating Facility offsetting part or all of the load of a utility customer at a given site, that customer is the Interconnection Customer and that customer may assign its Interconnection Agreement to a subsequent occupant of the site.[32] For a Generating Facility providing all of its energy directly to a Utility, the Interconnection Customer is the owner of the Generating Facility and may assign its Interconnection Agreement to a subsequent owner of the Generating Facility. Assignment is only effective after the assignee provides written notice of the assignment to the Utility and agrees to accept the Interconnection Customer's responsibilities under the Interconnection Agreement.

15. If the Applicant is seeking approval for an Energy Storage Device, a separate application for the interconnection of new or modified load will not be required as a result of a customer's application for interconnection under these Interconnection Procedures and instead the review shall occur under these Interconnection Procedures.[33]

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[31] In the most common case, a residential customer may designate an installer as the representative. For larger Generating Facilities, a third-party owner might be the designated representative.

[32] In the most common case, an Interconnection Customer is a homeowner and this clause allows the homeowner to sell the home and assign the Agreement to the new owner. In many commercial situations, the Interconnection Customer is a lessee and this clause allows that lessee to move out at the end of a lease and assign the Agreement to a new lessee.

[33] In most states there are separate procedures for customers seeking to modify or connect new load. Rather than requiring two different application forms, timelines, etc. this review can be completed all through these Interconnection Procedures for energy storage customers that may charge from the grid. Note that further clarification may be required if new or expanded load customers are typically given a credit for any utility work or if cost allocation rules otherwise diverge between the procedures for interconnecting new load versus new generation.

Attachment 1

Glossary of Terms

"Anti-Islanding" means a control scheme installed as part of the Generating or Interconnection Facility that senses and prevents the formation of an Unintended Island.

"Applicant" means a person or entity that has filed an Application to interconnect a Generating Facility to an Electric Delivery System. For a Generating Facility that will offset part or all of the load of a Utility customer, the Applicant is that customer, regardless of whether the customer owns the Generating Facility or a third party owns the Generating Facility.[1] For a Generating Facility selling electric power to a Utility, the owner of the Generating Facility is the Applicant.

"Applicant Options Meeting" has the meaning provided in Section III.E of these procedures.

"Application" means the Applicant's request, in accordance with these Interconnection Procedures, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Utility's Electric Distribution System.

"Area Network" means a section of an Electric Delivery System served by multiple transformers interconnected in an electrical network circuit generally used in large, densely populated metropolitan areas in order to provide high reliability of service and having the same definition as the term "secondary grid network" as defined in IEEE Std 1547™.

"Auxiliary Load" means electrical power consumed by any auxiliary equipment necessary to operate the Generator.

"Business Day" means Monday through Friday, excluding Federal and State Holidays.

"Certified" means a piece of equipment has been tested in accordance with the applicable requirements of IEEE Std 1547™ and IEEE Std 1547.1™ by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify equipment pursuant to the applicable standard and the equipment has been labeled and is publicly listed by such NRTL at the time of the interconnection application. UL 1741 is one such standard that ensures compliance with IEEE Std 1547™ and IEEE Std 1547.1™ and is applicable only to inverters. There may be additional or separate certifications available for specific pieces of equipment.

[1] For a variety of reasons, a Generating Facility may be owned by a third party that contracts to sell energy or furnish the Generating Facility to the Utility's customer. In those cases, the Utility's customer is still the Applicant under this Agreement, though the Applicant may choose to designate the owner as Applicant's representative. Customers may also designate on the Application form installers or others to act on their behalf in the process.

"Commission" means the *[insert name of the state utility commission or equivalent]*.

"Customer" means the entity that receives or is entitled to receive Distribution Service through the Utility's Electric Delivery System or is a retail customer of the Utility.

"Distribution Service" means the service of delivering energy over the Electric Delivery System pursuant to the approved tariffs of the Utility other than services directly related to the interconnection of a Generating Facility under these Interconnection Procedures.

"Electric Delivery System" means the equipment operated and maintained by a Utility to deliver electric service to end-users, including without limitation transmission and distribution lines, substations, transformers, Spot Networks and Area Networks.

"Energy Storage Device" means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time. For purposes of these Procedures, an Energy Storage Device can be considered a Generating Facility.

"Facilities Study" has the meaning provided in Section III.F.5 and Attachment 7B of these procedures.

"Fault Current" means electrical current that flows through a circuit and is produced by an electrical fault, such as to ground, double-phase to ground, three-phase to ground, phase-to-phase, and three-phase. A Fault Current is several times larger in magnitude than the current that normally flows through a circuit.

"Generating Capacity" means the maximum Nameplate Rating of a Generating Facility in alternating current (AC), except that where such capacity is limited by any of the methods of limiting electrical export in Section IV.E, the Generating Capacity shall be the net capacity as limited through the use of such methods (not including Inadvertent Export).

"Generating Facility" means the equipment used by an Interconnection Customer to generate, store, manage, interconnect and monitor electricity. A Generating Facility includes an Interconnection Equipment Package.

"IEEE" means the Institute of Electrical and Electronic Engineers.

"IEEE Standards" means the standards published by the IEEE, available at www.ieee.org.

"Inadvertent Export" means the unscheduled export of active power from a Generating Facility, exceeding a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.

"Interconnection Agreement" means a standard form agreement between an Interconnection Customer and a Utility governing the interconnection of a Generating Facility to a Utility's

Electric Delivery System, as well as the ongoing operation of the Generating Facility after it is interconnected. For Level 1, the standard form Interconnection Agreement is incorporated with the Level 1 Application, provided in Attachment 3 to these Interconnection Procedures. For Levels 2, 3 or 4, the standard form Interconnection Agreement is provided in Attachment 4 to these Interconnection Procedures.

"Host Load" means the electrical power, less the Generator Auxiliary Load, consumed by the Customer, to which the Generating Facility is connected.

"Interconnection Customer" means an Applicant that has entered into an Interconnection Agreement with a Utility to interconnect a Generating Facility and has interconnected that Generating Facility.

"Interconnection Equipment Package" means a group of components connecting an electric generator with an Electric Delivery System, and includes all interface equipment including switchgear, inverters or other interface devices. An Interconnection Equipment Package may include an integrated generator or electric source.[2]

"Interconnection Facilities" means the electrical wires, switches, and related equipment that are required in addition to the facilities required to provide electric Distribution Service to a Customer to allow interconnection. Interconnection Facilities may be located on either side of the Point of Common Coupling as appropriate to their purpose and design. Interconnection Facilities may be integral to a Generating Facility or provided separately. Interconnection Facilities may be owned by either the Interconnection Customer or the Utility.

"Interconnection Procedures" means these procedures including attachments.

"Island" or "Islanding" means a condition on the Utility's Electric Delivery System in which one or more Generating Facilities deliver power to Customers using a portion of the Utility's Electric Delivery System that is electrically isolated from the remainder of the Utility's Electric Delivery System.

"Level 1" has the meaning provided in Section III.A and Attachment 3 of these procedures.

"Level 2" has the meaning provided in Section III.B and Attachment 4 and Attachment 5 of these procedures.

"Level 3" has the meaning provided in Section III.C and Attachment 4 and Attachment 5 of these procedures.

"Level 4" has the meaning provided in Section III.F and Attachment 4 and Attachment 5 of these procedures.

2 The most common Interconnection Equipment Package is an inverter. However, a solar array and an inverter can be bundled as a complete Interconnection Equipment Package. In that case, the Generating Facility would simply be the Interconnection Equipment Package.

"Limited Export" means the exporting capability of a Generating Facility whose Generating Capacity is limited by the use of any configuration or operating mode described in Section IV.E.

"Line Section" means that portion of the Utility's Electric Delivery System connected to a Customer bounded by automatic sectionalizing devices or the end of the distribution line.

"Material Modification" means a modification that has a material impact on the cost or timing of processing an Application with a later queue priority date or a change in the Point of Interconnection. A Material Modification does not include, for example, (a) a change of ownership of a Generating Facility, (b) a change or replacement of generating equipment that is a like-kind substitution in size, ratings, impedances, efficiencies, or capabilities of the equipment specified in the original Application, or (c) a reduction in the output of the Generating Facility of 10% or less.[3]

"Minor System Modifications" means modifications to a Utility's Electric Delivery System that involve little work or low costs (e.g., less than eight hours of work or $5,000 in materials). Minor System Modifications include, but are not limited to, activities like changing the fuse in a fuse holder cut-out or changing the settings on a circuit recloser.

"Nameplate Rating" means the sum total capacity of all of a Generating Facility's constituent generating units, regardless of whether it is limited by any of the methods in Section IV.E.

"Net Rating" means the Nameplate Rating of the Generating Facility minus the consumption of electrical power of the Auxiliary Load.

"Non-Export" or "Non-Exporting" means when the Generating Facility is sized and designed using any of the methods in Section IV.E, such that the output is used for Host Load only and no electrical energy (except for any Inadvertent Export) is transferred from the Generating Facility to the Electric Delivery System.

"Parties" means the Applicant and the Utility in a particular Interconnection Agreement. "Either Party" refers to either the Applicant or the Utility.

"Point of Common Coupling" means the point of connection between the Utility's Electric Delivery System and the Customer's electrical facilities.

"Point of Interconnection" means the point where the Interconnection Facilities connect with the Utility's Electric Delivery System. This may or may not be coincident with the Point of Common Coupling.

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3 Different jurisdictions have taken varying approaches to defining what is a "material modification." Some states, like North Carolina and Minnesota, provide extensive examples of what is, and is not, a material modification, to set expectations and guide decision-making. Other states, like California, provide more limited guidance, leaving the determination more to utility discretion.

"Power Control System" means systems or devices which electronically limit or control steady state currents to a programmable limit.

"Power Rating Configuration Setting" means the as-configured value of the active or apparent power ratings which is used as the rating within the Generating Facility. This alternative rating is associated with the nameplate information required by IEEE Std 1547™-2018 subclause 10.3, as allowed by subclause 10.4.

"Pre-Application Report" has the meaning provided in Section II.B of these procedures.

"Pre-Application Report Request" has the meaning provided in Section I.A of these procedures.

"Protective Function" means the equipment, hardware and/or software in a Generating Facility (whether discrete or integrated with other functions) whose purpose is to protect against conditions that, if left uncorrected, could result in harm to personnel, damage to equipment, loss of safety or reliability, or operation outside pre-established parameters required by the Interconnection Agreement.

"Spot Network" means a section of an Electric Delivery System that uses two or more inter-tied transformers to supply an electrical network circuit. A Spot Network is generally used to supply power to a single Utility customer or to a small group of Utility customers, and has the same meaning as the term is used in IEEE Std 1547™.

"Supplemental Review" has the meaning provided in Section III.D of these procedures.

"System Impact Study" has the meaning provided in Section III.F.4 and Attachment 7A of these procedures.

"UL" means the company by that name which has established standards available at http://ulstandardsinfonet.ul.com/ that relate to components of Generating Facilities.

"Unintended Island" means the creation of an Island without the approval of the Utility, usually following a loss of a portion of the Utility's Electric Delivery System.

"Utility" means an operator of an Electric Delivery System.[4]

[4] Some interconnection procedures reference the operator of the Electric Delivery System as the "Company" or the "Electric Delivery Company (EDC)." Here the term "Utility" is meant to include all investor-owned and public utilities, including cooperatives, municipal utilities and public utility districts. In deregulated states, the "wires" company is the Utility while the energy provider is not.

Attachment 2

Codes and Standards[1]

1. IEEE Std 1547™, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces[2];
2. IEEE Std 1547.1™, Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces;
3. ANSI C84.1, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)
4. IEC TR 61000-3-7, Electromagnetic compatibility (EMC) - Part 3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems;
5. IEC 61000-4-3, Electromagnetic compatibility (EMC) - Part 4-3: Testing and measurement techniques - Radiated, radio-frequency, electromagnetic field immunity test;
6. IEC 61000-4-5, Electromagnetic compatibility (EMC) - Part 4-5: Testing and measurement techniques – Surge immunity test;
7. IEEE Std 1547.2™, Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems;
8. IEEE Std 1547.3™, Guide for Monitoring Information Exchange and Control of DR Interconnected with Electric Power Systems;
9. IEEE Std 1547.4™, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island System with Electric Power Systems;

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[1] The standard documents have intentionally been listed without the respective publication year. Practice across states and utilities varies in this regard, and an intentional choice should be made whether or not to include the version or year of publication. If the particular version is included in the list of standards, then the interconnection procedures may need updating on a more regular basis as new versions become available and need to be referenced. However, technical requirements of different standard versions can vary significantly. Thus, while these Model Interconnection Procedures do not contain specific technical requirements based on standards, those documents that do contain specific technical requirements (such as those based on IEEE Std 1547™) should be reviewed when a new version of a standard becomes available to ensure that applicable elements of the new version are properly incorporated.

[2] IEEE 1547 provides: "For DER interconnections that include individual synchronous generator units rated 10 MVA and greater, and where the requirements of this standard conflict with the requirements of IEEE Std C50.12 or IEEE Std C50.13, the requirements of IEEE Std C50.12 or IEEE Std C50.13, as relevant to the type of synchronous generator used, shall prevail."

10. IEEE Std 1547.6™, IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks;

11. IEEE Std 1547.7™, IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection;

12. IEEE Std 519™, IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems;

13. IEEE Std 1453™, IEEE Recommended Practice for the Analysis of Fluctuating Installation on Power Systems;

14. IEEE Std C37.90™, IEEE Standard for Relay Systems Associated with Electric Power Apparatus;

15. IEEE Std C37.90.1™, IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems;

16. IEEE Std C37.90.2™, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers;

17. IEEE C37.95™, IEEE Guide for Protective Relaying of Utility-Consumer Interconnections;

18. IEEE Std C50.12™, IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above;

19. IEEE Std C50.13™, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above;

20. IEEE Std C62.41.2™, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits;

21. IEEE Std C62.45™, IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and Less) AC Power Circuits;

22. IEEE Std C62.92.1™, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems—Part I: Introduction;

23. IEEE Std C62.92.2™, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II – Grounding of Synchronous Generator Systems;

24. IEEE Std C62.92.6™, IEEE Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI--Systems Supplied by Current-Regulated Sources;

25. IEEE Std 2030.5™, IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard;

26. IEEE Std 1815™, IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3); and

27. UL 1741, Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources. UL 1741 compliance must be recognized or Certified by a Nationally Recognized Testing Laboratory as designated by the U.S. Occupational Safety and Health Administration.[3]

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[3] Inverter certification to UL 1741 is routinely required. Some states have established lists of Certified inverters with UL 1741 certification as the primary criterion.

Attachment 3

Level 1 Application and Interconnection Agreement for Inverter-Based Generating Facilities Not Greater than 25 kW

This Application is complete when it provides all applicable and correct information required below and includes a one-line diagram if required by the Utility and a standard Processing Fee of up to $100, if required by the Utility. This form should be made available in an electronically fillable format and it shall be permissible to submit the form with electronic signatures.

Applicant:

Name: ____

Address: ____

City: State, Zip: ____

Telephone (Day): ____________________________ (Evening): ___________________________

Email Address: ____

Utility Customer Number (if applicable): ___________________________________

Electricity Provider (if different from Utility):_______________________________

Representative: (if different from Applicant)

Name: ____

Address: ____

City, State, Zip: ____

Telephone (Day): ____________________________ (Evening): ___________________________

Email Address: ____

Generating Facility Specifications:

All power ratings should be listed in AC throughout.

Location (if different from above): _______________________________________

Facility Owner (include percent ownership by any electric utility): ________________________

____

Applicant Load: (kW) _____________ (if none, so state)

Typical Reactive Load (if known): ___________________

Total number and type of generators to be interconnected pursuant to this Application: ________

____

Total number of inverters to be interconnected pursuant to this Application: _________________

Total Aggregate Nameplate Rating for all Generators: (kW) _________ (kVA)_____________

Generating Capacity[1]: (kW) _______________ (kVA) ___________________

Limited-Export / Non-Export / Limited-Import Data:

If multiple export control systems are used, provide for each control system and use additional sheets if needed.

Is export controlled to less than the Total Aggregate Nameplate Rating? Yes: ______ No: ____

Method of export limitation: Power Control System / Reverse Power Protection / Minimum Power Protection / Other (describe): ________________________________

Export controls are applied to how many generators? Multiple: _____ One: _____

If Power Control System is used, open loop response time: _______________ (s)

Power Control System output limit setting: (kW) ___________ (kVA) ___________

Energy Storage System Power Control System operating mode:

Unrestricted: ________ Export Only: ________ Import Only: ________ No Exchange: ________

Describe which Generators the export control system controls:___________________________

____

Individual Generator Data:

Provide for each Generator, use additional sheets if needed.

Generator Technology: Photovoltaic / Turbine/ Fuel Cell / Energy Storage/ Other (describe): ___

____

Generator[2] Manufacturer, Model Name & Number: ___________________________________

Version Number: ____

Energy Source: Solar / Wind / Hydro / Other (describe): _______________________________

If Energy Storage, usable capacity at maximum discharge rate: ____________________ (kWh)

Individual Inverter Data (if any):

Provide for each inverter, use additional sheets if needed.

Inverter Manufacturer: ____

Model Name & Number: ____

1 As limited by any export controls.

2 E.g. the solar PV module manufacturer, battery manufacturer, etc.

Version Number:____

Nameplate Rating: (kW) (kVA) (AC Volts): ____

Rated Power Factor: (Underexcited) _________________ (Overexcited) __________________

Minimum Power Factor: (Underexcited) ______________ (Overexcited) __________________

Single phase: _____ Three phase: _____ (check one)

List of adjustable set points for the protective equipment or software: ______________________

____

Do export controls apply to this inverter? Yes:_______________ No: ______________________

Single Phase: __________ Three Phase: __________ (check one)

Max design fault contribution current (choose one): Instantaneous: _________ RMS: __________

Is the inverter UL1741 Listed? Yes: ______ No: ______

If Yes, attach evidence of UL1741 listing.

If required by the Utility, attach a one-line diagram of the Generating Facility.

Applicant Signature (may be electronic)

I designate the individual or company listed as my Representative to serve as my agent for the purpose of coordinating with the Utility on my behalf through the interconnection process (*see* Procedures Section IV.F.13). INITIAL: __________

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the terms and conditions for a Level 1 Interconnection Agreement, provided on the following pages.

Signed: ____

Title: ____

Date: ______________________________________

Operation is contingent on Utility approval to interconnect the Generating Facility.

Utility Signature (may be electronic)

Interconnection of the Generating Facility is approved contingent upon the terms and conditions for a Level 1 Interconnection Agreement, provided on the following pages ("Agreement").

Utility Signature: ____

Title: ________________________________ Application ID number: _______________

Date: ________________________________

Utility waives inspection? Yes ________________ No _______

Terms and Conditions for a Level 1 Interconnection Agreement

1.0 Construction of the Generating Facility
After the Utility executes the Interconnection Agreement by signing the Applicant's Level 1 Application, the Applicant may construct the Generating Facility, including interconnected operational testing not to exceed two hours.

2.0 Interconnection and Operation
The Applicant may operate the Generating Facility and interconnect with the Utility's Electric Delivery System once all of the following have occurred:

2.1. The Generating Facility has been inspected and approved by the appropriate local electrical wiring inspector with jurisdiction, and the Applicant has sent documentation of the approval to the Utility; and

2.2. The Utility has either:

2.2.1 Inspected the Generating Facility and has not found that the Generating Facility fails to comply with a Level 1 technical screen or a UL or IEEE standard; or

2.2.2 Waived its right to inspect the Generating Facility by not scheduling an inspection in the allotted time; or

Explicitly waived the right to inspect the Generating Facility.

3.0 Safe Operations and Maintenance
The Interconnection Customer shall be fully responsible to operate, maintain, and repair the Generating Facility as required to ensure that it complies at all times with IEEE Std 1547™.

4.0 Access
The Utility shall have access to the metering equipment of the Generating Facility at all times. The Utility shall provide reasonable notice to the Interconnection Customer when possible prior to using its right of access.

5.0 Disconnection
The Utility may temporarily disconnect the Generating Facility upon the following conditions:

5.1. For scheduled outages upon reasonable notice.

5.2. For unscheduled outages or emergency conditions.

5.3. If the Generating Facility does not operate in the manner consistent with these terms and conditions of the Agreement.

5.4. The Utility shall inform the Interconnection Customer in advance of any scheduled disconnection, or as soon as possible after an unscheduled disconnection.

6.0 Indemnification

Each Party shall at all times indemnify, defend, and hold the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the indemnified Party's action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7. 0 Insurance

The Interconnection Customer is not required to provide general liability insurance coverage as part of this Agreement, or through any other Utility requirement**.**

8.0 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 Termination

9.1. This Agreement may be terminated under the following conditions:

9.1.1 By the Interconnection Customer: By providing written notice to the Utility.

9.1.2 By the Utility: If the Generating Facility fails to operate for any consecutive 12- month period or the Interconnection Customer fails to remedy a violation of these terms and conditions of the Agreement.

9.2. Permanent Disconnection: In the event the Agreement is terminated, the Utility shall have the right to disconnect its facilities or direct the Interconnection Customer to disconnect its Generating Facility.

9.3. Survival Rights: This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 Assignment

For a Generating Facility offsetting part or all of the load of a utility customer at a given site, that customer is the Interconnection Customer and that customer may assign its Interconnection Agreement to a subsequent occupant of the site. For a Generating Facility providing energy directly to a Utility, the Interconnection Customer is the owner of the Generating Facility and may assign its Interconnection Agreement to a subsequent owner of the Generating Facility. Assignment is only effective after the assignee provides written notice of the assignment to the Utility and agrees to accept the Interconnection Customer's responsibilities under the Interconnection Agreement.

Attachment 4

Level 2, Level 3, and Level 4 Interconnection Application

This form should be made available in an electronically fillable format and it shall be permissible to submit the form with electronic signatures.

An Application is complete when it provides all applicable information required below and any required Application fee. A one-line diagram and a load flow data sheet must be supplied with this Application. Additional information to evaluate a request for interconnection may be required after an Application is deemed complete, however the Utility shall endeavor to identify data needs upfront rather than repeatedly asking for additional information.

Applicant requests review under (select one):

______ Level 2 _______ Level 3 ________ Level 4

Written Applications should be submitted by mail or e-mail to:

Utility: ____

Address: ____

E-Mail Address: ____

Utility Contact Name: ____

Utility Contact Title: ____

1. Applicant Information

Legal Name of Applicant (if an individual, individual's full name)

Name: ____

Address: ____

City, State, Zip: ____

Telephone (Day): ______________________ (Evening):__________________________

E-Mail Address: ______________________

Representative (if different)

Name: ____

Address: ____

City, State, Zip: ____

Telephone (Day): ______________________ (Evening):__________________________

E-Mail Address: ______________________

Type of interconnection (choose one): ______ Net Metering

______ Load Response (no export)

______ Wholesale Provider

Utility Account Number (for Generating Facilities at Utility customer locations): ___________[1]

2. Generating Facility Specifications

All power ratings should be listed in AC throughout.

Location (if different from above): ____

Facility Owner (include percent ownership by any electric utility): _______________________

____

Applicant Load: (kW) ____________ (if none, so state)

Typical Reactive Load (if known): __________________

Total number and type of generators to be interconnected pursuant to this Application: ________

____

Total number of inverters to be interconnected pursuant to this Application: ________________

Total Aggregate Nameplate Rating for all Generators: (kW) _________ (kVA)______________

Generating Capacity[2]: (kW) ________________ (kVA) ____________________

(a) Limited-Export / Non-Export / Limited-Import Data:

If multiple export control systems are used, provide for each control system and use additional sheets if needed.

Is export controlled to less than the Total Aggregate Nameplate Rating? Yes: ______ No: ____

Method of export limitation: Power Control System / Reverse Power Protection / Minimum Power Protection / Other (describe): _________________________________

Export controls are applied to how many generators? Multiple: _____ One: _____

If Power Control System is used, open loop response time: _______________ (s)

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[1] If the Utility requires the customer's name on the application to match the customer on the bill this should be specified on the application.

[2] As limited by any export controls.

Power Control System output limit setting: (kW) ___________ (kVA) ___________

Energy Storage System Power Control System operating mode:

Unrestricted: ________ Export Only: ________ Import Only: ________ No Exchange: _______

If relay is used to limit export, list relevant relay setpoints: ______________________________

____

Describe which Generators the export control system controls:___________________________

____

(b) Individual Generator Data:

Provide for each Generator, use additional sheets if needed.

Generator Technology: Photovoltaic / Turbine/ Fuel Cell / Energy Storage/ Other (describe): ___

____

Generator[3] Manufacturer, Model Name & Number: ____________________________________

Version Number: ____

Generator Nameplate Rating: ____

Energy Source: Solar / Wind / Hydro / Other (describe): ______________________________

If Energy Storage, usable capacity at maximum discharge rate: ____________________ (kWh)

(c) Individual Inverter Data (if any):

Provide for each inverter, use additional sheets if needed.

Inverter Manufacturer: ____

Model Name & Number: ____

Version Number:____

Nameplate Rating: (kW) (kVA) (AC Volts): _______________________________________

Rated Power Factor: (Underexcited) ________________ (Overexcited) _________________

Minimum Power Factor: (Underexcited) ______________ (Overexcited) _________________

Do export controls apply to this inverter? Yes:____________ No: ____________________

Single phase: _____ Three phase: _____ (check one)

List of adjustable set points for the protective equipment or software: _____________________

____

[3] E.g. the solar PV module manufacturer, battery manufacturer, etc. The inverter information is provided below.

Single Phase: __________ Three Phase: __________ (check one)

Max design fault contribution current (choose one): Instantaneous: ________ RMS: __________

Is the inverter UL1741 Listed? Yes: ______ No: ______

If Yes, attach evidence of UL1741 listing.

(d) Rotating Machines (of any type)

Manufacturer, Model Name & Number: ____

Version Number: ____

Nameplate Output Power Rating: (kW) _____________________ (kVA) _________________

Rated Power Factor: (Underexcited) _________________ (Overexcited) ___________________

Minimum Power Factor: (Underexcited) ______________ (Overexcited) ___________________

Single phase: _____ Three phase: _____ (check one)

List of adjustable set points for the protective equipment or software: _______________________

____

Do export controls apply to this machine? Yes:__________________ No:____________________

RPM Frequency: ____

Neutral Grounding Resistor (If Applicable): ____

List components of the Interconnection Equipment Package that are UL or IEEE Certified:

Equipment Type	Certifying Entity
1. ______________________________________	____________________________________
2. ______________________________________	____________________________________
3. ______________________________________	____________________________________
4. ______________________________________	____________________________________

Is the prime mover compatible with the Interconnection Equipment Package? ___ Yes ___ No

(e) Synchronous Generators

Direct Axis Synchronous Reactance, Xd:_______________ P.U.

Direct Axis Transient Reactance, X' d: ________________ P.U.

Direct Axis Subtransient Reactance, X" d: _____________ P.U.

Negative Sequence Reactance, X2: ___________________ P.U.

Zero Sequence Reactance, X0: ______________________ P.U.

KVA Base: ____

Field Volts: ____

Field Amperes: ______________________________________

For synchronous generators, provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

(f) Induction Generators

Motoring Power (kW): ______________________________

I^2t or K (Heating Time Constant): ____________________

Rotor Resistance, Rr: ___________________ Rotor Reactance, Xr: __________________

Stator Resistance, Rs: ___________________ Stator Reactance, Xs: _________________

Magnetizing Reactance, Xm: _________________________

Short Circuit Reactance, Xd: _________________________

Exciting Current: ___________________________________

Temperature Rise: __________________________________

Frame Size: ____

Design Letter: ______________________________________

Reactive Power Required In Vars (No Load): ________________________

Reactive Power Required In Vars (Full Load): _______________________

Total Rotating Inertia, H: ______________________ Per Unit on kVA Base

3. Transformer and Protective Relay Specifications

Will a transformer be used between the generator and the Point of Common Coupling?

______ Yes ______ No

Will the transformer be provided by the Interconnection Customer? ______ Yes ______ No

(a) Transformer Data: (if applicable, for Interconnection Customer-Owned Transformer)

Is the transformer: _____ single phase ______ three phase (check one) Size: ________ kVA

Transformer Impedance: ____ percent on _________ kVA Base

If Three Phase:

Transformer Primary: _____ Volts _____ Delta _____ Wye _____ Wye Grounded

Transformer Secondary: _____ Volts _____ Delta _____ Wye _____ Wye Grounded

Transformer Tertiary: _____ Volts _____ Delta _____ Wye _____ Wye Grounded

(b) Transformer Fuse Data: (if applicable, for Interconnection Customer-Owned Fuse)

(Enclose/Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: ___________________ Type: _____________ Size: ________Speed: ________

(c) Interconnecting Circuit Breaker: (if applicable)

Manufacturer: _________________________ Type: ________________________________

Load Rating (Amps): _______ Interrupting Rating (Amps): ______ Trip Speed (Cycles): ____

(d) Interconnection Protective Relays: (if applicable)

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.	______________________	______________________	______________________
2.	______________________	______________________	______________________
3.	______________________	______________________	______________________

(e) Discrete Components: (if applicable)

(Enclose/Attach Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: ______________________ Type: _____________ Style/Catalog No.: ______

Proposed Setting: ____________________________

Manufacturer: ______________________ Type: _____________ Style/Catalog No.: ______

Proposed Setting: ____________________________

Manufacturer: ______________________ Type: _____________ Style/Catalog No.: ______

Proposed Setting: ____________________________

(f) Current Transformer Data: (if applicable)

(Enclose/Attach Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ____

Type: _____________ Accuracy Class: __________ Proposed Ratio Connection: _____

(g) Potential Transformer Data: (if applicable)

Manufacturer: ____

Type: _____________ Accuracy Class: __________ Proposed Ratio Connection: _____

4. General Information

Enclose/Attach copy of site electrical one-line diagram showing the configuration of all Generating Facility equipment, current and potential circuits, and protection and control schemes.[4] This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Generating Facility is larger than 200 kW.

Is one-line diagram enclosed? _____ Yes _____ No

Enclose/Attach copy of any site documentation that indicates the precise physical location of the proposed Generating Facility and all protective equipment (e.g., USGS topographic map or other diagram or documentation).

Is site documentation enclosed? _____ Yes _____ No

Enclose/Attach copy of any site documentation that describes and details the operation of the protection and control schemes.

Is available documentation enclosed? _____ Yes _____ No

Enclose/Attach copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).

Are schematic drawings enclosed? _____ Yes _____ No

5. Applicant Signature (may be electronic)

I designate the individual or company listed as my Representative to serve as my agent for the purpose of coordinating with the Utility on my behalf through the interconnection process (*see* Interconnection Procedures Section IV.F.13). INITIAL: __________

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Application is true and correct. I also agree to install a warning label provided by (utility) on or near my service meter location. Generating Facilities must be compliant with IEEE, NEC, ANSI, and UL standards, where applicable. By signing below, the Applicant also

[4] Some states require or encourage utilities to publish sample one-line diagrams that illustrate the expectations for format and detail. Such supporting materials can help the customer and the utility by reducing the number of applications that are deemed incomplete on the first try.

certifies that the installed generating equipment meets the appropriate preceding requirement(s) and can supply documentation that confirms compliance.

Signature of Applicant: ______________________________________

Date: ____

6. Information Required Prior to Physical Interconnection

A Certificate of Completion in the form of Attachment 6 of the Interconnection Procedures must be provided to the Utility prior to interconnected operation. The Certificate of Completion must either be signed by an electrical inspector with the authority to approve the interconnection or be accompanied by the electrical inspector's own form authorizing interconnection of the Generating Facility.

Attachment 5

Level 2, Level 3, and Level 4 Interconnection Agreement

(Standard Agreement for interconnection of Generating Facilities)

This agreement ("Agreement") is made and entered into this _____ day of ___________, _____ ("Effective Date") by and between ____________________, a _____________ organized and existing under the laws of the State of _______________, ("Interconnection Customer") and _____________________, a __________________, existing under the laws of the State of ___________________, ("Utility"). Interconnection Customer and Utility each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, Interconnection Customer, as an Applicant, is proposing to develop a Generating Facility, or Generating Capacity addition to an existing Generating Facility, consistent with the Application completed by Interconnection Customer on _______________; and

Whereas, Interconnection Customer desires to interconnect the Generating Facility with the Utility's Electric Delivery System;

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 This Agreement shall be used for all approved Level 2, Level 3, and Level 4 Interconnection Applications according to the procedures set forth in the Interconnection Procedures. Capitalized terms in this Agreement if not defined in the Agreement have the meanings set forth in the Interconnection Procedures.

1.2 This Agreement governs the terms and conditions under which the Generating Facility will interconnect to, and operate in parallel with, the Utility's Electric Delivery System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power.

1.4 Nothing in this Agreement is intended to affect any other agreement between Utility and Interconnection Customer. However, in the event that the provisions of this Agreement are in conflict with the provisions of a Utility tariff, the Utility tariff shall control.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all applicable laws and regulations, and operating requirements.

1.5.2 The Interconnection Customer shall construct and operate the Generating Facility in the manner specified in the Application. If design or operational changes are made, and agreed upon by the Utility, during the interconnection review process those shall be specified in an Exhibit to this Agreement.

1.5.3 The Interconnection Customer shall arrange for the construction, interconnection, operation and maintenance of the Generating Facility in accordance with the applicable manufacturer's recommended maintenance schedule, in accordance with this Agreement.

1.5.4 The Utility shall construct, own, operate, and maintain its Electric Delivery System and its facilities for interconnection ("Interconnection Facilities") in accordance with this Agreement.

1.5.5 The Interconnection Customer agrees to arrange for the construction of the Generating Facility or systems in accordance with applicable specifications that meet or exceed the National Electrical Code, the American National Standards Institute, IEEE, UL, and any operating requirements.

1.5.6 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Exhibits to this Agreement and shall do so in a manner so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the other Party.

1.5.7 Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the Point of Common Coupling.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection
The Interconnection Customer shall arrange for the testing and inspection of the Generating Facility prior to interconnection in accordance with IEEE Std 1547™ and the Interconnection Procedures.

2.2 Certificate of Completion
Prior to commencing parallel operation, the Interconnection Customer shall provide the Utility with a Certificate of Completion substantially in the form of

Attachment 6 of the Interconnection Procedures. The Certificate of Completion must either be signed by an electrical inspector with the authority to approve the interconnection or be accompanied by the electrical inspector's own form authorizing interconnection of the Generating Facility.

2.3 Authorization
The Interconnection Customer is authorized to commence parallel operation of the Generating Facility when there are no contingencies noted in this Agreement remaining.

2.4 Parallel Operation Obligations
The Interconnection Customer shall abide by all permissible written rules and procedures developed by the Utility which pertain to the parallel operation of the Generating Facility. In the event of conflicting provisions, the Interconnection Procedures shall take precedence over a Utility's rule or procedure, unless such Utility rule or procedure is contained in an approved tariff, in which case the provisions of the tariff shall apply. Copies of the Utility's rules and procedures for parallel operation are either provided as an exhibit to this Agreement or in an exhibit that provides reference to a website with such material.

2.5 Reactive Power
The Interconnection Customer shall design its Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Common Coupling at a power factor within the range of 0.95 absorbing to 0.95 injecting.

2.6 Right of Access
At reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Utility shall have reasonable access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on the Utility under this Agreement, or as is necessary to meet a legal obligation to provide service to customers.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date
This Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement
This Agreement shall remain in effect unless terminated earlier in accordance with Article 3.3 of this Agreement.

3.3 Termination
No termination shall become effective until the Parties have complied with all applicable laws and regulations applicable to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Utility twenty (20) Business Days' written notice.

3.3.2 Either Party may terminate this Agreement pursuant to Article 6.6.

3.3.3 Upon termination of this Agreement, the Generating Facility will be disconnected from the Electric Delivery System. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.4 The provisions of this Article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

The Utility may temporarily disconnect the Generating Facility from the Electric Delivery System for so long as reasonably necessary in the event one or more of the following conditions or events:

3.4.1 Emergency Conditions: "Emergency Condition" shall mean a condition or situation:

(1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or

(2) that, in the case of Utility, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of the Utility's Interconnection Facilities or damage to the Electric Delivery System; or

(3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility.

Under emergency conditions, the Utility or the Interconnection Customer may immediately suspend interconnection service and temporarily disconnect the Generating Facility. The Utility shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Generating Facility. The Interconnection Customer shall notify the Utility promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Utility's Electric Delivery System. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and any necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair: The Utility may interrupt interconnection service or curtail the output of the Generating Facility and temporarily disconnect the Generating Facility from the Electric Delivery System when necessary for routine maintenance, construction, and repairs on the Electric Delivery System. The Utility shall provide the Interconnection Customer with five (5) Business Days notice prior to such interruption. The Utility shall use reasonable efforts to coordinate such repair or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages: During any forced outage, the Utility may suspend interconnection service to effect immediate repairs on the Electric Delivery System. The Utility shall use reasonable efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects: The Utility shall provide the Interconnection Customer with a written notice of its intention to disconnect the Generating Facility if, based on good utility practice, the Utility determines that operation of the Generating Facility will likely cause unreasonable disruption or deterioration of service to other Utility customers served from the same electric system, or if operating the Generating Facility could cause damage to the Electric Delivery System. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. The Utility may disconnect the Generating Facility if, after receipt of the notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time which shall be at least five (5) Business Days from the date the Interconnection Customer receives the Utility's written notice supporting the decision to disconnect, unless emergency conditions exist in which case the provisions of Article 3.4.1 apply.

3.4.5 Modification of the Generating Facility: The Interconnection Customer must receive written authorization from Utility before making any change to the Generating Facility that may have a material impact on the safety or reliability of the Electric Delivery System. Such authorization shall not be unreasonably withheld. Modifications shall be completed in accordance with good utility practice. Requests for modification and approval of such requests shall be made in accordance with Section I.C.4 of the Interconnection Procedures. If the Interconnection Customer makes such modification without the Utility's prior written authorization, the latter shall have the right to temporarily disconnect the Generating Facility.

3.4.6 Reconnection: The Parties shall cooperate with each other to restore the Generating Facility, Interconnection Facilities, and the Electric Delivery System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the interconnection facilities itemized in the Exhibits to this Agreement ("Interconnection Facilities"). If a Facilities Study was performed, the Utility shall identify its Interconnection Facilities necessary to safely interconnect the Generating Facility with the Electric Delivery System, the cost of those facilities, and the time required to build and install those facilities.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its Interconnection Equipment Package, and (2) operating, maintaining, repairing, and replacing the Utility's Interconnection Facilities as set forth in any exhibits to this Agreement.

4.2 Distribution Upgrades

The Utility shall design, procure, construct, install, and own any Electric Delivery System upgrades ("Utility Upgrades"). The actual cost of the Utility Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Billing, Payment, Milestones, and Financial Security

5.1 Billing and Payment Procedures and Final Accounting

5.1.1 The Utility shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of the Utility provided Interconnection Facilities and Utility Upgrades contemplated by this Agreement as set forth in the exhibits to this Agreement, on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within thirty (30) calendar days of receipt, or as otherwise agreed by the Parties.

5.1.2 Within sixty (60) Calendar Days of completing the construction and installation of the Utility's Interconnection Facilities and Utility Upgrades described in the exhibits to this Agreement, the Utility shall provide the Interconnection Customer with a final accounting report of any difference between (1) the actual cost incurred to complete the construction and installation and the budget estimate provided to the Interconnection

Customer and (2) the Interconnection Customer's previous deposit and aggregate payments to the Utility for such Interconnection Facilities and Utility Upgrades. The Utility shall provide a written explanation for any actual cost exceeding a budget estimate by 25 percent or more. If the Interconnection Customer's cost responsibility exceeds its previous deposit and aggregate payments, the Utility shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Utility within thirty (30) calendar days. If the Interconnection Customer's previous deposit and aggregate payments exceed its cost responsibility under this Agreement, the Utility shall refund to the Interconnection Customer an amount equal to the difference within thirty (30) Business Days of the final accounting report.

5.2 Interconnection Customer Deposit

At least twenty (20) Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Utility's Interconnection Facilities and Utility Upgrades, the Interconnection Customer shall provide the Utility with a deposit equal to 50 percent of the cost estimated for its Interconnection Facilities prior to its beginning design of such facilities.

Article 6. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

6.1 Assignment

This Agreement may be assigned by either Party as provided below upon fifteen (15) Business Days' prior written notice to the other Party.

6.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement.

6.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Utility, for collateral security purposes to aid in providing financing for the Generating Facility.

6.1.3 For a Generating Facility offsetting part or all of the load of a utility customer at a given site, that customer is the Interconnection Customer and that customer may assign its Interconnection Agreement to a subsequent occupant of the site. For a Generating Facility providing energy directly to a Utility, the Interconnection Customer is the owner of the Generating Facility and may assign its Interconnection Agreement to a subsequent owner of the Generating Facility. Assignment is only effective after the assignee provides written notice of the assignment to the Utility and agrees to accept the Interconnection Customer's responsibilities under this Interconnection Agreement.

6.1.4 All other assignments shall require the prior written consent of the non-assigning Party, such consent not to be unreasonably withheld.

6.1.5 Any attempted assignment that violates this Article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same obligations as the Interconnection Customer.

6.2 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages, except as specifically authorized by this Agreement.

6.3 Indemnity

6.3.1 This provision protects each Party from liability incurred to third Parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 6.2.

6.3.2 Each Party shall at all times indemnify, defend, and hold the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the indemnified Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

6.3.3 If an indemnified Party is entitled to indemnification under this Article as a result of a claim by a third party, the indemnifying Party shall, after reasonable notice from the indemnified Party, assume the deference of such claim. If the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such claim, the indemnified Party may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

6.3.4 If the indemnifying Party is obligated to indemnify and hold the indemnified Party harmless under this Article, the amount owing to the indemnified Party shall be the amount of such indemnified Party's actual loss, net of any insurance or other recovery.

6.3.5 Promptly after receipt of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified Party shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

6.4 Consequential Damages

Neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

6.5 Force Majeure

6.5.1 As used in this Article, a Force Majeure Event shall mean any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

6.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event ("Affected Party") shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance, and if the initial notification was verbal, it should be promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated by the Affected Party. The Affected Party shall use reasonable efforts to resume its performance as soon as possible.

6.6 Default

6.6.1 Default exists where a Party has materially breached any provision of this Agreement, except that no default shall exist where a failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement, or the result of an act or omission of the other Party.

6.6.2 Upon a default, the non-defaulting Party shall give written notice of such default to the defaulting Party. Except as provided in Article 6.6.3, the defaulting Party shall have 60 calendar days from receipt of the default notice within which to cure such default; provided however, if such default is not capable of cure within 60 calendar days, the defaulting Party shall commence efforts to cure within 20 calendar days after notice and continuously and diligently pursue such cure within six months from receipt of the default notice; and, if cured within such time, the default specified in such notice shall cease to exist.

6.6.3 If a default is not cured as provided in this Article, or if a default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this Article will survive termination of this Agreement.

Article 7. Insurance

The Interconnection Customer is not required to provide insurance coverage for utility damages beyond the amounts listed in Section IV.F.6 of the Interconnection Procedures as part of this Agreement, nor is the Interconnection Customer required to carry general liability insurance as part of this Agreement or any other Utility requirement. It is, however, recommended that the Interconnection Customer protect itself with liability insurance.

Article 8. Dispute Resolution

Any dispute arising from or under the terms of this Agreement shall be subject to the dispute resolution procedures contained in the Interconnection Procedures.

Article 9. Miscellaneous

9.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of ____________________, without regard to its conflicts of law principles (*if left blank, such state shall be the state in which the Generating Facility is located*). This Agreement is subject to all applicable laws and regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a governmental authority.

9.2 Amendment
The Parties may only amend this Agreement by a written instrument duly executed by both Parties.

9.3 No Third-Party Beneficiaries
This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest, and, where permitted, their assigns.

9.4 Waiver

9.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

9.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any failure to comply with any other obligation, right, or duty of this Agreement. Termination or default of this Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

9.5 Entire Agreement
This Agreement, including all exhibits, constitutes the entire Agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

9.6 Multiple Counterparts
This Agreement may be executed in two or more counterparts, each of which is deemed an original but all of which constitute one and the same Agreement.

9.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties nor to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

9.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore, insofar as practicable, the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

9.9 Environmental Releases

Each Party shall notify the other Party, first orally and then in writing, of the release any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any governmental authorities addressing such events.

9.10 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain liable for the performance of such subcontractor.

9.10.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having Application to, any subcontractor of such Party.

9.10.2 The obligations under this Article will not be limited in any way by any limitation of subcontractor's insurance.

Article 10. Notices

10.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

Interconnection Customer:

____

Attention: _______________________________________

Address: ____

City: ______________________________ State: _______ Zip: ________

Phone: ______________________________

Email: ______________________________

Utility:

Attention: _______________________________________

Address: ____

City: ______________________________ State: _______ Zip: ________

Phone: ______________________________

Email: ______________________________

10.2 Billing and Payment

Billings and payments to Interconnection Customer shall be sent to the address provided in Section 10.1 unless an alternative address is provided here:

Interconnection Customer:

____

Attention: ____

Address: ____

City: ________________________________ State: _______ Zip: ________

Phone: ______________________________

Email: _______________________________

10.3 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement (*see* Interconnection Procedures Section IV.F.13). This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's operating representative:

____

Attention: ____

Address: ____

City: ________________________________ State: _______ Zip: ________

Phone: ______________________________

Email: _______________________________

Utility's operating representative:

Attention: ____

Address: ____

City: ________________________________ State: _______ Zip: ________

Phone: ______________________________

Email: _______________________________

Article 11. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Utility:

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

For the Interconnection Customer:

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Exhibits incorporated in this Agreement: *May include:*

a) one-line diagram and site maps

b) Interconnection Facilities to be constructed by the Utility. The interconnection facilities exhibit shall include any milestones for both the Interconnection Customer and the Utility as well as cost responsibility and apportionments if there is more than one Generating Facility interconnecting and sharing in the Distribution Upgrade costs;

c) operational requirements or reference to Utility website with these requirements – this exhibit shall require the Interconnection Customer to operate within the bounds of IEEE Std 1547™ and associated standards;

d) reimbursement of costs (Utility may, in its sole discretion, reimburse Interconnection Customer for Utility Upgrades that benefit future Generating Facilities);

e) operating restrictions (no operating restrictions generally apply to Levels 1, 2 or 3 interconnections but may apply, in the discretion of the Utility, to Generating Facilities approved under Level 4. Design or operating changes or limitations that are different from the application should be identified);

f) copies of, Impact and Facilities Study agreements.

Attachment 6

Certification of Completion

Installation Information Check if owner-installed ☐

Applicant: ________________________Contact Person:_____________________________
Mailing Address: ____
Location of Generating Facility (if different from above): _____________________________
City: ______________________________ State: _________________ Zip Code: _______
Telephone (Daytime): _________________ (Evening): _____________________________
E-Mail Address: _________________________

Electrician:

Installing Electrician: _ ____ Firm: _________________________

License No.: ____
Mailing Address: _ ____
____

City: _ _________________________________ State: ____________ Zip Code: ____________

Telephone (Daytime): _________________ (Evening): _____________________________
E-Mail Address: _____________________

Installation Date: _______ Interconnection Date: ____________________

Electrical Inspection:

The system has been installed and inspected in compliance with the local Building/Electrical Code of ____________________________ (appropriate governmental authority).

Local Electrical Wiring Inspector (***or attach signed electrical inspector's form***):

Signature: _____________________________________
Name (printed): __________________________________ Date: __________________

The electrical inspector's form may be used in place of this form, so long as it contains substantively the same information and approval.

Attachment 7

System Impact and Facilities Study Agreements

As noted in the Interconnection Procedures, a Utility may require that a proposed Level 4 Generating Facility be subject to System Impact and Facilities Studies. At the Utility's discretion, any of these studies may be combined or foregone. Also, at the Utility's discretion, for any study, the Applicant may be required to provide information beyond the contents of the Application; but, the Utility shall endeavor to request all information upfront to the greatest extent possible. Sample study agreements are provided on the following pages.

Attachment 7A

System Impact Study Agreement

This agreement ("Agreement") is made and entered into this _________ day of ____________ by and between ______________________________, a_______________________ organized and existing under the laws of the State of_________________________, ("Applicant,") and _________________________________, a _________________________ existing under the laws of the State of _____________________________, ("Utility"). The Applicant and the Utility each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, Applicant is proposing to develop a Generating Facility or Generating Capacity addition to an existing Generating Facility consistent with the Application completed by Applicant on and;

Whereas, Applicant desires to interconnect the Generating Facility with the Utility's Electric Delivery System;

Whereas, Applicant has requested the Utility perform a System Impact Study to assess the impact of interconnecting the Generating Facility to the Utility's Electric Delivery System;

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement, Capitalized terms shall have the meanings indicated. Capitalized terms not defined in this Agreement shall have the meanings specified in the Interconnection Procedures.
2. Applicant elects and the Utility shall cause to be performed a System Impact Study consistent with Section III.F.4 of the Interconnection Procedures.
3. The scope of the System Impact Study shall be based on information supplied in the Application, any prior study of the Generating Facility completed by the Utility, and any other information or assumptions set forth in any attachment to this Agreement.
4. The Utility reserves the right to request additional technical information from Applicant as may reasonably become necessary consistent with good utility practice during the course of the System Impact Study. If after signing this Agreement, Applicant modifies its Application or any of the information or assumptions in any attachment to this Agreement, the time to complete the System Impact Study may be extended.
5. The System Impact Study shall provide the following information:
    - 5.1. Identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection,
    - 5.2. Identification of any thermal overload or voltage limit violations resulting from the interconnection,
    - 5.3. Identification of any instability or inadequately damped response to system disturbances resulting from the interconnection and
    - 5.4. Description and non-binding, good faith estimated cost of facilities required to interconnect the Generating Facility to the Electric Delivery System and to address the identified short circuit, instability, and power flow issues.

6. The Utility may require a study deposit of the lesser of 50 percent of estimated non-binding good faith study costs or $3,000. If required, this shall be provided by the Applicant at the time it returns this Agreement.
7. The System Impact Study shall be completed and the results transmitted to Applicant within forty (40) Business Days after this Agreement is signed by the Parties, unless the proposed Generating Facility will impact other proposed generating facilities.
8. Study fees shall be based on actual costs and will be invoiced to Applicant after the study is transmitted to Applicant. The invoice shall include an itemized listing of employee time and costs expended on the study.
9. Applicant shall pay any actual study costs that exceed the deposit without interest within thirty (30) calendar days on receipt of the invoice. The Utility shall refund any excess amount without interest within thirty (30) calendar days of the invoice.

In witness thereof, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

For the Utility

Signature: ______________________________ Date: ____________

Printed Name: ______________________________

Title: ______________________________

Date: ____________

For the Applicant

Signature: ______________________________ Date: ____________

Printed Name: ______________________________

Title: ______________________________

Are attachments included to supplement or modify information contained in the Application?

_______ Yes ______ No

Attachment 7B

Interconnection Facilities Study Agreement

This agreement ("Agreement") is made and entered into this _________ day of _______________ by and between ______________________________, a _______________________ organized and existing under the laws of the State of _________________________, ("Applicant,") and _________________________________, a __________________________existing under the laws of the State of _____________________________, ("Utility"). The Applicant and the Utility each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, Applicant is proposing to develop a Generating Facility or Generating Capacity addition to an existing Generating Facility consistent with the Application completed by Applicant; and

Whereas, Applicant desires to interconnect the Generating Facility with the Utility's Electric Delivery System;

Whereas, the Utility has completed or waived an System Impact Study and provided the results of said studies to Applicant; and

Whereas, Applicant has requested that Utility perform a Facilities Study to specify and estimate the cost of the engineering, procurement and construction work needed to physically and electrically connect the Generating Facility to the Electric Delivery System in accordance with good utility practice.

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this agreement, capitalized terms shall have the meanings indicated. Capitalized terms not defined in this agreement shall have the meanings specified in the Interconnection Procedures.
2. Applicant elects and the Utility shall cause to be performed a Facilities Study consistent with Section III.F.5 of the Interconnection Procedures.
3. The scope of the Facilities Study shall be subject to information supplied in the Application, and any feasibility study or System Impact Study performed by the Utility for the Generating Facility and any other information or assumptions set forth in any attachment to this agreement.
4. The Utility reserves the right to request additional technical information from Applicant as may reasonably become necessary consistent with good utility practice during the course of the Facilities Study.
5. A Facilities Study report (1) shall provide a detailed and itemized description of all required facilities to interconnect the Generating Facility to the Electric Delivery System, the estimated costs of those facilities, and schedule for their construction and (2) shall address the short circuit, instability, and power flow issues identified in the System Impact Study.
6. The Utility may require a study deposit of the lesser of 50 percent of estimated non-binding good faith study costs or $5,000. If required, this shall be provided by the Applicant at the time it returns this Agreement.

7. The Facilities Study shall be completed and the results shall be transmitted to Applicant within sixty (60) Business Days after this agreement is signed by the Parties.
8. Study fees shall be based on actual costs and will be invoiced to Applicant after the study is transmitted to Applicant. The invoice shall include an itemized listing of employee time and costs expended on the study.
9. Applicant shall pay any actual study costs that exceed the deposit without interest within thirty (30) calendar days on receipt of the invoice. The Utility shall refund any excess amount without interest within thirty (30) calendar days of the invoice.

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

For the Utility

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Date: ____________________

For the Applicant

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Are attachments included to supplement or modify information contained in the Application and the System Impact Study (if performed)?

_______ Yes ______ No

Attachment 8

Public Queue Requirements

Each utility shall maintain a public interconnection queue, pursuant to Interconnection Procedures Section I.C.3, available in a sortable spreadsheet format on its website, which it shall update on at least a monthly basis. The date of the most recent update shall be clearly indicated.

The public queue should include, at a minimum, the following information about each interconnection application.

1. Queue number
2. Facility capacity (kW)
3. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
4. Secondary fuel type (if applicable)
5. Exporting or Non-Exporting
6. City
7. Zip code
8. Substation
9. Feeder
10. Status (active, withdrawn, interconnected, etc.)
11. Date application deemed complete
12. Date of notification of Level 2 screen results, for projects undergoing review under Levels 1, 2, or 3 (if applicable)
13. Level 2 Screen results, for projects undergoing review under Levels 1, 2, or 3 (pass or fail, and if fail, identify the screens failed)
14. Date of notification of Supplemental Review results (if applicable)
15. Supplemental Review Results (pass or fail, and if fail, identify the screens failed)
16. Date of notification of System Impact Study results (if applicable)
17. Date of notification of Facilities Study results and/or construction estimates (if applicable)

18. Date final Interconnection Agreement is provided to Customer

19. Date Interconnection Agreement is signed by both parties

20. Date of grant of permission to operate

21. Final interconnection cost paid to utility

Attachment 9

Reporting Requirements

Each Utility shall submit to the Commission make available to the public on its website an interconnection report the following information, as required by Section IV.D. The report shall contain information in the following areas, including relevant totals for both the year and the most recent reporting period.

1. Pre-Application Reports
   a. Total number of reports requested
   b. Total number of reports in process
   c. Total number of reports issued
   d. Total number of requests withdrawn
   e. Maximum, mean, and median processing times from receipt of request to issuance of report
   f. Number of reports processed in more than the ten (10) Business Days allowed in Section II.B.1

2. Interconnection Applications:

   a. Total number received, broken down by:
      i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
      ii. System size (e.g., <20 kW, <1 MW, <5MW, >5MW)

   b. Level 1 Review Process
      i. Total number of applications processed
      ii. Maximum, mean, and median processing times from receipt of complete Application to provision of counter-signed Interconnection Agreement

   c. Level 2 Review Process
      i. Total number of applications that passed the screens in Section III.B.2
      ii. Total number of applications that failed the screens in Section III.B.2[1]
      Maximum, mean, and median processing times from receipt of complete Application to issuance of Interconnection Agreement

[1] If the specific screens failed are not tracked in the public queue, or a queue is not published for smaller projects, then the utilities should be required to report on the number of projects that are failing each screen and in what size categories. Failure of specific screens is an important indication of whether penetrations are reaching high levels or whether other issues exist that may require a broader policy or technical solution.

d. Level 3 Review Process
   i. Total number of applications that passed the screens in Section III.B.2
   ii. Total number of applications that failed the screens in Section III.B.2
   iii. Maximum, mean, and median processing times from receipt of complete Application to issuance of Interconnection Agreement

e. Supplemental Review
   i. Total number of applications that passed the screens in Section III.D.1
   ii. Total number of applications that failed the screens in Section III.D.1
   iii. Maximum, mean, and median processing times from receipt of complete Application to issuance of Interconnection Agreement

f. Level 4 Review Process
   i. System Impact Studies
   ii. Total number of System Impact Studies completed under Section III.F.4
   iii. Maximum, mean, and median processing times from receipt of signed Interconnection System Impact Study Agreement to provision of study results

g. Facilities Studies
   i. Total number of Facilities Studies completed under Section III.F.5
   ii. Maximum, mean, and median processing times from receipt of signed Interconnection Facilities Study Agreement to provision of study results
   iii. Maximum, mean, and median processing times for projects undergoing the study process from receipt of complete Application to issuance of Interconnection Agreement

h. Construction: Number of projects where final construction milestone was not reached by time specified in the Interconnection Agreement

i. Number of Projects that achieved Commercial Operation, by:
   i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
   ii. System size (e.g., <20 kW, <1 MW, <5MW, >5MW)

IREC

EXHIBIT 2

Priority Considerations for INTERCONNECTION STANDARDS:

A Quick Reference Guide for Utility Regulators

IREC

Interstate Renewable Energy Council

August 2017

Priority Considerations for **INTERCONNECTION STANDARDS:**

A Quick Reference Guide for Utility Regulators

The power grid is much like our network of country roads, highways and freeways, carrying energy from its origin to its final destination. Interconnection standards are, in effect, the "rules of the road," set by policymakers, which both system owners and utilities must follow to keep traffic flowing smoothly. The quality of these rules—like any given street sign, traffic direction or roadmap—can facilitate an easy free-flow of traffic, or result in unnecessary gridlock. As we introduce new technologies and services, the rules must evolve.

At a basic level, interconnection standards should outline with clarity the timelines, fees, technical requirements and steps in the review process for connecting distributed energy resources—such as a solar PV system or an energy storage system—to the electricity grid. Ideally, the process to interconnect should not be an obstacle or a source of frustration and contention for any party involved in the process. Clear, forward-thinking rules are essential to maintain the safety and reliability of the grid, while also enabling the adoption of distributed energy resources and achieving broader clean energy and resiliency goals.

As an active participant at the Federal Energy Regulatory Commission (FERC) and in dozens of state commission rulemakings over the past decade, the Interstate Renewable Energy Council (IREC) has identified and synthesized the best practices in use across the country in our *Model Interconnection Procedures*, which is a free resource available to states for reference as work to develop and/or refine their own rules. IREC's aim with these model procedures is to streamline the regulatory process, save states' resources, and avoid the need to reinvent the wheel on interconnection.

This document is intended to serve as a supplement to IREC's Model Rules and provides a list of key interconnection considerations for states working to improve/update interconnection procedures. Each section offers a description of the key components to interconnection based upon established and well-vetted national best practices. In each case, we provided links to the most relevant examples, though other examples do exist in most cases.

For more information and to download other resources, please visit our website at www.irecusa.org.

Table of Contents

I. Project Applicability and Review Processes for Interconnection Applications

A. Applicability to All Projects

Some state procedures have been drafted so that they are applicable to projects only below a certain size threshold. This limitation means that some state jurisdictional projects may have no clear pathway to obtain an interconnection agreement since jurisdictional considerations, and not necessarily size, dictate whether a project must interconnect pursuant to state or federal interconnection procedures. This determination may correlate to some degree with size, since the state-jurisdictional distribution system uses lower voltage lines that can typically only accommodate projects up to a certain size (e.g., 20 MW). Nonetheless, the decision between state versus federal procedures ultimately comes down to application of jurisdictional rules related to the sale of the power. Therefore, it is not necessary or advisable to apply a size limit to state-jurisdictional procedures. For example, a project may exceed the established size limit on state procedures but still need to obtain a state-jurisdictional interconnection agreement, and in that case, it would not be clear what process the project proponent should go through to obtain an interconnection agreement. Instead, IREC recommends removing the size limit restriction on determining applicability of the procedures and let application depend solely on jurisdictional considerations. The study process traditionally used within most state procedures is generally robust enough to handle projects of any size, though the terms in an interconnection agreement may need to be modified to accommodate larger projects.

“. . . interconnection procedures should specifically indicate that they cover energy storage, and may also want to consider steps to help ensure an efficient review process that recognizes the capabilities of energy storage systems.”

- IREC’s *Model Interconnection Procedures* are applicable to all state-jurisdictional interconnections (see Section I.A).
- The FERC SGIP applies to projects up to 20 MW (see Section 1.1.1). Larger projects would proceed under the Large Generator Interconnection Procedures (though some ISOs have eliminated this distinction). Unlike FERC, most states do not have separate procedures for large and small systems, so such a size cap is not necessarily relevant at the state level.

B. Inclusion of Energy Storage

As energy storage prices continue drop, it will become increasingly attractive for customer to consider installing energy storage systems, either with or without on-site generation systems (such as solar PV). Future policies, incentives and/or tariffs may further facilitate the adoption of energy storage, which is poised to offer a range of benefits to customers directly as well as their utilities. From an interconnection perspective, energy storage can mostly be treated the same as other generation technologies, however for the sake of clarity and transparency, the interconnection procedures should specifically indicate that they cover energy storage, and may also want to consider steps to help ensure an efficient review process that recognizes the capabilities of energy storage systems.

- In its Glossary of Terms in Attachment 1 (see Small Generator Interconnection Agreement (SGIA), Attachment 1) the FERC SGIP explicitly incorporates energy storage by defining “Small Generator Facility” to include devices for the production and/or storage for later injection of electricity. It also allows the utility to not always study the absolute maximum capacity if the applicant demonstrates the system will not be operated in that manner.

- IREC's recent papers, *Deploying Distributed Energy Storage: Near-Term Regulatory Considerations to Maximize Benefits* (Feb. 2015) and *Charging Ahead: An Energy Storage Guide for Policymakers* (April 2017) address some considerations regarding the interconnection of energy storage.
- California's Rule 21 Order (issued June 23, 2016) adopted an approach for how both the charging and discharging functions of energy storage systems should be reviewed. The adopted approach ensures that the load from energy storage systems is not treated differently from other types of customer load when it comes to assigning costs for review and upgrades.

C. Size Limit for Small, Inverter-based System Review, Also Known as "Level 1" Review

The expedited review process for small, inverter-based systems (e.g., solar PV and storage) is intended to allow for a streamlined process for generators that are unlikely to trigger adverse system impacts. This process requires similar, if not identical, technical screening to the Fast Track process (discussed below) but, unlike Fast Track, allows applicants to submit a relatively short, combined application and interconnection agreement. Doing so reduces the time and cost associated with the process for both applicants and utilities, and typically this savings is reflected in the lower fee charged for such applications. Historically, many states allowed systems up to 10 kW to participate in this expedited process because 10 kW reflected the upper limit for most net-metered residential solar PV systems. In recent years, states have begun to raise the eligibility size limit to 25 kW or above in recognition that systems larger than 10 kW may participate in net metering, and systems up to 25 kW are unlikely to cause adverse system impacts and thus can be safely connected with a simple screening process.

- IREC's *Model Interconnection Procedures* permit inverter-based generators up to 25 kW to undergo Level 1 review (see Section III.A.2.a).
- NREL's *Updating Small Generator Interconnection Procedures for New Market Conditions* explains the expedited small, inverter-based system review process and provides the rationales for increasing its size limit to 25 kW (see pp. 15-16).
- Some other states that have size limits that are greater than 10 kW include North Carolina, Ohio, Oregon, Utah and Massachusetts.

D. Size Limit for Fast Track Review, Also Known as "Level 2" Review

The Fast Track process consists of several technical screens intended to easily identify proposed interconnections that will not threaten the safety and reliability of the electric system, and allow these systems to proceed through an expedited review process. Although the technical screens decide whether a project will be able to interconnect without a full study, an overall size limit for Fast

Track eligibility offers applicants a useful indicator as to whether or not their system is at all likely to pass those screens and serves an administrative function for utilities to help sort projects into the proper study track. In the former iteration of the FERC SGIP and in many states' procedures, Fast Track review is limited to systems up to 2 MW. More recently, FERC and several states have moved away from a broadly applicable cap to a more nuanced, table-based approach, which takes into account location-related factors that affect the likelihood of the generator to have adverse impacts on the electric system. Specifically, the table-based approach allows the size limit to increase as the voltage of the line increases and if a generator is closer to the substation. As with the inverter-based review process discussed above, the robust technical screening process is the ultimate arbiter of whether or not a system can receive Fast Track review. Thus, the rule of thumb in setting size limits should be to allow the largest sized project that could potentially pass the interconnection screens on the particular line size to use the Fast Track procedures. If the project is too large the screens will prevent the project from interconnecting without study. If the size limit is too low, projects could be forced into a multi-month, expensive study process unnecessarily.

- Section III.B.2.a of IREC's *Model Interconnection Procedures* incorporates a table-based approach to Level 2 eligibility.

Line Voltage	Level 2 (Fast Track) Eligibility	
	Regardless of Location	On > 600 amp line and < 2.5 miles from substation
< 4 kV	< 1 MW	< 2 MW
5 kV – 14 kV	< 2MW	< 3 MW
15 kV – 30 kV	< 3 MW	< 4 MW
31 kV – 60 kV	< 4 MW	< 5 MW

- NREL's *Updating Small Generator Interconnection Procedures for New Market Conditions* explains the Fast Track process and the rationale for adopting a table-based approach to eligibility (see pp. 19-21).
- Section 2.1 of the FERC SGIP also incorporates a Fast Track Eligibility table. Compared to the IREC and NREL tables, FERC relies on similar but slightly more conservative numbers that were negotiated during the tariff review process. The following states have also adopted a table based approach to Fast Track: Illinois, Iowa, Ohio, North Carolina, and South Carolina.
- For information on the amount of generation that can be potentially accommodated on different line voltages, see Tom Short, Electric Power Distribution Handbook, CRC Press, Section 1.3 (2004). A pdf version is available here.

E. Supplemental Review

If an interconnection applicant fails one or more of the Fast Track screens, many states' procedures allow it to undergo "supplemental review" or "additional review" to determine whether or not it could interconnect without full study. Until recently, however, this review was a "black box," providing no details on its scope, cost or process. In its most recent revision to SGIP, FERC integrated a more transparent supplemental review process that relies on three screens, including a penetration screen (Screen 1), set at 100 percent of minimum load. In most cases, if the proposed generation facility is below 100 percent of the minimum load measured at the time the generator will be online, then the risk of power backfeeding beyond the substation is minimal and thus there is a good possibility that power quality, voltage control and other safety and reliability concerns may be addressed without the need for a full study. The other two screens allow for utilities to evaluate any potential voltage and power quality (Screen 2) and/or safety and reliability impacts (Screen 3). Several states, including Ohio, Massachusetts, Illinois, Iowa and California, have adopted this transparent supplemental review process, and it is under consideration in others, including Maine and Minnesota.

In nascent solar markets, supplemental review may not seem immediately valuable, however as penetrations of solar increase, and more projects fail the Fast Track screens, particularly the 15 percent of peak load penetration screen, a transparent supplemental review process will become increasingly important. It provides additional time to resolve some of the safety and reliability concerns identified by the conservative initial review screens while still allowing for transparent, efficient and cost-effective interconnection of projects.

- Section 2.4 of the FERC SGIP describes its Supplemental Review process and the support for using a 100 percent of minimum load screen in it.
- IREC's *Model Interconnection Procedures* incorporate a nearly identical supplemental review process in Section III.D.
- NREL's *Updating Small Generator Interconnection Procedures for New Market Conditions* explains the rationale for a transparent supplemental review process and refers to California's process, which served as a model for the FERC SGIP (see pp. 30-31).
- This approach is currently used in California, Massachusetts, Hawaii, Illinois, Iowa, New York and Ohio.

II. Improving the Timeliness of the Interconnection Process

Below are some methods that could be considered to improve the timeliness of the interconnection process. In addition to these subsections, also note that a number of the other recommendations in this memorandum are likely to also assist with improving the timeliness of the interconnection process. In particular, the pre-application report can reduce the number of unrealistic project applications that have to be reviewed and also improve the quality of the application submittals, which speeds up the review process. The use of a robust Supplemental Review process can help move projects more efficiently through the process by requiring fewer projects to go to study and also giving developers information about their likely project costs earlier (this often means projects can make a decision whether to proceed in a more efficient manner). Finally, the section below on reporting requirements is likely to also have a significant impact on utility compliance with deadlines because they will be required to report delays to the Commission.

A. Electronic Application Submittal, Tracking and Signatures

One method for increasing the speed and efficiency of the interconnection process for both customers and utilities is to enable the use of technology to expedite the processing of applications. IREC's *Model Interconnection Procedures* include provisions that would allow for electronic submittal of applications and electronic signature of interconnection documents. In addition to being able to submit an application electronically, it is helpful to have an online interface wherein customers can track the progress of their application and be notified quickly of any deficiencies or delays. A number of utilities across the country utilize electronic submittal and processing techniques. Two California utilities have reported millions in dollars in annual savings through successful adoption of an electronic submittal and tracking process that has dramatically reduced processing times for NEM applications.[1]

"In addition to being able to submit an application electronically, it is helpful to have an online interface wherein customers can track the progress of their application and be notified quickly of any deficiencies or delays."

1. K. Ardani & R. Margolis, *Decreasing Soft Costs for Solar Photovoltaics by Improving the Interconnection Process: A Case Study of Pacific Gas and Electric*, at 7 (Sept. 2015), National Renewable Energy Laboratory, available at: www.nrel.gov/docs/fy15osti/65066.pdf; Electric Power Research Institute, PV Integration Case Study: SDG&E's Distributed Interconnection Information System (DIIS), *Solar PV Market Update, Volume 10: Q2 2014,* at 4 (June 2014), available at: https://www.sdge.com/sites/default/files/documents/1508554296/EPRI%20DIIS%20Case%20Study.pdf

B. Ensure That Projects are Cleared from the Queue If They Do Not Progress

One way to better enable utilities to keep up with the timelines set forth in the procedures is to make sure they are focusing their efforts on projects that are ready to move forward. It is often true that interconnection backlogs can be due to delays on the customer's end and not just by the utility. Particularly for projects in the study process, it is important that they keep up with their responsibilities in the tariff or that they withdraw. Failure to do so results in delays for all projects that are later in the queue. Since projects are studied "serially" in most cases, projects stalled in the queue effectively reserve capacity that should be made available to later queued projects at some point. Massachusetts, California, North Carolina and New York have all recently adopted processes that allow projects to be removed from the queue if they fail to move forward in an efficient manner.

C. Include Timelines for Construction of Upgrades and Meter Installs

It is often the case that interconnection procedures contain detailed timelines for the interconnection application review process, but little if any detail regarding the timeliness of the steps that have to be taken after an interconnection agreement is signed. Procedures should include specific and enforceable timelines for construction upgrades and meter installs to avoid unnecessary delays once interconnections are approved.

D. Implement a More Efficient Dispute Resolution Process

When delays do arise due to disagreements about the rules, technical requirements or costs, developers often do not seek to resolve them through existing dispute resolution procedures because those processes can often drag out longer than the delay. In addition, developers are often hesitant to use those procedures for fear that it will damage their working relationship with the utility going forward. One strategy for states to consider is to appoint an ombudsman within the Commission, or at the utility, to who could help facilitate resolution of minor complaints in a timely manner. New York and Massachusetts use ombudspersons within the Commission to help resolve disputes, and Minnesota used an ad hoc process involving outside engineers to help mediate interconnection disputes. Another option would be to appoint a technical master to help facilitate resolution of disputes regarding technical requirements.

E. Implement Enforcement Measures for Utility Compliance

Interconnection standards should contain clear requirements for when utilities and customers must complete each step of the interconnection process. In addition, there should be a meaningful mechanism to enforce compliance with the timelines. This has been a challenging issue across the United States with very few state policies that provide for meaningful enforcement. The only significant example comes from Massachusetts, which recently approved a "timeline enforcement mechanism," which would impose monetary penalties on the utilities if they fail to meet timelines specified within the interconnection procedures.[2] The proposed mechanism was developed collaboratively and submitted jointly by utilities, developers, and the Massachusetts Department of Energy Resources. New York has adopted an "earnings adjustment mechanism" that connects utilities' performance incentives (and/or penalties) on interconnection timelines and customer satisfaction with the process.

> "Publication of an interconnection queue, along with regular reporting can allow applicants to see how many projects require utility review before them and the status of their review, thereby giving them a more realistic sense of timing."

III. Improving Grid Transparency and Access to Information

A. Transparency and Reporting Requirements

Transparency and reporting regarding the interconnection process, and specifically the interconnection queue—that is, the order projects proceed through the process and their status—can be beneficial for interconnection applicants as well as utility regulators and others interested in understanding the process. Publication of an interconnection queue, along with regular reporting can allow applicants to see how many projects require utility review before them and the status of their review, thereby giving them a more realistic sense of timing. In addition, similar to the pre-application report and distribution system mapping discussed below, a public interconnection queue can show where applicants earlier in the queue are located, and therefore help later applicants determine which locations may have limited capacity and thus would be more likely to require costly interconnection review. A public interconnection queue and regular reporting can also help to identify bottlenecks or other problems for utilities and regulators to address.

- The Massachusetts Department of Energy Resources (DOER) collects monthly data from the utilities, which it provides on a publicly accessible website (click on "Interconnection activity").
- In California, each utility has a detailed interconnection queue:
  - Pacific Gas and Electric Company (PG&E) (see "What's New: Public Queue").
  - San Diego Gas & Electric Company (SDG&E) (see "SDG&E Generation Interconnection Request Queue (WDAT & Rule 21)").
  - Southern California Edison Company (SCE) (see "Public WDAT-Rule 21 Queue").
- The Hawaiian Electric Company (HECO) provides an Integrated Interconnection Queue for interconnections on Hawaii and Maui.

B. Utility Distribution System Maps

Similar to the pre-application reports, discussed below, utility maps can help potential interconnection applicants to evaluate siting options for their projects and avoid wasted resources spent on evaluating interconnection applications for projects located at poor grid locations that will never be built. In

2. Mass. Dept. of Pub. Utils., DPU 11-75-F, Order on a Timeline Enforcement Mechanism (July 31, 2014) (Appendix B to the order contains a clean version of the mechanism) and DPU 11-75-G, Order on the Model Interconnection Tariff (May 4, 2015).

particular, maps can identify grid characteristics (e.g., substation or line capacity, existing generation capacity on a line, available capacity for new generation, etc.) and areas of the grid that can accommodate new generation as well as areas that cannot accommodate new generation without significant upgrades (i.e., at a significant cost). Maps can also identify areas where projects might provide system benefits. When this kind of information is provided in advance in a publicly accessible way, potential applicants can use it to narrow down locations for their projects and submit fewer dead-end applications. Although maps can take some resources upfront to develop, they can save utilities time and money in the long run because they do not have to respond to individual information requests or evaluate applications submitted only to get the locational information that will instead be provided via the maps.

- The New York utilities have all recently launched maps that provide information on good potential points of interconnection.
- ComEd has more basic maps for its service territory in Illinois.
- The Hawaiian Electric Company (HECO) provides "Locational Value Maps" that provide an indication of the percentage of DG on the utilities' distribution circuits.
- Delmarva Power provides a map of "restricted circuits" in their territory in Delaware.
- The California utilities have some of the most robust maps available today. Originally called "preferred location" maps, they are now evolving to include full hosting capacity information.
    - Southern California Edison (SCE) (click "Content" on left side of page and zoom in on map to see detail)
    - Pacific Gas & Electric (PG&E) (registration required)
    - San Diego Gas & Electric (SDG&E) (registration required)
- Minnesota and Maryland are undertaking similar processes as part of their grid modernization proceedings.
    - Pepco, a regulated electric utility serving customers in Maryland and the District of Columbia, has developed a detailed hosting capacity map that provides available capacity at the distribution feeder level.

C. Pre-application Reports

While maps can provide a helpful, high-level picture of optimal and non-optimal grid locations, pre-application reports can allow potential applicants to obtain more granular information about potential project locations. The pre-application report is intended to require limited effort from the utility and, in most cases, relies entirely on pre-existing data. Pre-application reports can be optional or mandatory for all or some subset of projects, such as larger projects expected to have greater system impacts. Most pre-application reports require a relatively minimal fee (e.g., $300).

Since first introduced in California, pre-application reports have been widely accepted as a useful tool by both developers and utilities in all states IREC has appeared in recently. Indeed, California recently expanded their pre-application process to include an "enhanced" report that allows potential applicants to obtain more site-specific information that can sometimes require a utility truck-roll in exchange for an additional fee.

- The Federal Energy Regulatory Commission (FERC) has incorporated a pre-application report requirement into Section 1.2 of its Small Generator Interconnection Procedures (SGIP), which were revised in 2013.
- IREC's *Model Interconnection Procedures* (2013) include a pre-application report in Section II. In addition, IREC has developed a model pre-application request form for use in North Carolina and Illinois that could be easily modified for South Carolina.
- Finally, a paper published by the National Renewable Energy Laboratory, *Updating Small Generator Interconnection Procedures for New Market Conditions* (2012) , pp. 12-15, provides an explanation of why pre-application information is so valuable.

Other states that have adopted a pre-application report include Massachusetts, Iowa, Illinois, Ohio, North Carolina, South Carolina, and New York.

Taking the mapping and pre-application reporting components one step further, some states and utilities have begun to conduct hosting capacity analyses that allow potential interconnection applicants to access significantly more detailed and accurate information about the state of the grid at the proposed point of interconnection. A hosting capacity analysis determines how much capacity there is for additional distributed energy resources (load or generation) at precise points on the grid without the need for traditional upgrades to the system. In addition to the map interface, a hosting capacity analysis will also include downloadable data that will provide applicants with the detailed load curves for particular sites that can significantly assist with "right-sizing" of projects for each location.

IV. Allowing Construction for Level 1 & 2 Projects

Many state procedures and the FERC SGIP force a project to fail a Level 1 or 2 screen if the project would require any construction to be interconnected. Some states allow construction through the supplemental review process, but often this process is not well used. The effect of this screen is that a project may have been determined to not pose any system impacts (which is what the other technical screens evaluate), but still have to go through the full study process simply to determine the costs of any upgrades. In some cases, utilities do not adhere strictly to this rule and allow some construction. As utilities have gained more experience with the interconnection of distributed generation facilities it has become apparent that it is not necessary to send a project to the full study process just because some construction is required. If a project triggers construction after having passed the other Level 1 or 2 screens it means that the required construction does not require a system impacts study, and it is likely the construction is minor enough that a full facilities study is not warranted either. For example, it is common for a project to need to have interconnection facilities constructed. Interconnection facilities do not have upstream impacts and thus there is not a need to conduct a full system impacts study in order to move ahead with approving the project. In addition,

"... some states and utilities have begun to conduct hosting capacity analyses that allow potential interconnection applicants to access significantly more detailed and accurate information about the state of the grid at the proposed point of interconnection."

"Many utilities and interconnection applicants are discovering, however, that the feasibility study is not necessary or valuable in all cases and can be eliminated in the interest of time and cost efficiency."

some utilities have recognized that it is more efficient for them to allow the upgrading of line transformers and certain other equipment at this stage. Thus, a process has been developed to allow Level 1 & 2 projects to still proceed even if they require construction. For minor construction, a cost estimate is provided, and for more significant upgrades, a utility may opt to prepare a Facilities Study.

- FERC approved modifications to the wholesale tariffs of SCE and PG&E to allow for certain construction in 2011. It also included a process to allow projects in the supplemental review process to proceed even if some construction is required.
- Numerous states have moved away from using a no construction screen, including North Carolina, Illinois, South Carolina, California and Massachusetts.

V. Consolidating the Study Process

When projects are either ineligible for or fail to pass through expedited review they must undergo a more thorough study process in order for the utility to be able to determine what system impacts the project may pose, to design solutions to mitigate for any impacts, and to identify and allocate the costs for these solutions. Following the lead of the FERC LGIP and SGIP, many state procedures contain a three-tier study process, which includes a feasibility study, a system impacts study, and a facilities study. Altogether the processing of three layers of study can take many months. Many utilities and interconnection applicants are discovering, however, that the feasibility study is not necessary or valuable in all cases and can be eliminated in the interest of time and cost efficiency.

- Some states such as Minnesota, New York, and Nevada have a single study that combines the assessment of system impacts with the determination of the upgrade costs. This can result in a more efficient review process, but it also means that an applicant may end up paying for the development of a cost estimate even if they would be unlikely to proceed after learning of the system impact results.
- Other states have started to just eliminate the feasibility study in favor of a two-tier study process, including North and South Carolina.
- A paper published by NREL, *Updating Small Generator Interconnection Procedures for New Market Conditions* (2012) , pp. 31-36, provides a discussion of possible methods to improve the efficiency of the study process itself.

VI. Determination of Upgrade Costs

Once a utility has examined the potential impact a project may have on the system they may identify upgrades that need to be completed to allow the project to go forward. The process for determining upgrade costs, providing estimates, and ensuring those estimates are meaningful has been a source of considerable discussion in many high penetration states lately. There are three central concepts: cost predictability, cost certainty, and cost allocation. There are not yet clearly established best practices in these areas, but there are a few key practices that are beginning to take hold and warrant consideration.

- **Cost Tables:** At the transmission level it is common for Independent System Operators (ISOs) and Regional Transmission Organization (RTOs) to publish cost tables that show the prices of typical equipment to enable customers to have a better sense of the expected cost of undertaking specific upgrades. The California utilities agreed to publish a cost table for distribution level interconnections as well. In addition to helping provide more transparency and predictability into the interconnection costs, this process also can reduce concerns about utility manipulation of cost estimates.
- **Cost Envelopes:** Massachusetts was the first state to implement a process that requires the utilities to provide a binding cost estimate to interconnection applicants. Depending upon what stage the customer requests the estimate, it cannot exceed the estimated amount by either 25% (if sought earlier in the process) or 10% (if obtained at the end of the review process). This cost envelope approach means that the utility is responsible for any costs that exceed those inflation amounts. California recently implemented a similar cost envelope process, using a 25% threshold, and allowing utilities to seek rate recovery for overages if they can show their failure to accurately estimate the costs was reasonable. New York's new rules contain softer language that could impose a greater burden on utilities to provide accurate estimates.
- **Detailed Cost Estimates:** Another way to improve the transparency of the interconnection upgrade cost process is to require that utilities provide more detail in their interconnection cost estimates. Though it varies by utility, often cost estimates contain no more than one bulk figure with no further information on the cost of the components and labor that make up that cost. Instead, the estimate given could provide a list of the major equipment required and particular prices along with a breakdown of the utility time that will be spent reviewing and constructing the upgrades. Providing detailed estimates should improve the accuracy of the estimates and also the confidence the applicant has that the costs assessed are being charged at reasonable rates.
- **Cost Allocation:** How interconnection costs are divided between different interconnection customers is a topic that has been raised in various states in recent years, but there has not yet been considerable progress in developing functional mechanisms that improve the allocation of costs across responsible customers. The distribution level interconnection process typically operates on a cost causation principle that assigns the full cost of system upgrades to the first project that triggers the need for them. This applicant will bear the full cost of the upgrade, although projects before them may have contributed to the need for the upgrade, and later queued projects may also take advantage of the increased capacity

created by the upgrade. This process creates perverse incentives and behavior in many cases, can be a central cause of queue backlogs, and prevent upgrades from occurring that might be economically efficient if spread across all potential beneficiaries. On the transmission system costs are usually paid back over a period of years since the system is networked and the idea is that all projects ultimately benefit the system. However, more limited examples of cost sharing exist on the distribution system.

- Some states such as California and Massachusetts have experimented with “group studies” on the distribution system, and Massachusetts’ standards contain a rule that requires allocation of costs across customers, but it is not clear how often this rule is actually applied.[3]
- New York just launched one of the first examples of a formal cost sharing mechanism for projects that are not being studied concurrently. For upgrades of a certain type and cost, the generator that first triggers the need for the project will cover all the costs upfront, but a mechanism has been put in place to require later projects to reimburse the first project if they connect within a defined period of time.

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3. MA DPU 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.”).

Additional Resources

- Interstate Renewable Energy Council, Model Interconnection Procedures, (April 2013), available at: http://www.irecusa.org/publications/model-interconnection-procedures/ (last accessed June 5, 2017).

- Sky Stanfield et al., *Charging Ahead: An Energy Storage Guide for State Policymakers*, Interstate Renewable Energy Council, (April 2017), available at: http://www.irecusa.org/publications/charging-ahead-an-energy-storage-guide-for-policymakers/ (last accessed June 5, 2017).

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- Kristen Ardani et al., *State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States*, National Renewable Energy Laboratory, (January 2015), available at: http://www.nrel.gov/docs/fy15osti/63556.pdf (last accessed June 5, 2017).

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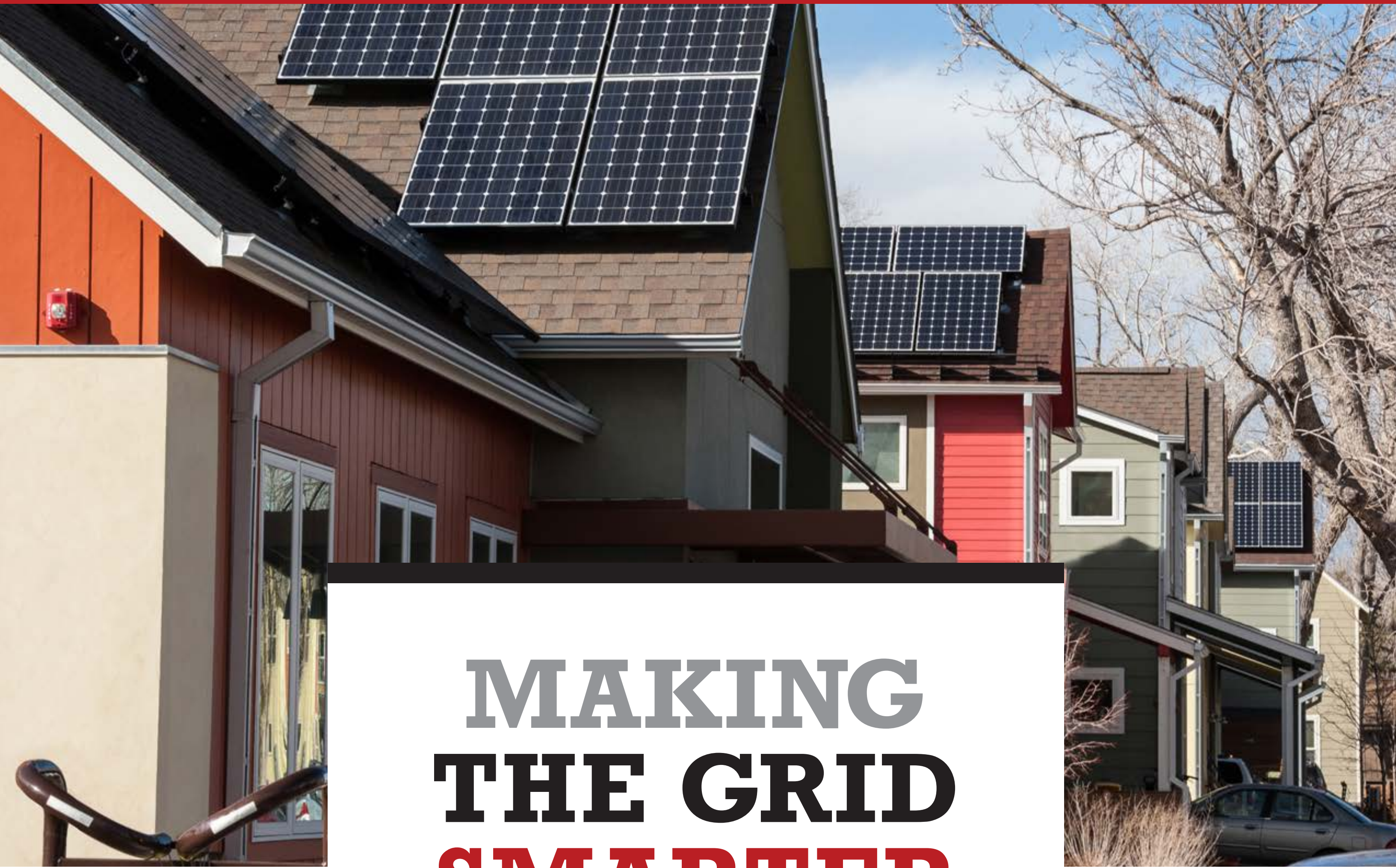
EXHIBIT 3



MAKING THE GRID SMARTER

Primer on Adopting the New IEEE 1547™-2018 Standard for Distributed Energy Resources

JANUARY 2019

IREC
Interstate Renewable Energy Council

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Interstate Renewable Energy Council

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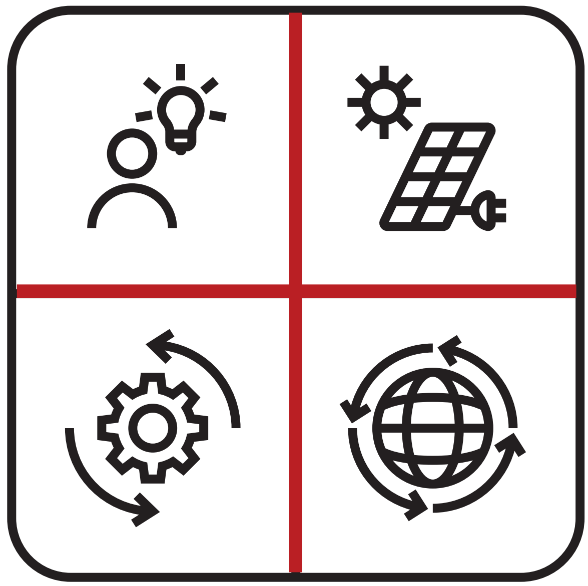
Executive Summary

In April 2018, the Institute of Electrical and Electronics Engineers (IEEE) published the *IEEE Standard 1547™-2018 for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547™-2018 or the Standard)*, which is a voluntary, nationally-applicable Standard that will transform how distributed energy resources (DERs) interact with and function on the electric distribution system. It is the long-awaited update to *IEEE Standard 1547™-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE Std 1547™-2003)*.



The Standard requires DERs to be capable of providing specific grid supportive functionalities relating to voltage, frequency, communications and controls. Once widely utilized, these functionalities will likely enable higher penetration of DERs on the grid, while maintaining grid safety and reliability and providing new grid and consumer benefits. Even in states where DER penetration remains low today, implementing IEEE Std 1547™-2018 sooner rather than later will help ensure new DERs meet the most updated performance standards, provide enhanced grid functionality, and avoid high volumes of legacy systems that do not provide such capabilities.

State adoption and implementation of this Standard will require the attention of state regulators – who will be tasked with formally adopting the new Standard at the state level – as well as utilities who will integrate them into internal interconnection protocols. In addition, DER industry representatives, technology manufacturers, state and federal agencies, national laboratories and advocates will play key roles in the consideration and adoption of the new Standard. In contrast with the 2003 Standard, which provided one set of requirements for all DERs, IEEE Std 1547™-2018 features a menu of options that need to be considered and selected.

State implementation of IEEE Std 1547™-2018 will benefit from fair, balanced and transparent stakeholder processes to ensure that the perspectives of all impacted stakeholders, including consumers adopting DERs, are accounted for and reflected.

This primer provides an overview and explanation of the major revisions in IEEE Std 1547™-2018 and the issues that regulators, utilities and other stakeholders will need to consider as they work

With this reference guide in hand, those working to address and integrate the updated standards will be better equipped to streamline the implementation process and optimize the rules governing the grid.

through adopting and implementing the Standard. While not attempting to provide in-depth details of the entire Standard, this document provides an accessible overview and insights on the following topics:

- The key requirements and implications of IEEE Std 1547™-2018 and impacts on its adoption and implementation for regulators, utilities, DER developers, customers and the grid;
- The anticipated timeline for the full rollout of IEEE Std 1547™-2018, including the development of applicable test procedures and equipment certification standards;
- DER performance categories for reactive power, and performance during abnormal voltage and frequency conditions, and key issues for consideration;
- Voltage regulation functions and corresponding implications of these functions on the grid and DER developers;
- IEEE Std 1547™-2018 compliant communications protocols, controls and functional settings for DERs and issues surrounding their integration and harmonization across different networks and between technologies;
- Updates to power quality requirements, including new limits for rapid voltage changes, flicker and overvoltage;
- Issues surrounding grounding practices, islanding, secondary networks, fault current, and power limitations at the point of common coupling (all of which will likely impact state interconnection procedures and protocols);
- DER testing and verification, including DER design and as-built evaluations, as well as commissioning and periodic tests and DER settings verifications; and
- Key takeaways and overarching policy issues states and regulators should consider as they work to adopt and implement IEEE Std 1547™-2018.

With IEEE Std 1547™-2018 published and a few remaining years before full rollout (2022), now is the time for states and regulators to begin to implement the updated Standard. Early consideration and integration of IEEE Std 1547™-2018 and related standards will ensure states have ample time to navigate the complex issues that involve stakeholder coordination and pave a smooth path for widespread deployment of smarter DER technologies. With this reference guide in hand, those working to address and integrate the updated standards will be better equipped to streamline the implementation process and optimize the rules governing the grid.

I. Introduction to the IEEE 1547™-2018 Standard

In April of 2018, the Institute of Electrical and Electronics Engineers (IEEE) published a major revision of the national Standard for interconnection of DERs known as the *IEEE Standard 1547™-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547™-2018 or the Standard).*[1] The Standard requires DERs to provide capabilities for specific grid supportive functionalities, including voltage and frequency ride-through, voltage and frequency regulation, as well as communications and control functionality. In addition, they may provide enhanced functions, such as ancillary services. When utilized, these capabilities can help increase the amount of DERs that can be accommodated on the grid, improve power quality for all customers, and ensure that DERs can continue to be a reliable and optimized grid resource as penetration increases.

These new requirements will enable DERs to communicate with and receive signals from the grid operator or a third party (aggregator). Although applicable for any type of DER, the majority of new DERs interconnecting to the gird in the coming years are expected to be inverter-based DERs with so-called "smart inverters" or "advanced inverters" that can comply with the new Standard. Using more sophisticated communication infrastructure, these smart inverters can be controlled and monitored remotely. Among other advantages, these communications and controls will enable DERs to convey performance data with the utility (or an aggregator) to increase situational awareness and more quickly diagnose and address any operational or maintenance issues.

IEEE Std 1547™-2018 represents a considerable shift from the 15-year old IEEE Standard 1547™-2003, *IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems* (IEEE Std 1547™-2003) in that the 2018 version has no single default set of DER capabilities and settings.

1 In June of 2018, IEEE published errata that corrected an erroneous sign in the frequency-droop formula of Table 23 of Clause 6.5.2.7.

The Standard requires DERs to provide capabilities for specific grid supportive functionalities, including voltage and frequency ride-through, voltage and frequency regulation, as well as communications and control functionality.

The updated Standard is a menu with options that need to be selected dependent on technology, location or other factors. Although each entity will be responding and adapting to the new Standard in different ways, IEEE Std 1547™-2018 will have an impact on DER developers, installers, manufacturers, customers and utilities. As they work to adopt and implement the new Standard, state utility regulators will play an important role in ensuring that all stakeholders' interests are balanced, with the overall goal of increasing the safety, security, resilience and reliability of the grid.

Once widely implemented, IEEE Std 1547™-2018 will result in the following primary changes:

- **The interconnection process used for DERs connecting to the grid will change.**
- **The large number of optional functions and settings will require development of a process to verify the DER settings in the commissioning process.**
- **DERs will have the ability to automatically respond to certain grid conditions, which will help avoid potential negative impacts and optimize their grid benefits.**
- **More DERs will be capable of connecting to the grid under higher penetration scenarios, assuming their control functions are set up adequately to accommodate the grid conditions.**
- **Standardized communication protocol capabilities could allow for wider control of DERs through integration with Supervisory Control and Data Acquisition (SCADA) systems or Distributed Energy Resource Management Systems (DERMS).**
- **Customers installing DERs may see shifts in their distributed generation output under certain scenarios, which might require the adoption of new consumer protection measures.**

The optionality inherent to IEEE Std 1547™-2018 may be more challenging to apply uniformly, with potential for different implications for certain functions based on DER system size, technology or local grid conditions. This document provides an overview and explanation of the major revisions in IEEE Std 1547™-2018 and a synopsis of some of the issues that states will need to consider as they work through adopting the updated Standard.

II. Anticipated Timeline for Full Rollout

With IEEE Std 1547™-2018 now formally published, work to publish revisions to the accompanying IEEE Standard 1547.1™, *IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems* (IEEE Std 1547.1™), is underway. IEEE Std 1547.1™ will guide manufacturers as they test and certify their products to the IEEE Std 1547™-2018 Standard. IEEE Std 1547.1™ is expected to be published in 2019-2020. Underwriters Laboratories (UL) will then update its product certification standard, *Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources* (UL 1741), to which all equipment must be tested and certified. UL is coordinating closely with IEEE and has stated the revision to UL 1741 will likely be available within a few weeks following publication of the revised IEEE Std 1547.1™. From that point, it is anticipated that it will then take up to 18 months for all DER products to comply with the updated requirements and be made commercially available (see Figure 1).

Figure 1: Anticipated Timeline for the Rollout of IEEE Std 1547™-2018

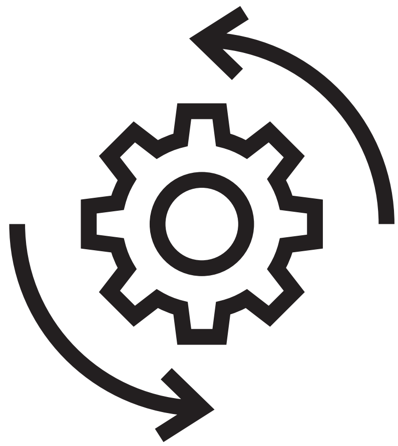
In addition to considering the above timeline, local, state or regional DER market conditions may inform whether a more expedited process to adopt the new Standard (or parts thereof) is warranted in advance of the development of IEEE Std 1547.1™ and UL 1741 updates. For example, California and Hawaii expended significant effort to initiate smart inverter implementation efforts in advance of the adoption of IEEE Std 1547™-2018 due to the prevalence of DERs on their respective utilities' grids. Implementation efforts in both states are still underway, and harmonization with IEEE Std 1547™-2018 will be required.[2]

For most states, given the increased menu of options within the updated Standard, it will likely be a worthwhile exercise to begin a stakeholder process or formal proceeding in the near-term in order to ready the state and utilities for the full rollout of IEEE Std 1547™-2018. Namely, to ensure the streamlined integration of DERs with enhanced capabilities and functions envisioned by IEEE Std 1547™-2018, it will be important to ensure that rules are in place by the time certified DER devices are available on the market. As part of its order adopting updated interconnection standards for its regulated utilities, the Minnesota Public Service Commission has already convened a workgroup to evaluate the integration of the IEEE Std 1547™-2018 as part of the state's development of the Minnesota Distributed Energy Resources Technical Interconnection and Interoperability Requirements.[3]

2 Currently, the requirements are state-specific and are predicated on the smart inverter test protocols of UL 1741 Supplement SA instead of IEEE Std 1547.1™.

3 Minnesota Public Service Commission, Docket Nos. E-999/CI-01-1023 and E-999/CI-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement (August 13, 2018).

III. Integration of IEEE Std 1547™-2018 into Interconnection Rules



The use of DERs is expanding quickly as more people are seeking to adopt distributed grid-integrated technologies in their homes, businesses, communities and public institutions. IEEE Std 1547™-2018 is a core standard that will maintain or increase the stability, reliability and intelligence of the distribution grid over time, as DER levels increase. The new Standard also addresses increasing aggregate DER impacts on the bulk power system. Even in states where DER penetration is low today, implementing the new Standard will help ensure new DERs meet the most updated performance standards, while giving latitude to utilize the enhanced grid functionality as the volume of DERs increases on the grid (avoiding the preponderance of legacy DERs).

Any current state rules and utility interconnection procedures that are based on IEEE Std 1547™-2003 will need to be updated to reflect these recent revisions. Clearly defining DER settings in statewide interconnection rules[4] will help increase efficiency, minimize confusion, and reduce costs. States or utilities that have not yet adopted interconnection rules could begin the process today with IEEE Std 1547™-2018 in mind, rather than retroactively adopting it (which could be inefficient and resource intensive for all involved stakeholders).

Rather than a single package of default settings that work in all instances and for all technologies, IEEE Std 1547™-2018 adds new features and requirements and includes more flexibility and options. Utilities and state regulatory commissions will need to evaluate, select and assign different "performance categories" for different DERs. In addition, as applicable, states and utilities will need to consult and coordinate with the Regional Reliability Coordinator and Regional Transmission Organization (RTO), Independent System Operator (ISO), or other transmission operator on certain issues within IEEE Std 1547™-2018 relating to reliability and performance. Starting now to adopt IEEE Std 1547™-2018 will give state regulators, utilities, DER developers and customers the time necessary to navigate some of the more complex issues to integrate and enhance the adoption of smarter grid technologies.

To make the most of the standard and prepare for higher DER penetration in the future, regulators and utilities should consider the opportunity to utilize certain functions before achieving higher penetration of DERs, so as to optimize future DER growth and avoid negative impacts as

4 As applicable to those utilities regulated by state public service commissions. Other utilities not regulated by a state regulatory commission could integrate IEEE Std 1547™-2018 into their applicable interconnection rules and tariffs (voluntarily or as directed by state statute).

Any current state rules and utility interconnection procedures that are based on IEEE Std 1547™-2003 will need to be updated to reflect these recent revisions. Clearly defining DER settings in statewide interconnection rules will help increase efficiency, minimize confusion, and reduce costs.

penetration increases. For example, as discussed below in Section V.B, high penetration of DERs on certain circuits can potentially affect the voltage of the grid, which could negatively impact power quality if not managed. IEEE Std 1547™-2018 requires DERs to be capable of participating in voltage regulation, through a number of functions that may be activated. Voltage regulation can help mitigate any negative grid impacts while also allowing DERs to connect to locations on the grid where once they might not have been able to do so. States and utilities will need to determine if and when voltage regulation functions should be turned on (since voltage regulation is disabled by default in the new Standard), which function should be utilized, which settings should be used, and how enabling these functions will interact with interconnection rules. The implementation of voltage regulation functions will also warrant consideration of the impacts on and protections for individual DER customers. The voltage regulation example is just one of many that states will be tasked with evaluating as part of their adoption of IEEE Std 1547™-2018.

Even though the full implementation of the updated Standard will take a few more years, it is not too soon for states, utility regulators, utilities and stakeholders to begin the process to adopt and integrate it into interconnection rules.

Alongside existing interconnection best practices, IEEE Std 1547™-2018 can support the optimized integration of new technologies, while maintaining grid safety and reliability. Even states and utilities with low levels of DER deployment could adopt IEEE Std 1547™-2018 in order to build up the functional capabilities, while still specifying settings close or equal to those from IEEE Std 1547™-2003. For states with multiple regulated utilities, statewide adoption of IEEE Std 1547™-2018 will provide greater consistency across utilities and enable a more streamlined rollout of the Standard, which will benefit consumers, utilities and DER developers alike.

IV. Reference Point of Applicability and Evaluation, Commissioning and Verification of DERs

In adopting the IEEE Std 1547™-2018, it is important to clarify the physical point on the electric grid where compliance with the Standard's requirements will be assessed. This point is known as the *reference point of applicability*[5] and it determines which method is used to evaluate compliance with the Standard. For most large DER systems, this will be the Point of Common Coupling (PCC), which is the point of connection between the DER customer and the utility.[6] However, for some systems, especially smaller DER projects[7], the reference point of applicability for the IEEE Std 1547™-2018 requirements may be the Point of DER Connection (PoC), which is the point where a DER is electrically connected on a customer's site and meets the requirements of IEEE Std 1547™-2018, exclusive of any load present in the respective portion of the customer's site.

IEEE Std 1547™-2018 details specific DER evaluation[8] and commissioning testing requirements, and the tables therein indicate which evaluations or commissioning tests should be performed based on the reference point of applicability (and whether or not fully tested, fully compliant DER units are utilized). Further details on the extent of those evaluations and commissioning tests will be given in the next version of IEEE Std 1547.1™. Generally speaking, the DER project size, configuration and equipment determine the reference point of applicability and corresponding compliance methods. For example:

- **For DER projects that regularly export more than 500 kVA[9] (i.e., larger systems or dedicated generating facilities), the requirements of IEEE Std 1547™-2018 must be met at the PCC. In addition to evaluation by the utility to verify compliance, additional equipment commissioning testing may be required.**
- **For smaller DERs, using the PoC as the reference point of applicability allows the DER equipment type testing certification to be utilized as the main method by which compliance with the Standard is verified. The PoC might be the terminals of an inverter, for example, and utilizing a UL 1741 certified and listed inverter would be sufficient to demonstrate Standard compliance.[10]**

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5 See IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, IEEE Std 1547™-2018, subclause 4.2.

6 Typically, at the utility revenue meter.

7 Either a) DER nameplate rating ≤ 500 kVA, or b) average load demand greater than 10% of DER nameplate and where it does not export more than 500 kVA for longer than 30 seconds, as with an "inadvertent export" system.

8 Evaluation is the review of the design of the DER system and/or a review of the "as-built" DER system, typically performed by a utility engineer.

9 See "Power limitation at the PCC" section for discussion on how export may be limited to 500 kVA or less.

10 If "zero-sequence continuity" is not maintained between PCC and PoC, then sensing for faults, open-phase and voltage must be accomplished at another appropriate location.

- A DER system comprised of a DER unit or DER units (e.g., individual inverters) that is type tested for full compliance with the Standard can be considered in compliance at the PCC as long as the interconnection system (between the PoC and PCC) does not interfere with proper operation of the required DER functionality.[11]
- A DER unit that is not fully compliant with IEEE Std 1547™-2018 could be utilized along with supplementary devices (e.g., additional equipment to provide reactive power capability) such that the system as a whole meets the requirements of the Standard, whether at the PCC or PoC. Given the increased challenge of verifying compliance where multiple pieces of equipment are utilized to meet the requirements, more detailed evaluation and commissioning testing may be required.[12] Given that this is an evolving field and verification practices may differ substantially among utilities, IEEE Std 1547™-2018 only gives some guidance and does not specify mandatory requirements.

Interconnection rules should allow for the appropriate level of evaluation and commissioning testing to be performed as part of the interconnection review process, dependent on the variables described in IEEE Std 1547™-2018. Any projects that go through fast track or supplemental review[13] should also align with the relevant evaluation and commissioning protocols, to maintain an expedited and streamlined process for systems eligible within this level of review.

Verification[14] of functional settings (e.g., trip and voltage regulation settings) is an important aspect of commissioning that becomes more complicated by the additional functions and variety of settings that IEEE Std 1547™-2018 allows. Many inverters include settings profiles (a.k.a., manufacturer-automated profiles) that allow all relevant operational parameters to be automatically loaded by selecting one of a few default options. Adopting IEEE Std 1547™-2018 default values for functional settings will help simplify the DER project verification process, since smart inverters will automatically be equipped with these default setting profiles. However, to the extent states and utilities across the country adopt different trip and functional settings, new processes and/or verification measures may need to be developed to ensure that the DERs are commissioned appropriately.

At this juncture, efforts continue to simplify the process of quickly conveying settings from a utility (a.k.a. utility-required profile) to the DER (a.k.a. manufacturer-automated profile) in a standardized format (e.g., using digital means). Stakeholders should remain aware of those evolving discussions and adjust processes as necessary over time.

11 Lack of "interference" is defined in IEEE Std 1547™-2018 as having an impedance less than 0.5% between PoC and PCC.

12 The evaluation and commissioning tests can be simplified if the DER unit is certified in combination with the supplemental equipment.

13 Interstate Renewable Energy Council, *Priority Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators*, p. 6, August 2017, available at: ***https://irecusa.org/priority-considerations-for-interconnection-standards***. "The Fast Track process consists of several technical screens intended to easily identify proposed interconnections that will not threaten the safety and reliability of the electric system, and allow these systems to proceed through an expedited review process. Although the technical screens decide whether a project will be able to interconnect without a full study, an overall size limit for Fast Track eligibility offers applicants a useful indicator as to whether or not their system is at all likely to pass those screens and serves an administrative function for utilities to help sort projects into the proper study track. In the former iteration of the FERC SGIP and in many states' procedures, Fast Track review is limited to systems up to 2 MW. More recently, FERC and several states have moved away from a broadly applicable cap to a more nuanced, table-based approach, which accounts for location-related factors that affect the likelihood of the generator to have adverse impacts on the electric system. Specifically, the table-based approach allows the size limit to increase as the voltage of the line increases and if a generator is closer to the substation." And "If an interconnection applicant fails one or more of the Fast Track screens, many states' procedures allow it to undergo 'supplemental review' or 'additional review' to determine whether or not it could interconnect without full study. . . In its most recent revision to SGIP, FERC integrated a more transparent supplemental review process that relies on three screens, including a penetration screen (Screen 1), set at 100 percent of minimum load. In most cases, if the proposed generation facility is below 100 percent of the minimum load measured at the time the generator will be online, then the risk of power back-feeding beyond the substation is minimal and thus there is a good possibility that power quality, voltage control and other safety and reliability concerns may be addressed without the need for a full study. The other two screens allow for utilities to evaluate any potential voltage and power quality (Screen 2) and/or safety and reliability impacts (Screen 3)."

14 See IEEE Std 1547™-2018, clause 11.

V. IEEE Std 1547™- 2018 Categories, Functions and Issues for Consideration

A. Category Explanation and Assignment

IEEE Std 1547™-2018 identifies two performance categories[15] relevant to DER grid functionality: the Normal Operating Performance Category and the Abnormal Operating Performance Category. The Normal Operating Performance Category specifies how the DER should perform with regards to voltage control during normal grid operations. The Abnormal Operating Performance Category specifies DER performance during a grid disturbance such as a transmission fault or loss of a generator. Within each, there are options to further clarify the performance and functional capability levels. The assignment of these categories will determine the interconnected DERs' capability to respond to changing grid conditions and support and maintain electric grid power quality and stability.

Certain DER technologies are capable of different levels of performance. As one example, inverters used with solar photovoltaic (PV) and energy storage systems are capable of the highest level of grid performance for both normal and abnormal conditions. Other technologies may not be able to accommodate the highest level of performance. As such, the category assignment and level of performance may need to be determined on a technology-specific or use case-specific basis. Annex B of IEEE Std 1547™-2018 contains further discussion of how categories might be selected. The two categories and the primary issues within each are as follows:

- **The Normal Operating Performance Category (normal category) determines the level of *reactive power*[16] support a DER system must be capable of providing, and there are two options to determine the amount of reactive power support available: *Category A* and *Category B*. Category B provides the most reactive power support. IEEE Std 1547™-2018 requires all DERs to be capable of providing reactive power in order to regulate and maintain voltage within the American National Standards Institute (ANSI) C84.1 range A, which is considered the normal range for the U.S. electric grid (hereinafter normal range). The normal category mostly determines how well the DER can support local voltage to stay within the normal range.**

15 See IEEE Std 1547™-2018, clauses 5 and 6.

16 Reactive power, measured in *vars*, is power that does not do work, but is stored or returned to the circuit every half cycle. Reactive power results whenever the voltage and current waveforms are shifted in time relative to one another (known as a phase shift or "out of phase"), rather than being aligned (crossing zero at the same time or "in phase").

- The **Abnormal Operating Performance Category** (abnormal category) determines the level of voltage and frequency *ride-through capability*, and within this are three options of performance: *Category I*, *Category II* and *Category III*. The assignment of the abnormal category will determine the aggregate DER impact on the bulk power system (i.e., the transmission system and wholesale electric grid). To a large extent, the voltage and frequency ride-through capabilities of the abnormal category will determine how reliably DERs can maintain generation during bulk-electric grid disturbances. Thus, as applicable, states should consult and collaborate with their Regional Reliability Coordinator and RTO, ISO or transmission operator when making decisions regarding the abnormal category. For the Standard to simultaneously be technology neutral and enable high penetration of DERs, different categories allow for different levels of performance. For example:

    - Category I is intended for certain types of DERs which are expected to remain at lower penetration on the grid (e.g., flywheel storage) or are not capable of higher performance but provide some societal benefits (e.g., combined heat and power).
    - Category II is intended to allow for protective settings similar to IEEE Std 1547™-2003, while still requiring sufficient performance capability to address the bulk electric system and reliability issues arising from increasing DER penetration, as well as distribution-level events such as Fault-Induced Delayed Voltage Recovery (FIDVR) to a certain extent.
    - Category III is intended to address very high DER penetration and distribution reliability issues, including adjacent feeder faults and more extreme FIDVR, in addition to bulk-system reliability. Category III offers the highest level of ride-through capability but does not allow for business-as-usual protective settings such as IEEE Std 1547™-2003 (due to limited ranges of adjustable settings).

One consideration for regulators is whether and to what extent customers should be informed regarding this potential reduction in active power and what potential compensation or other protections should be required as a result.

In addition to ride-through capability, the abnormal category contains a default *frequency-droop* (a.k.a. *frequency-power*) function which must not be disabled.[17] The default setting for frequency droop requires active power reduction from DERs when the frequency of the grid is above 60.036 Hz, and active power increase—to the extent possible, depending on DER power output—when frequency is below 59.964 Hz.

Automatic adjustments to active power output (in order to maintain normal frequency) may result in DER customers experiencing reductions in their generation, at times, which could potentially result in a reduced return on their investment, depending on if and how their generation is compensated.[18] As such, one consideration for regulators is whether and to what extent customers should be informed in advance of this potential reduction in active power and what potential compensation or other protections should be required as a result.[19] How energy losses will be accounted for and tracked matters and can help inform the discussion on consumer protections. As a starting point for tracking this data, utilities should have the ability to estimate energy losses over time using internal system frequency data. However, other means may be necessary to accurately assess the magnitude and regularity of energy losses incurred by DER customers.

Changing the category assignment for a DER *after* it has been interconnected to the grid poses potential challenges that should be duly considered in the process to adopt IEEE Std 1547™-2018. While changing DER settings to a different value than originally specified may be technically possible, it may not be done efficiently without widespread communications infrastructure in place. In addition, DER technologies that are certified to a lower performance category may not be configured with the full range of capabilities and would be unable to shift to operate in compliance of higher performance categories. For this reason, the category assignment and performance capability levels within each and applicability for different DER technologies should be given careful consideration at the outset of the Standard's adoption efforts. Note that DERs that are certified to a higher performance category can, in most cases, meet the requirements of a lower performance category.

17 The requirements are consistent with FERC Order No. 842. Distribution utilities are discouraged from desensitizing the frequency-droop function by specifying a frequency dead band much wider than the default setting of 36 mHz.

18 The frequency of the grid on the mainland of the United States is quite stable, and thus any resulting reductions in generation should be, for most customers, *de minimis*.

19 It should be noted that the three major interconnections (Eastern, Western and ERCOT) in the U.S. have not ventured outside the stated limits with any regularity in the past.

B. Voltage Regulation Functions

Historically, DERs have not been required to support *voltage regulation*[20]. However, substantially higher volumes of DER on certain circuits can potentially cause the voltage of the grid to be affected, which could negatively impact power quality if not managed. As such, one of the major reasons for updating IEEE 1547 was to explicitly require DERs to be capable of participating in voltage regulation. It is important to note that other factors outside of DERs can impact voltage on the grid, including: a utility's voltage regulation practices, feeder design, and other DERs on the system. Different locations on a circuit will have different voltage regardless of the presence of a DER, with locations nearer to a substation or voltage regulation device generally having higher voltage, and locations further away having lower voltage.

Notwithstanding these external factors, according to IEEE Std 1547™-2018, states and utilities need to determine if and when voltage regulation functions should be turned on, which function should be utilized, and which settings should be used.[21] As previously noted, voltage regulation is *disabled* by default, so careful consideration should be given to determine what mode is desired.

Within IEEE Std 1547™-2018, there are several functions that may be activated in order to regulate voltage, and thus help mitigate any negative impacts on the grid. IEEE Std 1547™-2018 provides defaults and adjustable ranges for each of the voltage regulation functional settings, to the extent they are enabled.[22] Each of these functions interact with the grid differently and have differing impacts on the generation output of DERs. It should also be noted that the effectiveness of the reactive power functions depends on the characteristics of the circuit to which the DER is connected, so some variance in settings based on location may be desirable.[23]

One of the major reasons for updating IEEE 1547 was to explicitly require DERs to be capable of participating in voltage regulation. According to IEEE Std 1547™-2018, states and utilities need to determine if and when voltage regulation functions should be turned on, which function should be utilized, and which settings should be used.

20 The intentional adjustment of voltage with the goal of maintaining it within the normal range.

21 See IEEE Std 1547™-2018, clause 5.

22 The standard also prescribes "reactive power priority" over less effective "active power priority," the latter of which was utilized in California's interconnection rules (Rule 21).

23 For instance, the reference voltage for the volt-var function, Vref, could be chosen based on circuit location.

The following are reactive power functions defined within IEEE Std 1547™-2018 that affect voltage:

- **Constant power factor mode**:[24] In this mode, the power factor—which is the ratio of *active power* (a.k.a. real power or true power)[25] to *apparent power*[26]—is set to the desired value and remains the same, even as the power output from the DER fluctuates. It can be set to either absorb or inject reactive power. Absorbing reactive power tends to decrease voltage, while injecting reactive power tends to increase voltage. Of note, constant power factor is the default mode for voltage regulation in IEEE Std 1547™-2018 and the default setting is 1.0 (unity), which *does not* provide voltage regulation. Typical power factor settings that are useful for voltage regulation are 0.95 - 0.98 absorbing. Category A DERs can reach 0.97 absorbing, while Category B DERs can reach 0.90 absorbing.
- **Voltage-reactive power mode** *(a.k.a. volt-var)*: In this mode, the DER modulates its absorption or injection of reactive power in relation to the measured grid voltage. There can be a "dead band" near normal voltage where no reactive power is absorbed or injected. Values for the gain (or droop) setting of the function other than the default values must be carefully chosen because a high gain (small droop) value may cause the control to become unstable while a low gain (high droop) may be ineffective.
- **Active power-reactive power mode** (a.k.a. watt-var): In this mode, the DER modulates its absorption or injection of reactive power in relation to its active power output (and absorption of active power for DERs that can store energy).
- **Constant reactive power mode**: In this mode, the DER absorbs or injects a specified amount of reactive power regardless of its active power level (i.e., reactive power remains constant as power output from the DER fluctuates).

Of note, in addition to the reactive power functions, there is a mode that utilizes a reduction in active power to decrease voltage (normally only once voltage is outside of the normal range, or ANSI C84.1 range A). This mode is known as *voltage-active power mode* (a.k.a. *volt-watt*).

Of the above reactive power functions, the IEEE Std 1547™-2018 default is the constant power factor mode, with a setting of "unity" (i.e., no reactive power). Therefore, no voltage support nor its benefits will be realized with the IEEE Std 1547™-2018 default settings. States and utilities seeking to enable and utilize voltage regulation functions will want to clarify in rules which voltage regulation function DERs should utilize and adjust from IEEE Std 1547™-2018 defaults accordingly. Only one of the four reactive power functions can be activated at a time for an individual DER, while volt-watt may be activated independently of the reactive power functions.

24 This is also expressed as the cosine of phi (cos), the phase angle between the current and voltage waveforms, which is more technically correct than "power factor."

25 Active power does the actual work in the load. Active power is measured in watts (W) and is the power consumed by electrical resistance.

26 Apparent power is the combination of reactive power and active power. Apparent power is the product of a circuit's voltage and current, without reference to phase angle, and is measured in volt-amperes (VA).

States and utilities seeking to enable and utilize voltage regulation functions will want to clarify in rules which voltage regulation function DERs should utilize and adjust from IEEE Std 1547™-2018 defaults accordingly.

Constant power factor mode, watt-var mode, and constant reactive power mode all have largely predictable effects on both the distribution grid and on DER generation. All three modes will cause *var flow*[27], regardless of whether var flow is needed to regulate voltage. Excessive var flow reduces the efficiency of power delivery and reduces the active power capacity of a circuit. The volt-var mode aims to proportionately increase reactive power as voltage gets further from normal, thus reducing or eliminating var flow on the circuit when it is not needed. The default settings for volt-var (including response time) in IEEE Std 1547™-2018 are meant to be applicable in a wide range of scenarios where nominal voltage[28] is desired.

Individual DERs may interact more beneficially with the distribution system if the volt-var function's reference voltage (a.k.a. V_{ref})[29] is adjusted for the particular location on the circuit, which would require the utility to convey the proper value or mode during the interconnection process via the utility-required profile. Should utilities wish to conduct a more detailed study to ensure a DER does not interact with other distribution system components in an undesirable manner, existing power flow tools should be able to model the impacts of volt-var functions.

When considering the adoption of voltage regulation functions, states and utilities should keep in mind their interaction with interconnection procedures and how these functions might impact whether a grid upgrade might be necessary to connect the DER to the grid. As DER penetration on the grid increases, enabling voltage regulation functions might allow certain DERs to connect to locations on the grid where previously they might not have been able to (i.e., without triggering a grid upgrade or a modification to the DER project to mitigate voltage impacts). Similarly, voltage regulation functions have the ability to increase the DER hosting capacity of a circuit, and thus should be accounted for in any formal hosting capacity analysis effort going forward.[30] As states and utilities proceed with DER hosting capacity analyses, the methodology should be refined to reflect the impact of default voltage regulation settings on hosting capacity values. The reactive power demand of DERs may also have impacts on the distribution system that need to be accounted for.[31]

27 Var flow is the presence of reactive power on the distribution grid conductors and equipment. Though it does not deliver active power, it still causes heating effects on the conductors.

28 Nominal voltage is 120V on a 120V base. Generally, it is the center of the normal service voltage range specified by ANSI C84.1 range A.

29 A specific value for Vref can be set, or alternatively can be autonomously calculated by the DER based on local measurement.

30 Hosting Capacity is the amount of DERs that can be accommodated on the distribution system under existing grid conditions and operations without adversely impacting operational criteria or requiring significant infrastructure upgrades. For more information about hosting capacity analyses, see IREC's *Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources*, available for free download at: *https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/*.

31 Such impacts include the ability of the substation or transmission system to supply vars necessary to support the reactive power requirements of the DERs, and the reduction of active power capacity of conductors.

Voltage regulation has the possibility of reducing the generation output of certain DERs. For example, inverters may be "current-limited" at maximum rated power, especially those used for residential DERs.[32] Any requirement for the inverter to produce reactive power would cause a decrease in the maximum active power available. Additionally, the volt-watt function has the potential to drastically reduce active power and could contribute to major generation losses, if triggered regularly. At this juncture, it is challenging to predict how voltage-dependent functions (e.g., volt-var and volt-watt) will affect generation over the lifetime of the DER, especially since the voltage of a circuit is time-varying and could change over the course of several years.

To address potential impacts on DER customers resulting from the implementation of voltage regulation functions, regulators may want to consider adopting some consumer protection measures. To begin with, states and utilities can establish reporting procedures to track customer generation losses resulting from the utilization of voltage regulation functions, which can help regulators determine the scale and frequency of customer impacts over time. Regulators should consider clarifying the following issues to help inform the adoption of customer protection measures in the future:

- **Guidelines for tracking and reporting any customer generation losses;**
- **Methods and techniques for estimating losses and/or the extent of voltage excursions;**
- **Regular utility reporting, filed with the utility commission, of when, where, how often voltage regulation functions are utilized;**
- **Identification and consideration of possible corrective measures in the event losses are deemed excessive or unwarranted (e.g., DER settings adjustments, monetary reimbursement, etc.).**

In considering the consumer impacts of voltage regulation functions, regulators should aim to strike the appropriate balance of optimizing the functionality for the benefit of the grid and customers, while minimizing negative impacts on the economic value of an individual customer's investment.

Lastly, it is important to note that voltage regulation functions on the distribution system are optimized, particularly at higher DER penetration, if all or most of the DER systems are participating in voltage regulation. Implementing voltage regulation only for new DERs after higher DER penetration has been achieved may dramatically reduce the effectiveness of this function. In addition, such late-stage adoption of voltage regulation functions may disproportionately affect new DER customers seeking to connect to the grid after a significant amount of non-voltage regulating DER projects are connected. Hawaii, for example, learned that the grid would have been able to host higher penetration of DERs if they had been able to deploy these functions early on.[33]

32 For any active power level, reactive power production requires more current from the inverter. If all available current is being used to produce active power (i.e. at maximum active power) and the inverter is called on to produce reactive power, it must reduce active power so that some current capability can be utilized to provide the required reactive power. Some inverters have an apparent power (kVA) rating larger than the active power (kW) rating, allowing them to supply some reactive current even at maximum active power output. Since residential inverters are often connected on the load side of a customer's load center or panelboard, the maximum inverter current is limited by the circuit breaker used, per National Electrical Code rules. Depending on the size of the breaker and panelboard bus, it could be undesirable to utilize an inverter with a kVA rating higher than the kW rating.

33 Giraldez, Julieta, et al., *Simulation of Hawaiian Electric Companies Feeder Operations with Advanced Inverters and Analysis of Annual Photovoltaic Energy Curtailment*, National Renewable Energy Laboratory and Hawaiian Electric Company, pp. 80-82, September 2017, available at: *https://www.nrel.gov/docs/fy17osti/68681.pdf.*

C. Communications, Controls & Interoperability

All the grid supportive functionality mentioned thus far can operate autonomously, by simply reacting to local measurements of voltage or frequency, as necessary. The autonomous functions are a large step in the direction of effectively integrating DERs into the grid. However, the eventual adoption of communications and controls will be key to unlocking the full potential of DERs on the grid. A key feature of IEEE Std 1547™-2018 is the requirement for DERs to include provisions for a local DER communication interface, with a minimum set of communications capabilities which could allow even more benefits to be realized, as well as allowing settings to be adjusted over time.

State interconnection rules (and in some cases utility interconnection handbooks or guidance documents) will need to specify which DERs will be required to integrate with communications systems (e.g., DERs that meet a certain kVA threshold), and what communications protocol the utilities will use at the DER communication interface. Ideally, there would be requirements for consistency across utilities, where possible, in order to minimize costs and confusion in the marketplace. Additionally, consideration should be given as to whether or not a particular physical communications port should be available at the DER.[34] Since communications services can be also be provided by third-party aggregators that control numerous DERs, requirements or agreements that address the aggregator relationships to the DER owner and the utility should also be considered. Lastly, additional consideration should be given to when and how utilities utilize these communications functions to control DER functionality, which may impact the operation of the DER. States and utilities should be specific about the conditions under which DERs may be remotely curtailed, turned off, and/or when changes to certain settings or functions may be warranted. Any controls that affect DER generation will have consumer protection implications (as noted above) that will need to be proactively addressed and documented in interconnection agreements.

States and utilities should be specific about the conditions under which DERs may be remotely curtailed, turned off, and/or when changes to certain settings or functions may be warranted.

34 IEEE Std 1547™-2018 standardizes the use of an Ethernet port with TCP/IP transport layer for any of the three protocols, with an option for an RS-485 port for SunSpec Modbus.

IEEE Std 1547™-2018 requires all categories of DERs to support at least one of three communication protocols through a specified local DER communication interface: IEEE Std 2030.5™ (SEP2), IEEE Std 1815™ (DNP3), or SunSpec Modbus.[35] IEEE Std 1547™-2018 also requires DERs to support specific parameters for monitoring information and for managing functional settings (including protection and controls). In the absence of communications infrastructure, access to the settings of the DER must be available through a hardware or software panel on site. Of note, given the inherent challenge of adjusting these settings after a DER has been commissioned (an in-person visit to the DER location would likely be necessary), it is important to adopt settings that will not likely require adjustment after commissioning.

Traditionally, larger DER projects and/or those with special interconnection agreements (e.g., DERs participating in wholesale markets) have been required to have communications and controls enabled in order to interface with the grid operators. However, these technical capabilities have not yet been standardized. Over time, it is expected that the communication protocols will continue to harmonize and be capable of communicating across different networks and between technologies that have distinct settings (a.k.a. *interoperability*[36]). These updated requirements for communications and interoperability will help optimize DERs on the grid and improve safety and reliability. Transitioning to IEEE Std 1547™-2018 compliant local DER communications interfaces will require time for widespread deployment of communications infrastructure by grid operators or third parties, and consideration of related issues, including cybersecurity and standardization of communication network performance requirements.[37]

The ease and cost of implementing new communication protocols will be highly dependent on the availability of existing infrastructure and a utility's existing capabilities. For states where the utility may have outdated or inefficient communications systems, regulators will need to carefully consider the cost impact (to all ratepayers and/or to individual DER customers) of updating and/or revamping existing systems to allow for more sophisticated communications to occur with DERs in order to utilize the IEEE Std 1547™-2018 required capabilities. To ensure transparency and alignment with IEEE Std 1547™-2018, states may want to evaluate the deployment of communications and controls infrastructure in the context of existing or planned Smart Grid, Grid Modernization, Distribution Resource Plan, and/or Integrated Resource Plan proceedings.

35 IEEE Std 2030.5™ is the IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard; IEEE Std 1815™ is the IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3); SunSpec Modbus is a standard that defines a set of common register values for devices such as three-phase inverters, single-phase inverters, meters, environmental units, and related measurement devices, see *https://sunspec.org* for more information.

36 See IEEE Std 1547™-2018, clause 10.

37 Performance or cybersecurity requirements related to DER management networks are outside the scope of IEEE Std 1547™-2018.

D. Power Quality

IEEE Std 1547™-2018 introduces new limits for rapid voltage changes, flicker and overvoltage—all of which relate to power quality.[38] In addition, the Standard alters and clarifies harmonic distortion limits. These requirements ensure that other utility customers located on the same circuit as a DER, as well as the utility equipment, are not negatively affected. These requirements pertain to all categories without any optionality, so no decisions need be made regarding their application within interconnection rules. References or requirements for power quality in existing interconnection rules or utility handbooks should be updated to align with these new IEEE Std 1547™-2018 provisions.

The overvoltage limits in IEEE Std 1547™-2018 ensure that DER complies with *effective grounding* requirements.[39] These limits, along with compliance tests in IEEE Std 1547.1™, will help to clarify if and when grounding banks or grounding transformers are needed to limit *ground fault overvoltage*.[40] While equipment requirements for effective grounding for rotating machines are commonplace, recent research has shown that inverter-based DERs do not have similar responses in terms of overvoltage events.[41] IEEE Std C62.92.6™-2017[42] helps explain the concepts of inverter response and how grounding does or does not affect overvoltage. Whether effective grounding requirements are addressed in a state or utility's interconnection rules or not, it may be prudent to review utility practices in order to ensure that excessive grounding is not required for DERs and that DER customers do not bear the cost and time burden associated with unnecessary equipment.

The overvoltage limit in IEEE Std 1547™-2018 also addresses another effect known as *load rejection overvoltage*. In the scenario where a circuit breaker or other device initiates an island condition,[43] cutting off a portion of the load to which a DER was initially providing power, there is insufficient load available to consume the DER power being fed onto the grid. This results in an overvoltage situation called load rejection overvoltage. Historically, concerns over load rejection overvoltage have led utilities to limit DER penetration or take other conservative actions to prevent damage to other customers' or the utility's equipment. Initial research on inverter load rejection overvoltage response conducted by NREL noted "over-voltages were less severe than some observers had feared and have allayed some utility concerns."[44] Hawaiian Electric has required load rejection test data for inverters for several years. IEEE Std 1547.1™ will require similar testing and the DER must remain within the stated limits of IEEE Std 1547™-2018. This, in turn, will impact interconnection studies and the technical screening process for DERs seeking to connect to the grid. As such, states and utilities will need to address how interconnection requirements might change in light of these new mandatory limits that all DERs will be subject to once IEEE Std 1547™-2018 is fully rolled out.

38 See IEEE Std 1547™-2018, clause 7.

39 Effectively grounded systems limit overvoltage to 139% of nominal.

40 Single line to ground faults on a system that has lost its ground reference, where a breaker has opened and before DER disconnects or ceases production, can potentially cause large overvoltages on the order of 173% of nominal.

41 Hoke, Andy, et al., *Inverter Ground Fault Overvoltage Testing*, National Renewable Energy Laboratory and SolarCity Corporation, August 2015, available at: *https://www.nrel.gov/docs/fy15osti/64173.pdf*.

42 Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI- Systems Supplied by Current-Regulated Sources.

43 Islanding is the condition in which a distributed generator continues to power a portion of a circuit even though power from the electrical grid is no longer present.

44 Nelson, Austin, et al., *Inverter Load Rejection Over-Voltage Testing*, National Renewable Energy Laboratory and SolarCity Corporation, February 2015, available at: ***https://www.nrel.gov/docs/fy15osti/63510.pdf***.

E. Islanding

Requirements for a DER to avoid unintentional islanding[45] remain mostly unchanged in IEEE Std 1547™-2018, however certain provisions have been modified.[46] For example, according to the Standard, the time limit (a.k.a. *clearing time*) for DERs to detect islands and cease energization may be extended from the current 2 seconds up to 5 seconds, by mutual agreement of the utility and the DER customer. In cases where risk of islanding for longer than 2 seconds is an identified possibility, this longer time may allow anti-islanding methods to operate or for the voltage to collapse on its own, eliminating the island. The 5 second time limit may require that any recloser upstream of the DER also have sufficiently long reclose time (i.e., greater than the DER clearing time or greater than the time at which the island would collapse). Another option is to use voltage-permissive reclosing, where the reclose is blocked if an island is present on the isolated feeder section. Where it can be determined that an increased DER clearing time can be utilized without negatively affecting safety and reliability, recloser settings can be coordinated to accommodate DER connection that may otherwise be subject to *Direct Transfer Trip* (DTT)[47] or other costly upgrades. The benefit of this increase in DER clearing time would apply to all DER downstream of the relevant recloser, though it may only initially be proposed as a mitigation strategy for a single DER (or group of DERs) that may be at risk of having to go through a costly or time-intensive interconnection study.

IEEE Std 1547™-2018 also addresses, to a more limited extent, intentional islands (a.k.a. *microgrids*) that are fully behind the PCC[48] (a.k.a *intentional Local Electric Power System (EPS) island*) or that include a portion of the Area EPS (a.k.a *intentional Area EPS island*). Intentional Area EPS islands, sometimes called "utility microgrids," could include DERs from multiple owners, load-only customers and utility equipment. IEEE Std 1547™-2018 specifies special requirements for DERs that participate in intentional Area EPS islands. Utilization of such capabilities is subject to mutual agreement with the DER owner and the utility.

The Standard gives special exemptions to DERs in intentional islands from the ride-through performance and trip requirements and allows them to disconnect from the grid and form an island as long as certain power balance criteria are met.

As states, communities and utilities seek to improve and enhance grid resilience and reliability, especially during inclement weather or severe electric system disruptions, adopting state regulations and standards surrounding intentional islands can provide important clarity for how these islands interact with and function on the existing grid. For example, it may be prudent to include some language in state and utility interconnection requirements to make it clear that such intentional islands are explicitly allowed and subject to certain appropriate technical requirements.

45 Islanding is the condition in which a distributed generator continues to power a portion of a circuit even though power from the electrical grid is no longer present.

46 See IEEE Std 1547™-2018, clause 8.

47 DTT usually consists of a fast communications link from breakers or reclosers upstream of the DER to a relay at the DER location which can disconnect the DER whenever the upstream devices disconnect. These are generally bespoke solutions that can include new telephone wire or other communications channels to be put in place, as well as additional equipment or adjustments at the utility device and DER locations.

48 Point of Common Coupling (the point of connection between the DER customer and the utility, typically at the utility revenue meter).

F. Secondary Network Distribution Systems

IEEE Std 1547™-2018 clarifies the provisions for meeting operational requirements for DERs interconnecting to secondary spot networks and secondary grid networks.[49] Any existing language in interconnection rules addressing network interconnection may need updating based on the new Standard. However, the additional requirements are more akin to secondary networks design and DER operations considerations and do not alter requirements from IEEE Std 1547™-2003. The new language does allow DERs to be connected to Area Networks, where that was not addressed in the earlier Standard. IEEE Std 1547.6™ provides more explanation on recommended practices.

G. Fault Current

Operators of electronically coupled (i.e., inverter-based) DERs with an aggregate rating of 500 kVA and larger are required by IEEE Std 1547™-2018 to provide the utility with detailed voltage and current data for faults obtained during certification testing.[50] No additional changes to the interconnection process are likely necessary, beyond specifying this data requirement. However, as this data is collected over time, attention should be paid as to whether changes to the interconnection processes are warranted based on the utilities' evolving understanding of inverter fault current.

As states, communities and utilities seek to improve and enhance grid resilience and reliability, adopting state regulations and standards surrounding intentional islands can provide important clarity for how these islands interact with and function on the existing grid.

49 See IEEE Std 1547™-2018, clause 9.

50 See IEEE Std 1547™-2018, subclause 11.4.

H. System Controls and Power Limitation at the PCC

IEEE Std 1547™-2018 implies that certain export control systems can be used to prevent DERs from exporting onto the grid beyond designated specifications (e.g., for DERs that are designed to be non-exporting[51] or limited exporting[52]).[53] However, the Standard does not give specific guidance on how these system controls should be implemented. As such, further definition of related requirements may be prudent to include in interconnection rules to address these systems.

For example, IEEE Std 1547™-2018 notes that the reference point of applicability may be determined based on whether or not the DER is prevented from exporting power more than 500 kVA for longer than 30 seconds. This implies that a DER may include a plant controller that measures export power and controls the DER units to serve on-site load, while ensuring a specific power limit is not exceeded. Similar controls may be used to implement the volt-watt function, such that on-site load can be served even when voltage is high. The concept might also be extended to the limit active power function, where an external control demands power export reduction. Furthermore, a DER system may also include export-limiting controls in order to comply with other relevant compensation policies pertaining to exported or excess generation (e.g., net energy metering).

As another option to control the output of a DER, IEEE Std 1547™-2018 allows for the possibility of a "configured" nameplate rating[54] to be used. This relatively new concept would allow for the use of a configuration setting to limit the nameplate capacity of the DER to a lower capacity than its actual nameplate capacity, and this setting would effectively prevent the DER from exporting power beyond the configured nameplate rating at the reference point of applicability (e.g., the PoC).

One important consideration in the discussion surrounding limiting power export and system controls is the concept of inadvertent export.

51 DER systems primarily designed to serve on-site customer load that never or rarely export energy onto the grid.

52 DER systems designed to never or rarely export energy beyond a certain limited power level.

53 See IEEE Std 1547™-2018, subclauses 4.2, 4.6.2 and 5.4.2 footnote 65.

54 See IEEE Std 1547™-2018, subclause 10.4

While the Standard does not specify the details of using this setting, a state or utility's interconnection rules could define and allow for this as an option for system control. Alternatively, or in addition, the details could be determined and defined through mutual agreement between the utility and the DER customer (likely via the interconnection agreement).

One important consideration in the discussion surrounding limiting power export and system controls is the concept of *inadvertent export*[55], which occurs when power higher than the specified limit may incidentally be exported onto the grid for short periods of time. Introducing and defining this concept in state interconnection rules may be important to allow for limited-export and non-exporting DERs to be sufficiently addressed, namely in the context of interconnection standards. Similar requirements that include the concept of inadvertent export have been introduced in interconnection rules in Hawaii, California, Nevada[56] and elsewhere in relation to non-exporting systems. Consideration should be given to how the application of inadvertent export and export limitations impact interconnection eligibility and how technical screens are applied. This is an evolving area of discussion and applicable requirements and testing standards for controls are still under development.

55 When non-exporting or limited-export DERs inadvertently export limited amounts of power for very short durations, it is typically due to transient mismatch between system output and load consumption (when unanticipated load fluctuations occur). This can occur for customers whose systems are sized to closely match their load, or those with larger loads that may abruptly turn off while being supplied by the DER system. Importantly, inadvertent export is different from "islanding".

56 For instance, Hawaiian Electric Rule 22, Appendix II; PG&E Rule 21, section Mm; and NV Energy Rule 15, section I.4.b.

VI. Other Key Issues for Consideration

As states work to adopt and implement IEEE Std 1547™-2018, the following overarching policy issues warrant careful consideration:

- **Opportunities and Impacts of Frequency and Voltage Regulation**: Utilization of frequency regulation and DER design for improved power quality will be *required by default* in IEEE Std 1547™-2018. However, voltage-regulating functions are *not required to be turned on by default*. To make the most of the Standard and prepare for higher DER penetration in the future, regulators and utilities should consider the opportunity to utilize voltage regulation functions *before* achieving higher penetration of DERs. Reaching high penetration *before* implementing these functions can limit their effectiveness to increase the grid's hosting capacity for more DER over the long-term.

- **Consumer Impacts and Protections**: Utilizing IEEE Std 1547™-2018 enabled functions can (dependent on the settings) reduce a DER system's generation at certain locations, which can impact a consumer's investment and project economics. Care must be taken to ensure customers are not unduly affected by the required settings. Since the performance of voltage regulation functions depend on a customer's location on the grid as well as factors outside of the customer's control, such as utility voltage regulation practices, introducing these functions may complicate system performance modeling and potentially reduce a consumer's expected return on investment. Adopting explicit consumer protection provisions may be necessary to ensure that customers are aware of any potential loss of generation over time and/or that recourse exists to the extent a single customer experiences a disproportionate amount of generation loss. Similarly, DER system designers need to understand and model the effects of the new functions on DER output power to convey accurate information to customers regarding anticipated lifetime generation.

Utilizing IEEE Std 1547™-2018 enabled functions can (dependent on the settings) reduce a DER system's generation at certain locations, which can impact a consumer's investment and project economics.

- **Updates to State Interconnection Procedures and Protocols**: The adoption and integration of IEEE Std 1547™-2018 into state and utility interconnection procedures will impact the review process for all DER, and states should work to ensure as much consistency and harmonization as possible among the different utilities within their jurisdiction. State public service commissions can set forth "preferred" IEEE Std 1547™-2018 settings that apply to all regulated utilities in the state, which will help ensure greater consistency across service territories and increased clarity for stakeholders navigating the interconnection process. Enabling advanced functions for DERs will also help ensure a smoother glidepath to adopt and integrate more DERs on the grid over time. In certain situations, individualized site-specific settings may be a viable option for DER customers seeking to interconnect in lieu of an identified grid upgrade. However, state interconnection rules will need to provide clarity around the circumstances under which this can occur to maintain a fair and equitable process for all DER customers.

- **Requirements for DER System Modifications and Maintenance**: As DER system components require maintenance or replacement over time, states should address how these upgrades will be handled in the context of IEEE Std 1547™-2018. Such system upgrades are often dealt with through interconnection procedures, sometimes referred to as *material modifications*[57]. IEEE Std 1547™-2018 acknowledges that "substitutive components" compliant and tested to the Standard may be used as replacements without invalidating certification testing. Field demonstration or commissioning tests may still be required to confirm proper operation and settings of the DER after the equipment is updated. Clear guidance in interconnection rules on these requirements will ensure that existing DERs can be cost-effectively maintained over time.

States should work to ensure as much consistency and harmonization as possible among the different utilities within their jurisdiction.

57 A change to a DER system that impacts its operational characteristics.

VII. Conclusion: State Leadership to Implement IEEE Std 1547™-2018

The rules governing the grid have been evolving for many years and will continue to evolve as more DERs are integrated and optimized as resources. With IEEE Std 1547™-2018 published and a few remaining years before full rollout, now is the time for states and regulators to begin to implement the updated Standard. The optionality included in the new Standard will require thorough discussion of the technical, process and consumer impacts of adopting the new Standard. The Standard will not only affect DER customers, developers, and utilities, but project financiers and investors. There are additional issues outside the scope of this primer that will need to be addressed in addition to those directly related to adoption of the Standard. Stakeholder engagement and thoughtful navigation of the process will help ensure a smooth and transparent transition from old to new grid paradigms. States that work swiftly to address the new Standard will be better equipped to integrate new technologies, optimize the benefits of DERs, and improve system power quality. Even states that may not expect a significant increase in DER interconnections over the next decade, can ensure adequate DER capabilities by adopting IEEE Std 1547™-2018. Now is the time to commence the process and pave the path for a more distributed and clean energy future.

States that work swiftly to address the new Standard will be better equipped to integrate new technologies, optimize the benefits of DER, and improve system power quality.

VIII. Key Acronyms

ANSI	American National Standards Institute
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DTT	Direct Transfer Trip
EPRI	Electric Power Research Institute
EPS	Electric Power System
FERC	Federal Energy Regulatory Commission
FIDVR	Fault-Induced Delayed Voltage Recovery
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
kVA	kilovolt-ampere (measure of apparent power in an electrical circuit)
NREL	National Renewable Energy Laboratory
PCC	Point of Common Coupling
PoC	Point of DER Connection
PV	Photovoltaic
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
SGIP	Small Generator Interconnection Procedures
UL	Underwriters Laboratories

IX. Key Codes & Standards

ANSI C84.1	American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hz). "ANSI C84.1 Range A" refers to the normal service voltage range for the U.S. electric grid
IEEE Std 1547™-2003	IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems
IEEE Std 1547™-2018	IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces
IEEE Std 1547.1™	IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
IEEE Std 1815™	IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol
IEEE Std 2030.5™	IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard
SunSpec Modbus	A standard that defines a set of common register values for devices such as three-phase inverters, single-phase inverters, meters, environmental units, and related measurement devices
UL 1741	Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources

X. Key Terms

Abnormal Operating Performance Category – Specifies DER performance during a grid voltage or frequency disturbance such as a transmission fault or loss of a generator.

Active power – The real power consumed by electrical resistance; measured in watts.

Active power-reactive power mode (watt-var) – In this mode, the DER modulates its absorption or injection of reactive power in relation to its active power output (and absorption of active power for DERs that can store energy).

Apparent power – The combination of reactive power and active power; measured in volt-amperes, it is the product of a circuit›s voltage and current, without reference to phase angle.

Area Electric Power System – The electric power distribution and delivery system that includes facilities typically owned by a utility.

Clearing time – The time limit for DERs to detect a condition which requires tripping (such as an island) and cease energization.

Commissioning testing – The evaluation of a DER system after installation but before final energization to inspect the system and verify that it was installed properly and to confirm that it functions as designed.

Constant power factor mode – Mode in which power factor is set to the desired value and remains the same, even as the power output from the DER fluctuates.

Constant reactive power mode – In this mode, the DER absorbs or injects a specified amount of reactive power regardless of its active power level (i.e., reactive power remains constant as power output from the DER fluctuates).

Effective grounding – Limits the fault current via neutral connections to ground, grounding banks or reactors to allow a limited and safer amount of overvoltage; effectively grounded systems limit overvoltage to 139% of nominal.

Evaluation – The review of the design of the DER system and/or a review of the "as-built" DER system, typically performed by a utility engineer.

Fault current – An abnormal electric current between conductors or conductors and ground, typically due to physical contact.

Flicker – The changing light intensity (e.g., a change in brightness from a lamp) caused by voltage fluctuations.

Frequency regulation – The adjustment of active power input during temporary frequency disturbances; also referred to as "frequency-droop" or "frequency-power" when in relation to DER.

Frequency-droop – See "frequency regulation."

Ground fault overvoltage – A phenomenon that occurs when a single line faults to ground on a system that has lost its ground reference, where a breaker has opened and before DER disconnects or ceases production, which can potentially cause large transient or temporary overvoltages on the order of 173% of nominal.

Hosting capacity – The amount of DERs that can be accommodated on the distribution system under existing grid conditions and operations without adversely impacting operational criteria or requiring significant infrastructure upgrades.

Inadvertent export – The unscheduled export of power onto the grid from non-exporting or limited-export DERs; it is typically due to transient mismatch between system output and load consumption (when unanticipated load fluctuations occur) and lasts for very short durations.

Intentional Area Electric Power System Island – A microgrid that includes a portion of the Area Electric Power System.

Intentional Local Electric Power System Island – A microgrid that is fully behind the point of common coupling.

Interconnection rules – Regulations that govern the processes required for generating facilities to connect to the grid; also called "interconnection standards" or "interconnection procedures."

Key Terms continued

Interoperability – The capability of two or more different systems, networks or technologies to communicate and exchange information.

Islanding – The condition in which a distributed generator continues to power a portion of a circuit even though power from the electrical grid is no longer present.

Limited-export system – A DER system designed to never or rarely export energy beyond a certain limited power level.

Load rejection overvoltage – A transient condition that results from a situation in which there is insufficient load available to consume the DER power being fed onto the grid.

Local Electric Power System – The electric power system that typically includes only customer power delivery facilities and load on the load side of the point of common coupling.

Material modification – Change to a DER system that impacts its operational characteristics.

Microgrid – A localized power grid that can operate independently from the traditional grid through the use of intentional islanding.

Nameplate capacity – The maximum output of a generator as determined by the manufacturer; also referred to as "rated capacity" or "nominal capacity."

Nominal voltage – The center of the normal service voltage range specified by ANSI C84.1 range A.

Non-exporting system – A DER system primarily designed to serve on-site customer load that, while connected in parallel, never or rarely exports energy onto the grid.

Normal Operating Performance Category – Specifies how a DER should perform with regards to voltage control during normal grid operations.

Point of Common Coupling – The point of connection between the DER customer and the utility, typically at the utility revenue meter.

Power factor – Ratio of active power to apparent power.

Power quality – The relative frequency and severity of deviations in power supplied to consumer equipment; voltage changes, flicker and harmonics can impact power quality.

Reactive power – Measured in vars, it is power that does not do work, but is stored or returned to the circuit every half cycle; reactive power results whenever the voltage and current waveforms are shifted in time relative to one another, rather than being aligned.

Reference point of applicability – The physical point on the electric grid where compliance with the Standard's requirements will be assessed.

Ride-through capability – The capability of a DER to continue operating (i.e., not trip) during abnormal frequency and voltage events (i.e., significantly high or low voltage or frequency).

Secondary Network Distribution Systems – An AC power distribution system that serves customers using low-voltage circuits supplied by two or more network transformers connected to the circuits through network protectors.

Unity – A DER power factor setting that allows no reactive power and does not provide voltage regulation.

Var flow – The presence of reactive power on the distribution grid conductors and equipment; though it does not deliver active power, it still causes heating effects on the conductors, reducing active power delivery capacity.

Voltage – The difference in electrical potential measured in volts.

Voltage regulation – The intentional adjustment of voltage with the goal of maintaining it within the normal range.

Voltage-active power mode (volt-watt) – This mode utilizes a reduction in active power to decrease voltage (normally only once voltage is outside of the normal, or ANSI C84.1 range A, range).

Voltage-reactive power mode (volt-var) – In this mode, the DER modulates its absorption or injection of reactive power in relation to the measured grid voltage; there can be a "dead band" near normal voltage where no reactive power is absorbed or injected.

XI. Additional Resources

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EXHIBIT 4

OPTIMIZING THE GRID

A REGULATOR'S GUIDE TO

Hosting Capacity Analyses for Distributed Energy Resources

IREC
Interstate Renewable Energy Council

December 2017

OPTIMIZING THE GRID

A REGULATOR'S GUIDE TO

Hosting Capacity Analyses for Distributed Energy Resources

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Acronyms and Abbreviations

API	Application Program Interface
CPUC	California Public Utilities Commission
DER	Distributed Energy Resource
DG	Distributed Generation
DOE	United States Department of Energy
DRP	Distribution Resources Plan (California)
DSIP	Distribution System Implementation Plan (New York)
EPRI	Electric Power Research Institute
GIS	Geographic Information Systems
HCA	Hosting Capacity Analysis
ICA	Integration Capacity Analysis (California)
IDP	Integrated Distribution Planning
IOU	Investor Owned Utility
IREC	Interstate Renewable Energy Council, Inc.
LNBA	Locational Net Benefits Analysis (California)
MW	Megawatt
MN PUC	Minnesota Public Utility Commission
NREL	National Renewable Energy Laboratory
NY PSC	New York Public Service Commission
PG&E	Pacific Gas & Electric
PV	Solar Photovoltaic
REV	Reforming the Energy Vision (New York)
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Company
SDSIP	Supplemental Distribution System Implementation Plan (New York)
VDER	Value of Distributed Energy Resources (New York)

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Executive Summary

From coast to coast, states are experiencing unprecedented growth in distributed energy resources (DERs) – resources located on the electric distribution system, such as renewable energy, energy efficiency and energy storage. With much of this activity being driven by consumers, changes to the nation's outdated electric system are underway. To ensure that the benefits of these DERs are fully optimized, there is a need to proactively integrate them into grid planning, operations and long-term investment decisions. Rather than simply "tolerating" DERs, there is an opportunity to utilize a new tool known as Hosting Capacity Analysis (HCA), which can help more Americans enjoy the benefits and full potential of these resources on the grid.

The term "hosting capacity" refers to the amount of DERs that can be accommodated on the distribution system at a given time and at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring significant infrastructure upgrades.

Hosting Capacity Analyses (HCAs) allow utilities, regulators and electric customers to make more efficient and cost-effective choices about deploying distributed energy resources on the grid.

HCAs allow utilities, regulators and electric customers to make more efficient and cost-effective choices about deploying DERs on the grid. If adopted with intention, HCA may also function as a bridge to span information gaps between developers, customers and utilities, thus enabling more productive grid interactions and more economical grid solutions.

Utility regulators play a key role in ensuring HCAs are deployed strategically, prudently and for the benefit of all energy customers. *Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources* will assist state regulators in guiding and overseeing utilities as they conduct hosting capacity analyses on their distribution circuits, as part of a broader grid modernization or distribution planning efforts and/or in support of their state's near- and long-term energy policy goals.

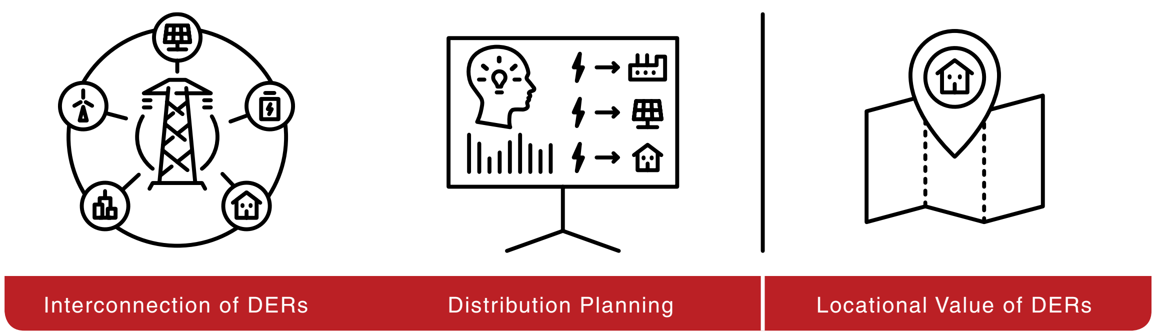
Based on lessons from the handful of states and utilities that have begun to prepare HCAs, this guide focuses on the *process* that will help regulators realize HCAs' full promise in their respective states. The experiences and key takeaways from the states and utilities undertaking these analyses, including California, New York, Minnesota, Hawaii and Pepco Holdings, Inc., provide important insights for other states and utilities to take into consideration as they pursue similar efforts. Details on each can be found in *Appendix A* of the full guide.

Hosting Capacity Analysis Use Cases

There are two principal applications, or use cases, for an HCA: 1) assist with and support the streamlined interconnection of DERs on the distribution grid; and 2) enable more robust distribution system planning efforts that ensure DERs are incorporated and reflected in future grid plans and investments. A third, complementary function of an HCA could be to inform pricing mechanisms for DERs based on separate analyses to assess the benefits of DERs based on their physical location on the grid and their performance characteristics (see Figure ES-1). To achieve an effective HCA, regulators and utilities should carefully consider and articulate their goals and use cases at the outset of an HCA effort.

Use cases can be selected to reflect the unique characteristics and identified goals of states and utilities. These use cases should inform and guide the development of an HCA methodology and its implementation. A process should also be in place to refine the selected use cases as new regulatory, social, and technological conditions emerge. The two major HCA use cases—interconnection and planning—as well as the complementary function of optimizing the locational benefits of DERs are discussed in detail in Section III of the full guide.

Figure ES-1. Hosting Capacity Use Cases



Hosting Capacity Analysis Methodologies

A well-considered methodology for determining hosting capacity is necessary given the variety of factors that affect the grid's ability to host a wide range of DERs. IREC has identified three principle categories of methodologies that are currently being tested and employed by utilities to analyze hosting capacity, generally known as the stochastic, iterative, and streamlined methods. This paper describes these methodologies, including the tradeoffs between them that may make them more or less suited to the various use cases that regulators may select. Briefly, the three methodologies are characterized as follows:

The streamlined method applies a set of simplified algorithms for each power system limitation (typically: thermal, safety/reliability, power quality/voltage, and protection) to approximate the DER capacity limit at nodes across the distribution circuit.

The iterative method directly models DERs on the distribution grid to identify hosting capacity limitations. A power flow simulation is run iteratively at each node on the distribution system until a violation of one of the four power system limitations is identified. The iterative method is also sometimes referred to as the detailed method.

The stochastic method starts with a model of the existing distribution system, then new solar PV (or other DERs) of varying sizes are added to a feeder at randomly selected locations and the feeder is evaluated for any adverse effects that arise from this random allocation. This essentially results in a hosting capacity range.

Different methodologies can result in different hosting capacity values due to different technical assumptions built into the models, and the methodological choices in an HCA can significantly impact whether the results are sufficiently reliable and informative for grid-related planning and decision-making. Section IV of the full guide outlines several key considerations when evaluating and selecting HCA methodologies.

Use cases can be selected to reflect the unique characteristics and identified goals of states and utilities. These use cases should inform and guide the development of an HCA methodology and its implementation.

Regulatory Process Underpinning Hosting Capacity Analyses

The *process* underpinning HCA efforts is key to ensuring that the HCA tool is deployed to support relevant state policy goals and sufficiently reflects the input from stakeholders, ultimately enhancing the benefits for all ratepayers. Still an emerging grid modernization tool, the benefits and drawbacks of different HCA methodologies are being revealed, and likely will become even more apparent with time. However, rather than wait for the perfect HCA methodology to emerge, regulators can take initial steps to gain familiarity and understanding of the different HCA methodologies, their function, their capabilities, and their limitations. Given the substantial investment in time, energy and resources that HCA efforts require, there is value in taking the time early in the process to ensure that the tool being developed is capable of meeting identified objectives. Questions or concerns about what an HCA can do should be addressed before widespread implementation, lest substantial resources be invested in something that proves invaluable or ambiguously useful. This paper identifies the key process steps and considerations therein, summarized as follows:

Establish a stakeholder process to work with utilities and other interested stakeholders to select, refine and implement the HCA. Ideally, this process should involve one or more working groups consisting of utility and non-utility participants with oversight from regulators to guide the HCA development. Regulators should also retain a process to improve on the selected HCA methodology over time and establish clear timelines for utilities to meet near and long-term HCA goals. Figure ES-2 outlines best practices for stakeholder engagement, drawing from lessons learned in states such as California, Minnesota and New York.

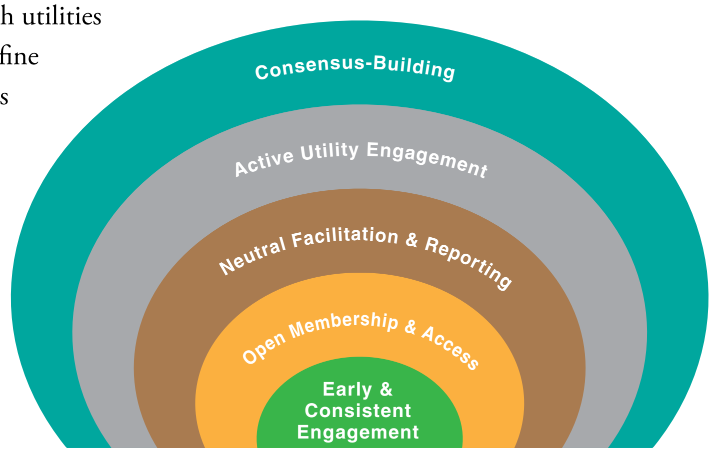


Figure ES-2. Regulatory Stakeholder Engagement Strategies

Select and define the use cases for the HCA with input from diverse stakeholders, ensuring they are clearly designed to address and achieve identified goals, including state energy policy goals. These use cases should inform and guide the development of an HCA methodology and its implementation. As regulators and utilities consider undertaking an HCA, it is critical that all stakeholders carefully consider and select desired use cases for HCA together at the beginning of the process. Defining use cases ensures that the cart is not put before the horse and will also prevent potentially costly and inefficient undertakings that do not produce useable results.

Identify criteria to guide implementation of the HCA at the outset. Working through the established stakeholder process to identify and answer key questions regarding the scope, duration and other key elements of the HCA can help ensure a more efficient process throughout (and greater buy-in from all involved). The *frequency of updating* the HCA results, the *extent of the grid covered by HCA*, and *criteria for ensuring transparency* in the selected HCA methodology and its results are all important to discuss and define. In addition, regulators may consider whether to create a phased roadmap for implementation of HCA, depending on the level of sophistication of the utilities and the timeline for achieving state energy goals. However, care should be taken not to create an endless implementation timeline that quickly becomes obsolete or fails to miss near term opportunities for deployment and use.

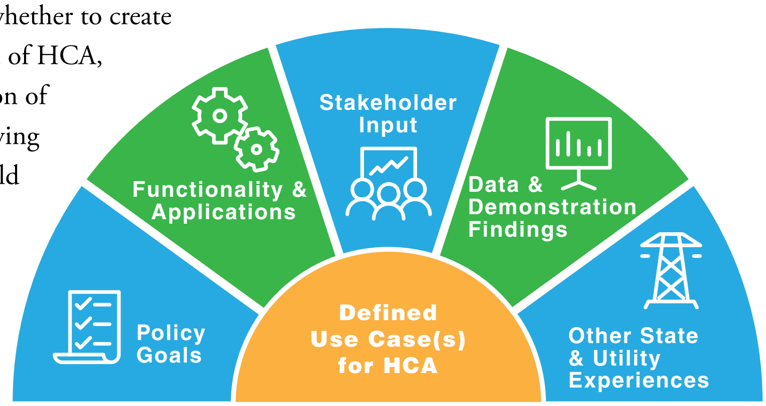


Figure ES-3. Key Elements to Defining Use Case(s) for HCA

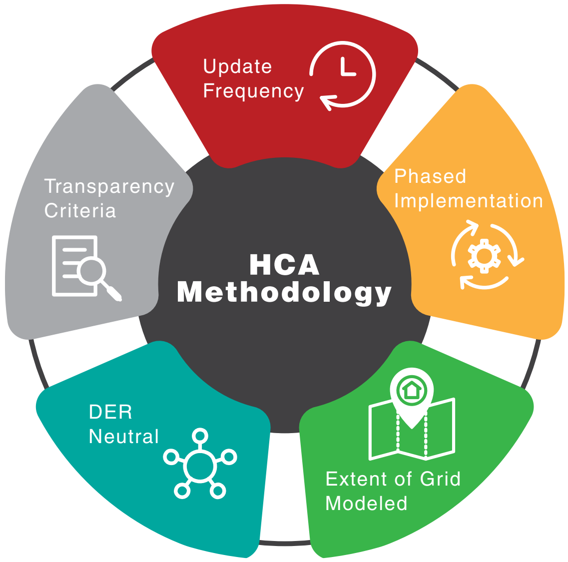


Figure ES-4. Criteria to Guide Implementation of HCA

Develop an HCA methodology (or methodologies) most appropriate to the use cases. Regulators will need to provide sufficient guidance for utilities to clarify what HCA should be capable of doing and how it can be used to support identified goals, such that the final tool is designed appropriately to meet such goals. This can be accomplished by providing clear and specific guidance and ensuring that the methodologies and assumptions are transparent and informative to all involved stakeholders and end-users. Regulators should ensure that the HCA methodology is scalable so that, even under an incremental approach, the full grid and range of DERs can eventually be analyzed. Different methodologies can result in different hosting capacity values due to different technical assumptions built into the models. Given the variety of factors that affect the grid's ability to host a wide range of DERs, it is necessary to select a well-considered methodology for determining hosting capacity based upon its intended use.

Validate the results of the HCA over time. As with any model or analysis, real-world validation can help improve accuracy and functionality over time. Transparency in the methodology and assumptions and ready access to HCA results will ensure that they can be easily validated and any problems with the methodology identified and resolved. Ideally, sufficient information about the methodology should exist so that a third party could perform an independent analysis to validate the results reached by utilities. Regulators will need to consider the most useful manner for utilities to publish and display hosting capacity data, and set milestones over time to evaluate the performance of the HCA, relative to identified goals.

Regulators will need to provide sufficient guidance for utilities to clarify what HCA should be capable of doing and how it can be used to support identified goals, such that the final tool is designed appropriately to meet such goals.

As regulators oversee the implementation of HCAs, there are other key considerations to keep in mind, noted throughout the guide. For example, requiring consistency in approaches and methodologies among utilities (where there are multiple utility services territories within a state) will help simplify the implementation and oversight process, while also ensuring a more consistent and efficient utilization of this tool among DER project developers and customers. Data sharing is another key factor shaping the evolution of the electricity grid, and the data collected and generated as part of an HCA will help utilities, regulators, and DER customers better capture the diverse value streams of DERs. Concerns surrounding data sharing can and should be managed proactively and should not be a reason to not pursue HCAs or related efforts.

In addition, given swift changes to technologies, performance and markets, HCAs should be agnostic to the type of DER analyzed to ensure that it remains useful over time. Technology agnosticism can also help utilities identify opportunities to expand hosting capacity with other DERs and deploy non-wires alternatives as part of utility grid upgrades and investment plans.

As utilities plan for and pursue (or solicit from third parties) grid infrastructure improvements over time, HCAs can help ensure that DERs are optimized, not discouraged, on the system as an integrated and functional feature of affordable, quality and reliable electricityservice provided to all ratepayers.

Perhaps most importantly, HCAs should not be developed or implemented in a vacuum, and should be considered in the context of other policy choices and how they may impact how DERs are deployed. As consumers and the market responds to new programs, policies and price signals, so too should the HCAs reflect the anticipated and planned changes to DER adoption. More robust DER forecasting methodologies will need to be developed in order to provide greater accuracy of the HCA.

Ultimately, as utilities plan for and pursue (or solicit from third parties) grid infrastructure improvements over time, HCAs can help ensure that DERs are optimized, not discouraged, on the system as an integrated and functional feature of affordable, quality and reliable electricity service provided to all ratepayers.

With this guide in hand, regulators can provide the leadership and direction needed to ensure the process, function, and implementation of HCA supports and enables the critical grid transformations underway across the country.

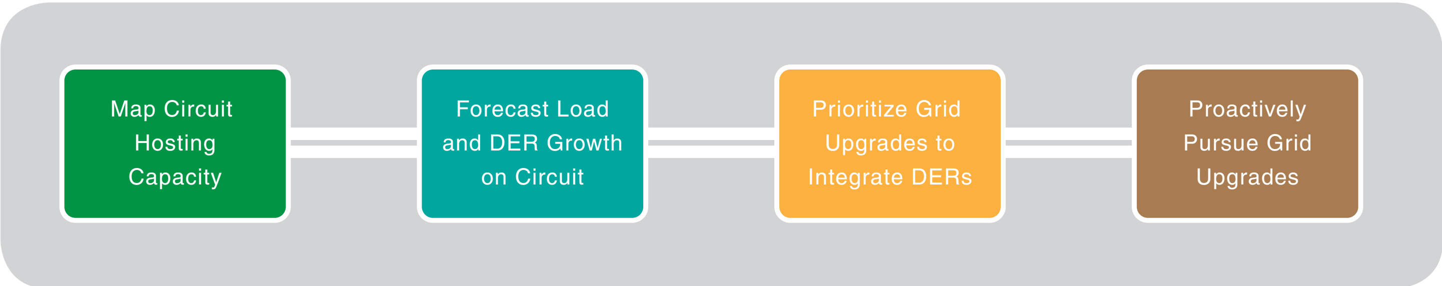
I. Introduction

Hosting capacity analysis, or HCA, has emerged as a key tool for capturing and optimizing the benefits of distributed energy resources (DER)[1] on the grid, while also proactively managing increasing penetrations of DERs and ensuring the reliability of the grid. HCA is used to determine the amount of DERs that the distribution system can accommodate at a given time and a given location. HCA allows utilities, regulators, and DER customers to make more efficient and cost-effective choices about whether to pursue interconnection of a DER technology at a specific grid location by providing data about the amount of new DERs that can be accommodated at a particular node[2] on the grid. Mapping the hosting capacity of the entire distribution grid provides even more powerful benefits: customers can identify optimal locations to install and interconnect DERs; regulators and utilities can develop price signals to direct DERs to locations on the grid where they can provide the greatest benefit; and utilities can better plan for grid infrastructure improvements that expand hosting capacity at locations with high demand for DERs. Ultimately these actions will optimize the deployment of DERs on the system to preserve and improve the quality of service they provide to all ratepayers.

IREC and Sandia National Laboratories set forth the concept of Integrated Distribution Planning (IDP) as an approach to proactive planning for DER growth at high penetrations. IDP consists of four principal components: (1) mapping a circuit's hosting capacity; (2) forecasting the expected growth of DERs on that circuit; (3) prioritizing grid

Hosting capacity analysis, or HCA, has emerged as a key tool for capturing and optimizing the benefits of distributed energy resources (DERs).

Figure 1. Principal Components of Integrated Distribution Planning



upgrades to integrate DERs; and (4) proactively pursuing grid upgrades (including traditional capital upgrades as well as DERs themselves) to meet anticipated grid needs. By combining HCA with DER forecasting, a utility can better plan for grid upgrades to facilitate and enable the integration of forecasted DER growth in specific areas. Regulators and utilities can also steer DERs to the grid locations where they can provide the greatest system benefits at the least cost. States and utilities around the country are beginning to adopt IDP approaches.[4] The widespread adoption of IDP holds tremendous promise for enabling the modernization of the distribution grid, but the hosting capacity piece of the IDP puzzle remains at a nascent stage.

The intent of this paper is to support regulators as they guide and inform the implementation of a hosting capacity analysis, as part of a broader grid modernization or distribution planning effort and in support of their state's near- and long-term energy policy goals.

The purpose of this paper is to assist state regulators in guiding and overseeing utilities as they prepare hosting capacity analyses on their distribution circuits. Based on lessons from the handful of states and utilities that have begun to prepare hosting capacity analyses, the paper focuses on the process that will help regulators realize the full promise of HCA in their respective states. The experiences and key takeaways from the states undertaking these analyses are fully outlined in the case studies which can be found in Appendix A. Key process steps discussed in this paper include:

- Definition and selection of use cases[5] for HCA tailored to the needs and goals of their states;
- Selection of the hosting capacity methodology best suited to realizing identified use cases; and
- Establishing rules and criteria to implement and improve on that methodology.

A number of resources exist to guide regulators and utilities in exploring the technical aspects of hosting capacity methodologies.[6] Exploring the technical nuances of those methodologies is beyond the scope of this paper, which will instead highlight some of the tradeoffs between methodologies that may make them more or less suited to the various use cases that regulators may select. In sum, the intent of this paper is to support regulators as they guide and inform the implementation of a hosting capacity analysis, as part of a broader grid modernization or distribution planning effort and in support of their state's near- and long-term energy policy goals.

II. Hosting Capacity Fundamentals

A. HOSTING CAPACITY DEFINITION

As used in this paper, the term "hosting capacity" refers to the amount of DERs that can be accommodated on the distribution system under existing grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria, and without requiring significant infrastructure upgrades.[7] HCA evaluates a variety of circuit operational criteria—typically thermal, power quality/voltage, protection, and safety/reliability[8]—under the presence of a given level of DER penetration and identifies the limiting factor or factors for DER interconnections.[9] The hosting capacity is the greatest amount of a DER with a specific operational profile, such as that of solar photovoltaics (PV) or an energy storage system, that can be accommodated before a violation of one or more of the technical criteria occurs on a line section or feeder.[10] To provide the accuracy needed to guide distribution-level decision-making and/or inform the interconnection process, the HCA needs to be performed at a granular level (typically at every selected node on assessed feeders) across the entire distribution circuit.

HCA reveals snapshots of the amount of different types of DERs that can be hosted at a particular point in time across the grid. These snapshots are not fixed but change constantly as grid conditions change: that is, as new DERs are interconnected, as new controls are added to the circuit, and/or as load curves shift.

The main factors that drive the amount of DER that can be hosted on the grid, without requiring upgrades or modifications to the distribution system are:

(1) precise DER location,

(2) nature of the load curve on the feeder,

(3) the feeder's design and physical and operational characteristics, and

(4) DER technology.[11]

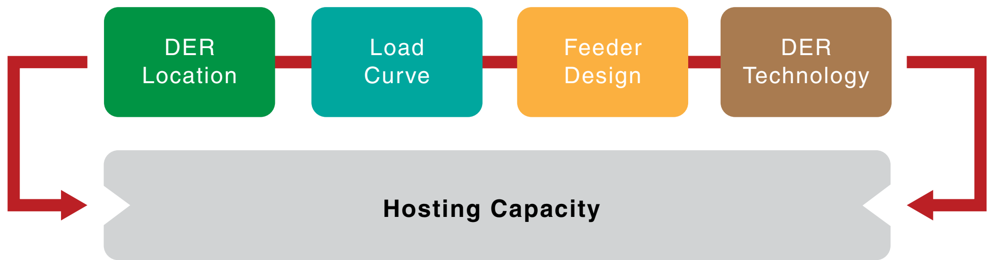


Figure 2. Factors Impacting Hosting Capacity

Distribution Grid Terms

Distribution Circuit—The conductors and devices downstream of the substation feeder breaker and including all laterals, primary and secondary portions.

Feeder—A single distribution line which connects the substation at primary voltage to laterals or secondary circuits.

Line section—A portion of a distribution circuit between two automatic sectionalizing devices or an automatic sectionalizing device and the end of the distribution line. Automatic sectionalizing devices would typically refer to the feeder breaker or line reclosers, but could include other devices.

Node—A node is a point on a feeder between two line sections. Circuit characteristics may be analyzed at each selected node along the circuit.

The hosting capacity of any given feeder is a range of values, which depend on the specific location and type of resource in question.[12] For instance, a feeder may be able to accommodate 2 MW of solar PV at a node close to the substation but only 0.5 MW (500 kW) at a node further from the substation, or a feeder may be able to accommodate more solar PV with advanced inverters than solar PV without advanced inverters.[13] The hosting capacity also varies significantly between DER technologies, feeder characteristics, such as a voltage class, regulating devices, and load profile.

A well-considered methodology for determining hosting capacity is necessary given the variety of factors that can affect the grid's ability to host a wide range of DERs. IREC has identified three principal categories of methodologies that are currently being tested and employed by utilities to analyze hosting capacity, generally known as the stochastic, iterative, and streamlined methods. These methodologies, including the tradeoffs between them, are described in detail below. There is overlap between the methods, as well as iterations of each type. For example, the Electric Power Research Institute (EPRI) recently developed the DRIVE tool, which EPRI characterizes as a version of the streamlined method.[14] Information has not yet been published detailing the differences between EPRI's version of the streamlined methodology and the streamlined methodology tested in California and discussed below.

Importantly, the methodologies can result in different hosting capacity values due to different technical assumptions built into the models. Certain assumptions, such as how many load hours or nodes are evaluated, may also result in more or less precise hosting capacity assessments. The methodological choices in an HCA can significantly impact whether the results are sufficiently reliable and informative for grid-related planning and decision-making. To achieve a rigorous HCA, regulators and utilities should carefully consider and articulate their goals and use cases at the outset of an HCA effort, and then select and tailor the methodology best suited to achieve those objectives.

B. HOSTING CAPACITY USE CASES

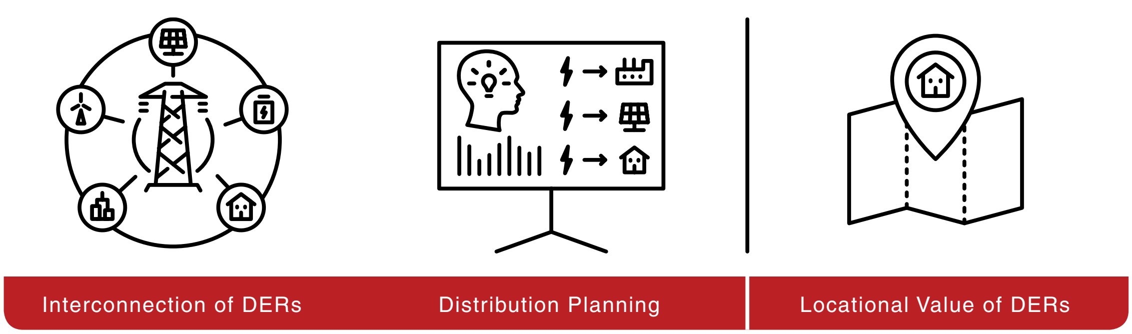
There are two principal applications, or use cases, for an HCA: 1) assist with and support the streamlined interconnection of DERs on the distribution grid; and 2) enable more robust and granular distribution system planning. The third complementary function of an HCA could be to inform pricing mechanisms for DERs based on separate analyses to assess the locational benefits of DERs.

Use cases can be selected to reflect the unique characteristics and identified goals of the state and utility. These use cases should inform and guide the development of an HCA methodology and its implementation. A process should also be in place to refine the selected use cases as new regulatory, social, and technological conditions emerge. The two major HCA use cases—interconnection and planning—as well as the complementary function of optimizing the locational benefits of DERs are discussed in detail below.

As regulators and utilities consider undertaking an HCA, it is critical that all stakeholders carefully consider and select desired use cases at the beginning of the process. Selecting an HCA methodology before defining the use cases puts the cart before the horse; a methodology may need to be dramatically altered or discarded entirely if it turns out to be ill-suited to meeting the state's or utility's goals. As described in the case studies in Appendix A, the failure to consider the use cases prior to selecting the methodologies has resulted in a potential need to revise the methodologies in California. In addition, stakeholders have voiced concerns about whether the methodologies used in Minnesota and New York will actually be able to achieve those states' goals.

As regulators and utilities consider undertaking an HCA, it is critical that all stakeholders carefully consider and select desired use cases at the beginning of the process. Selecting an HCA methodology before defining the use cases puts the cart before the horse; a methodology may need to be dramatically altered or discarded entirely if it turns out to be ill-suited to meeting the state's or utility's goals.

Figure 3. Hosting Capacity Use Cases



Regulators, with input from involved stakeholders, should not only identify desired HCA use cases up front, but they should also do so with specificity. Regulators will need to provide sufficient guidance for utilities to clarify what HCA should be capable of doing and how it can be used to support identified goals so that the final tool is designed appropriately to meet those goals. For example, if more streamlined interconnection processes is the goal, then there should be some early discussions, before the tool is built, around what level of precision in the HCA would be needed to accomplish this objective.

Regulators, with input from involved stakeholders, should not only identify desired HCA use cases up front, but they should also do so with specificity. Regulators will need to provide sufficient guidance for utilities to clarify what HCA should be capable of doing and how it can be used to support identified goals so that the final tool is designed appropriately to meet those goals.

In addition to identifying use cases, regulators may consider identifying specific elements to guide utilities in developing the HCA methodology. Such elements can include:

(1) specification of the desired level of granularity (i.e., performing HCA down to the line section and node level);

(2) specification of the desired level of scalability (i.e., whether HCA should be performed across the entire distribution system at the outset or only on those feeders with the greatest projected DER demand, and whether it should be performed on single-phase feeders in addition to three-phase feeders);

(3) guidance for repeatability as new DERs are interconnected and feeder characteristics change;

(4) transparency in the methods and results;

(5) validation of techniques to ensure confidence in the results obtained through the HCA;

(6) readily accessible data for easy use by consumers, developers, and planners;[15]

(7) frequency of publication (i.e., annual, quarterly, real-time, etc.); and

(8) types of DERs to be modeled (i.e., distributed generation, energy storage, electric vehicles, or all DERs).

At the same time, regulators may want to avoid being overly prescriptive in their goals so that utilities have the space to develop a workable tool for their service areas in a timely manner. Conducting an open dialogue about the pros and cons of approaches that have been piloted by states and utilities (including those discussed in the case studies in Appendix A) can help regulators determine how best to strike a balance between prescribing detailed goals and allowing some flexibility for utilities.

III. Selecting the Hosting Capacity Use Cases

The use cases that regulators, stakeholders, and utilities select for HCA will inform the choice of HCA methodology and the guidelines for deploying it, such as the frequency of updating and the portions of the grid to be covered by the initial HCA rollout. The two primary use cases for HCA— interconnection and planning—are described herein. In addition, the following section includes a discussion of how the HCA can be used in a complementary fashion along with efforts to identify locational benefits of DERs to fully optimize DER siting.

A. INTERCONNECTION USE CASE

In many states, interconnection standards and utility interconnection processes are not keeping pace with DER growth and are replete with inefficiencies and time- and resource-intensive protocols that cause backlogs and interconnection gridlock.[16] For example, a 2015 study by NREL found that utilities in five states failed to meet review time requirements for up to 58% of residential and small commercial solar interconnection applications.[17] In states, such as in North Carolina, where there have been significant amounts of larger-scale distributed generation deployed (e.g., projects 1 MW or greater), the utilities have fallen drastically behind on their ability to keep up with the interconnection study process. As an example of this interconnection gridlock in North Carolina, Duke Energy regularly takes more than a year to complete the study process for the interconnection of a 2 to 5 MW solar PV generator on its distribution system.[18]

While a number of factors can contribute to interconnection gridlock, a prominent one is that customers wanting to adopt DERs have traditionally had limited access to information about the conditions on the grid to help them select optimal and appropriate sites and design projects that are responsive to (and not in violation of) the available hosting capacity at their chosen site. Another barrier to streamlined interconnection processes is the time- and bandwidth-limited utility staff who are tasked with processing increasing volumes of DER interconnection requests. Even requests that are not likely to move forward—because they require costly grid upgrades to accommodate them on the system—still require the time and attention of utility staff to review and study the interconnection applications. Providing customers with more information upfront, such as through an HCA and accompanying distribution system map, can help reduce the number of ill-suited projects proposed and result in better designed projects that are within the hosting capacity at that particular site and thus could require fewer utility resources to be spent individually studying their impacts.[19]

1. Streamlining the Interconnection Processes for DERs

HCA can help address the challenges of interconnection gridlock in two important ways. First, HCA can provide reliable data about the hosting capacity of nodes across the circuit for use in streamlining and expediting the review of interconnection applications. When a customer seeks to interconnect at a given node, the utility can check to see if its proposed DER project falls within the hosting capacity value for that location. If it does, the project can be approved to interconnect with little to no additional review or study with assurance that it will not compromise system safety or reliability. Second, if the project falls outside the identified hosting capacity, it can be directed to the study process or the customer can be provided information that allows her to redesign the project to fit within the hosting capacity limits (and/or address known constraints through system or operational redesign). Perhaps most importantly, HCAs based on the actual engineering specifications of the circuit are able to yield *more precise indicators of the amount of DER that can be accommodated than the simplified interconnection screens in place in many states today*,[20] such as the 15 percent of peak load screen commonly used to determine whether a project connecting to the distribution grid will raise islanding concerns or cause backfeed beyond the substation.[21] By providing a more accurate and efficient method of reviewing a project, HCA allows more DERs to connect to the grid more promptly, *without compromising grid safety and reliability*.[22]

Ultimately, with frequent updating of HCA, utilities can move toward automated interconnection processes. Interconnection customers can also use the detailed HCA data to identify potential project alternatives that would help them avoid hosting capacity limits, such as use of on-site storage to shift peak demand or interconnection agreements that allow curtailment during limited peak hours of the year.[23]

2. Maps to Identify Grid Locations for DERs

Mapping the hosting capacity of entire circuits and making these results publicly available can help guide DER customers to locations where they can provide more value to the grid and minimize project costs. User-friendly maps displaying HCA results and downloadable data files will also help customers understand what project sizes and technologies can be most easily accommodated in a particular location, which can help them better predict the cost and timeline of the interconnection process.[24] Giving customers the ability to self-select optimal interconnection sites will in itself speed up the interconnection process by channeling applications to the grid locations where they are most likely to be quickly approved. Early grid mapping efforts and adoption of pre-application reports,[25] in states such as California and Hawaii, have been widely accepted as a useful tool by both DER customers and utilities. They appear to be positively redirecting projects and reducing the number of speculative or non-viable projects that ultimately seek to interconnect.[26]

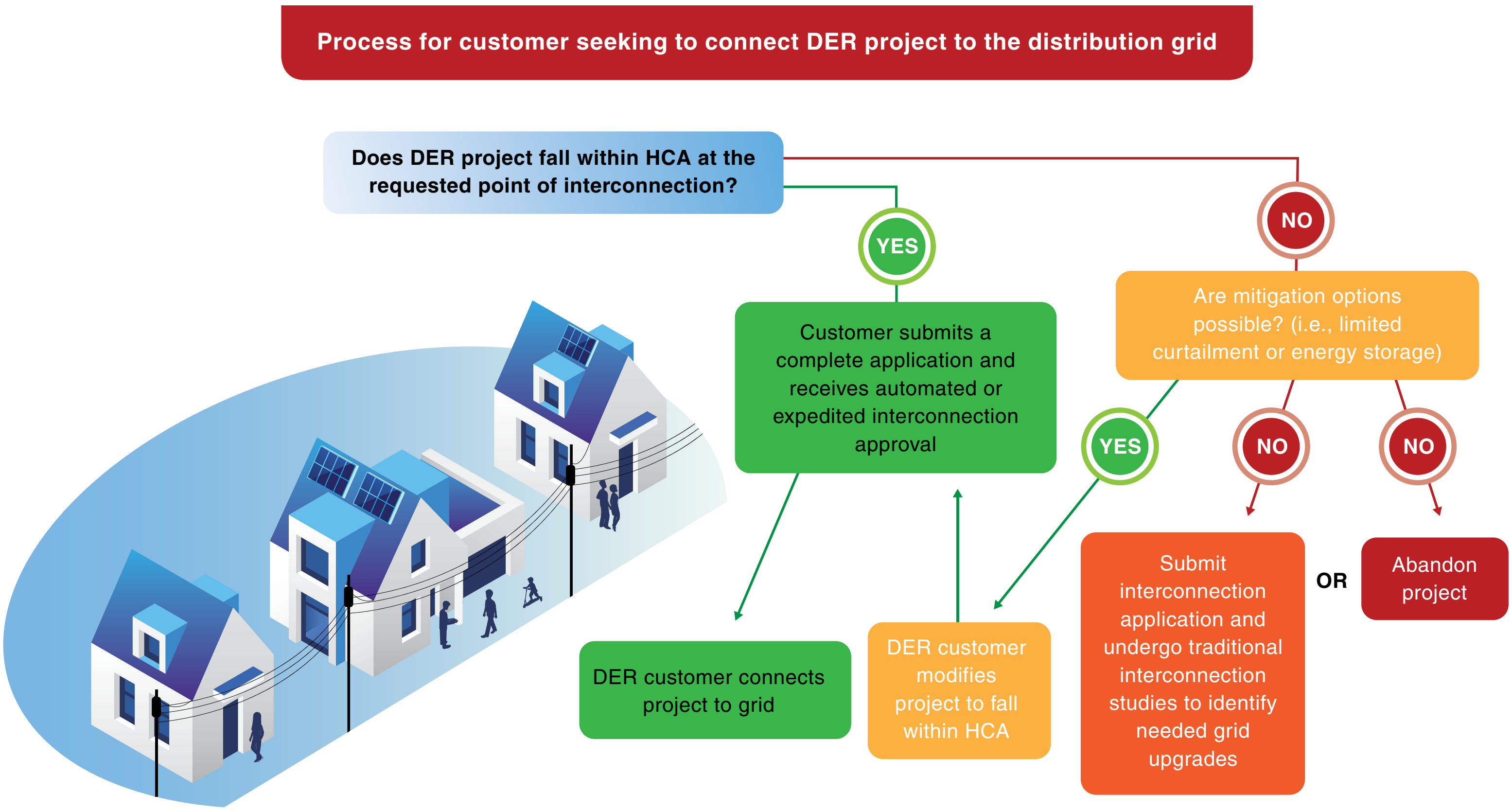


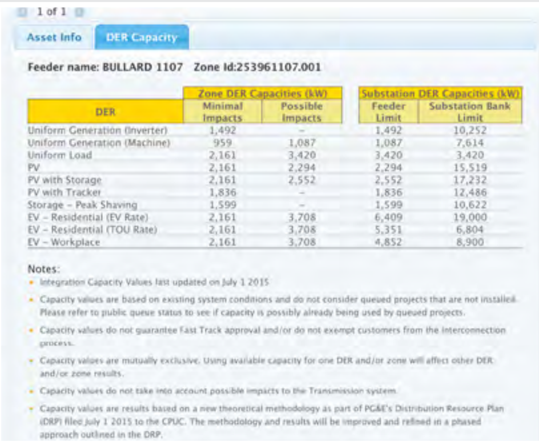
Figure 4. Illustrative Interconnection Use Case for HCA

As discussed below, an HCA map can also be combined with efforts to identify precise locational values to further optimize DER siting.

When interconnection is selected as a use case for HCA, regulators should ensure that the methodology chosen and implemented by utilities yields sufficiently reliable, robust, and granular results and is deployed with sufficient frequency to achieve identified goals and use case functionality. For example, the accuracy of the hosting capacity results is critical to ensuring safe and reliable interconnection while also increasing efficiency and avoiding an overbuilt distribution system. Frequency and accuracy are closely connected and impact the usefulness of the tool for more streamlined interconnection processes. Maps and data files should be updated with new HCA results each time they are generated to ensure that customers have the most current information to make their siting and application decisions.

3. State Experiences with the Interconnection Use Case for HCA

Early experiences in three states demonstrate the value of setting forth interconnection as a use case at the *beginning* of the HCA process (see the case studies in Appendix A for more details regarding individual state experiences).



1 of 1

Asset Info | DER Capacity

Feeder name: BULLARD 1107 Zone Id:253961107.001

DER	Zone DER Capacities (kW)		Substation DER Capacities (kW)	
	Minimal Impacts	Possible Impacts	Feeder Limit	Substation Bank Limit
Uniform Generation (Inverter)	1,492	–	1,492	10,252
Uniform Generation (Machine)	959	1,087	1,087	7,614
Uniform Load	2,161	3,420	3,420	3,420
PV	2,161	2,294	2,294	15,519
PV with Storage	2,161	2,552	2,552	17,232
PV with Tracker	1,836	–	1,836	12,486
Storage – Peak Shaving	1,599	–	1,599	10,622
EV – Residential (EV Rate)	2,161	3,708	6,409	19,000
EV – Residential (TOU Rate)	2,161	3,708	5,351	6,804
EV – Workplace	2,161	3,708	4,852	8,900

Notes:

- Integration Capacity Values last updated on July 1 2015
- Capacity values are based on existing system conditions and do not consider queued projects that are not installed. Please refer to public queue status to see if capacity is possibly already being used by queued projects.
- Capacity values do not guarantee Fast Track approval and/or do not exempt customers from the interconnection process.
- Capacity values are mutually exclusive. Using available capacity for one DER and/or zone will affect other DER and/or zone results.
- Capacity values do not take into account possible impacts to the Transmission system.
- Capacity values are results based on a new theoretical methodology as part of PG&E's Distribution Resource Plan (DRP) filed July 1 2015 to the CPUC. The methodology and results will be improved and refined in a phased approach outlined in the DRP.

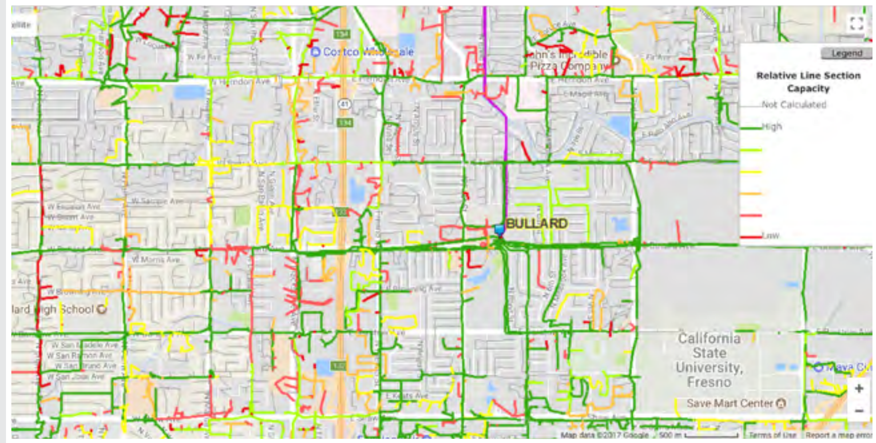


Figure 5. Sample Hosting Capacity Map & Feeder Data

Source: *PG&E, Demonstration A, Integration Capacity Map, available at: https://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/PVRAMMap/index.shtml*

In California, the Public Utilities Commission (CPUC) initially ordered the state's major investor owned utilities to prepare an initial integration capacity analysis (synonymous with a hosting capacity analysis) as one part of a Distributed Resources Plan (DRP).[27] The CPUC's guidance ruling specified that one of the goals of the analysis was to "improve the efficiency of the grid interconnection process" and included some specific details in terms of number of circuits, granularity, and modeling methods.[28] After the utilities completed their initial limited deployments, the CPUC took comments and then authorized a more comprehensive demonstration project that would ultimately test out two different methodologies, in consultation with a working group of diverse stakeholders.[29] The lesson learned from this process was that to properly evaluate the methodologies tested, use cases needed to be developed that identified the state's concrete interconnection goals. After identifying those goals more precisely and developing the use cases, the majority of the working group concluded that the streamlined methodology, as tested, was inadequate to meet the goals and that the iterative methodology was better suited to achieve the accuracy and precision required for the interconnection use case.[30] The CPUC ultimately adopted the recommendations of the working group and ordered the utilities to deploy the iterative methodology system-wide for the interconnection use case.[31] The utilities in Hawaii are using a method similar to the iterative method selected in California for use in the interconnection process,[32] and they have identified interconnection as a clear use case for hosting capacity in the state, although the Commission has not yet approved its incorporation into the interconnection procedures.[33]

In New York, by contrast, as part of the Distribution System Implementation Plans (DSIP) docket[34] within the much-larger New York Reforming the Energy Vision (NY REV), the Joint Utilities[35] established the goal of providing HCA maps for customers to use in identifying optimal interconnection grid locations for large-scale solar PV. However, the utilities declined to clearly identify and define interconnection as a use case for the HCA, instead noting only that stakeholders were interested in "exploring the possible implementation of interconnection use cases for hosting capacity."[36] Despite comments from stakeholders urging the New York Public Service Commission (NY PSC) to clearly define use cases and to require examination and transparency regarding whether the selected methodology provides results accurate and reliable enough to meet those use cases, the NY PSC declined to further investigate.[37] The Joint Utilities are thus moving ahead with EPRI's DRIVE Tool (a version of the streamlined method) for their HCAs, but considerable uncertainty remains about whether HCAs developed using this method will help process interconnection requests and shorten timelines, or even whether the current results can accurately guide customers to appropriate interconnection locations. The Joint Utilities' HCAs are also unlikely to be useful in informing scenarios for other DERs, including non-solar distributed generation, smaller-scale solar, distributed energy storage, and/or electric vehicles.

Lastly, the Minnesota Public Utilities Commission (MN PUC) has identified some value to using HCA to inform interconnection as a long-term goal of Xcel Energy's (the state's major investor owned utility) HCA effort, but it has not gone so far as to precisely define the use case.[38] The MN PUC required Xcel Energy to "conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources,"[39] but the initial distribution-system study released by Xcel Energy announced that its HCA results were "not intended to be used for approving interconnection requests," and did not to set forth a process or timeline for producing HCA results that would help to streamline interconnection approvals.[40] After considering stakeholder written and oral comments, the MN PUC required Xcel to file hosting capacity reports with sufficient detail to provide customers "with a starting point for interconnection applications."[41] The MN PUC also directed Xcel to provide information requested by staff and parties on the accuracy of its HCA results, including by conducting a comparison of results in its 2016 report with actual hosting capacity determined through interconnection studies.[42] This information was provided in a subsequent filing[43] and the MN PUC and parties are evaluating the results of the accuracy assessment and what it means for next steps.

As these state experiences illustrate, commencing a hosting capacity process without clear uses and goals creates a real risk of duplicative expenditures by utilities, which are ultimately borne by ratepayers. For instance, if a state selects an HCA methodology not suited to interconnection processing and invests in optimizing that method, utilities will not only expend substantial resources processing individual interconnection applications in the interim, but they may ultimately expend far more resources switching in the future to an HCA method capable of streamlining the interconnection process if that is ultimately desired. To avoid these pitfalls, IREC recommends that regulators learn from the comparative analysis done in California and involve utilities and stakeholders in early discussions about whether interconnection is an appropriate use case for the HCA. If it is adopted, regulators should require utilities to develop and implement an HCA methodology appropriate to that use case.

As these state experiences illustrate, commencing a hosting capacity process without clear uses and goals creates a real risk of duplicative expenditures by utilities, which are ultimately borne by ratepayers.

B. PLANNING USE CASE

Planning is the other primary use case for HCA. Although distribution planning is often framed as an important goal for HCA, no regulator or utility has specified exactly how HCA will be used in the distribution planning process. Failing to specifically define the planning use case can impede regulators' ability to ensure that the HCA methodology developed and deployed will ultimately serve the planning goals. While fewer details are available about the planning use case, based on a lack of concrete examples to draw from, there are emerging grid planning reforms that states are adopting as part of broader grid modernization efforts, which provide useful guidance to regulators considering how to best approach the planning use case for HCAs.

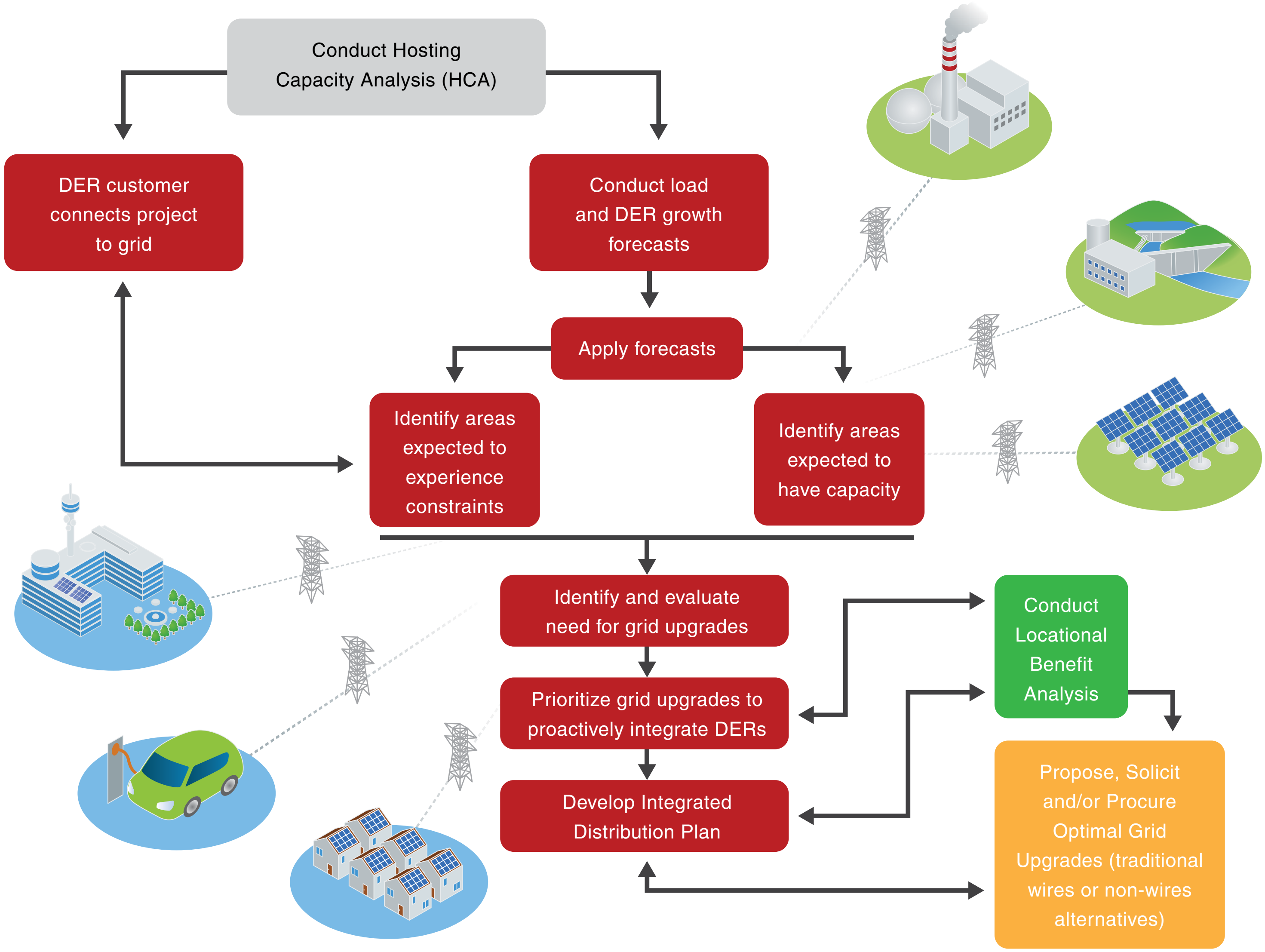
1. Shifting to Proactive, Integrated Distribution Planning

Traditionally, distribution system planning has remained within the exclusive purview of the utilities, and there has been minimal transparency or public involvement in the planning process.[44] In addition, utility-owned assets are normally the preferred solutions to meet identified distribution needs.[45] However, this traditional model for distribution system planning is continuing to evolve with, among other changes, increasing penetration of distributed generation, increased deployment of demand-response technologies, growing customer investments in energy storage and energy management technologies, and policy directives to utilities to build cleaner, more reliable, and more efficient electricity systems. In response to these new conditions, planning the grid for the future warrants new approaches that take into account the growth, benefits and impacts of DERs on the grid, including revised load forecasting and the ability of DERs to offer "non-wires" solutions to distribution grid needs. Both vertically integrated and deregulated states are beginning to recognize that the role of the distribution system is fundamentally changing and the planning process must evolve accordingly.[46] In response, regulators are requiring increasing transparency in the distribution planning process, including by requiring utilities to publicly file distribution resource plans and to increase access to grid data.[47]

The Integrated Distribution Planning process consists of four basic components: (1) mapping the hosting capacity of the system; (2) forecasting DER growth and load growth, (2) identifying and prioritizing grid upgrade needs by comparing growth to available circuit hosting capacities, (3) proactively pursuing grid solutions, including non-wires alternatives, to meet identified needs and integrate and optimize DERs on the grid.[48]

As depicted in Figure 6, an HCA is a central component of more proactive, integrated distribution system planning. Among other functions, an HCA can facilitate utility efforts

Figure 6. Illustrative Planning Use Case for HCA



to integrate DERs under high penetration scenarios, to meet renewable or distributed energy mandates, and to procure and/or deploy DERs as cost-effective, non-wires alternatives to traditional grid investments.[49]

As an alternative to the current reactive process to making distribution system upgrades (wherein the customer with the DER project that triggers the need for a grid upgrade is expected to bear the entire upgrade cost), an HCA can help utilities (and regulators) more proactively identify in advance strategic locations where cost-effective infrastructure investments can increase hosting capacity,[50] thereby benefiting a number of DER customers and other ratepayers. This proactive planning approach permits more efficient and economic allocation of system upgrades, while also optimizing benefits across sources of generation and load and across any number of distribution feeders. It can also speed up the process of interconnecting DERs since steps to expand hosting capacity will have been taken, where appropriate, prior to applications being submitted. By planning for and performing proactive upgrades, utilities can also consider ways to spread upgrade costs more evenly between parties that benefit from them (thus avoiding the scenario where a single customer gets left holding the bag for costly grid upgrades, which ultimately improve hosting capacity for other customers that come after them), including both customers with new generation and load on the distribution system. Lastly, they can procure third-party solutions, including DERs, to meet projected grid needs in lieu of, or in addition to, traditionally procured infrastructure investments.[51]

Clearly defining IDP as a goal of the HCA use case can help ensure that the analysis is fully supportive of this more proactive approach to grid planning. In addition, to ensure that planning goals are realized, it may be necessary to make further improvements to the interconnection processes to facilitate DER integration and capture "the value of DER linked to planning results and opportunities to realize net benefits for all customers through the use of DER provided services."[52]

By articulating with precision the goals of the HCA planning use case, regulators can ensure that an effective HCA tool is developed. For instance, where IDP is part of the planning use case, the HCA may need to be run on the entire distribution system under different scenarios about assumed DER growth overlying varying time horizons.[53] The HCA results would enable the utility to determine when and where the distribution grid is projected to reach its hosting capacity such that solutions can be deployed or procured *before* that location is closed to new DER projects. Regulators should consider how frequently the HCA needs to be run and the level of precision in the HCA results necessary to meet the planning use case goals.

2. Using HCA to Model and Plan for Changes in Customer Behavior

An HCA, as part of the planning use case, can also be used as a tool to help understand how other policy choices may impact how DERs are deployed and how the hosting capacity of the distribution system would change as a result. For example, if a utility is exploring the impact of time-of-use rates for electric vehicle owners, the HCA can be

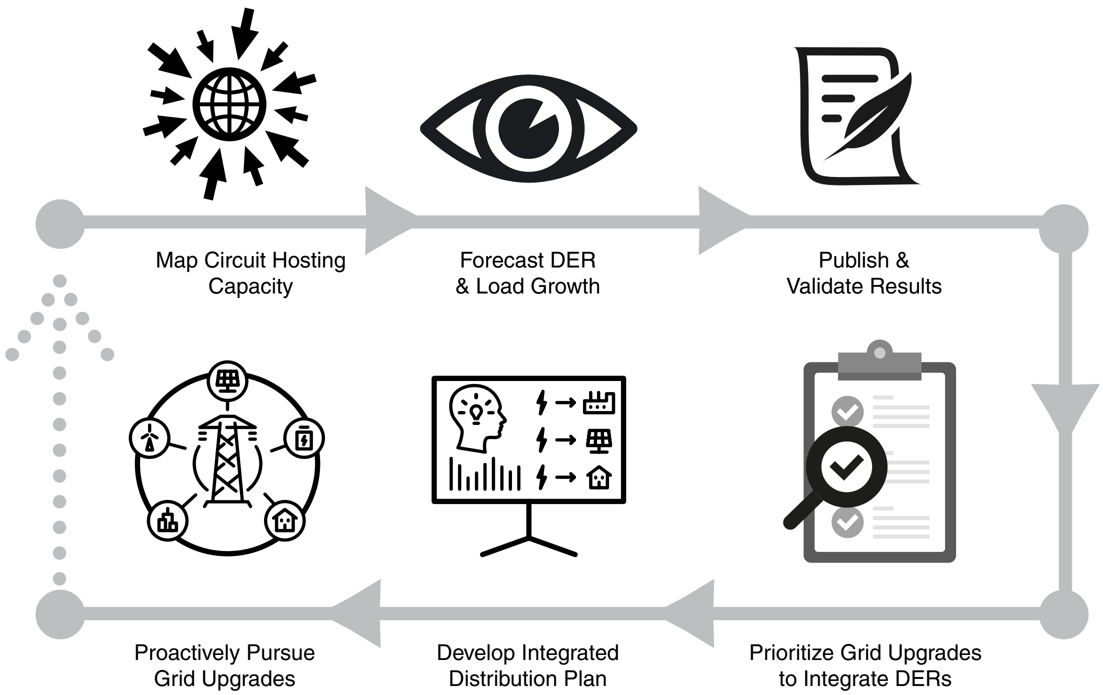


Figure 7. Integrated Distribution Planning (IDP)

layered with a corollary customer behavior analysis to see what impact, if any, such a change would have on the needs and capabilities of the distribution system under certain adoption scenarios. While this concept is not yet being implemented, there is potential to utilize the HCA in conjunction with other system planning tools to better understand how various policies and shifts in customer behavior can alter the distribution grid (which in turn should inform the long-term planning process). This aspect of the planning use case is currently under consideration in the long-term refinements phase of California's ICA working group where parties are discussing its feasibility and value and whether the existing methodologies are suited to providing accurate results for this use.[54]

3. State Experiences with the Planning Use Case for HCA

Among the states and utilities currently exploring HCA as part of their grid modernization proceedings, most have identified a role for hosting capacity in the planning process, but none have defined the planning use case with specificity. In New York, the Joint Utilities have been vague in setting forth planning as an explicit HCA use case and in providing information on how they intend to use the results of HCA to inform or improve the planning process.[55] Likewise, even after some discussion, the ICA working group in California concluded that while there was agreement that a planning use case was valuable, there needed to be further refinement of its details in order to properly evaluate the methodologies used to serve the use case.[56] As a result, stakeholders in both states have not yet had the opportunity to fully review and provide feedback and guidance on the HCA methodology most appropriate to support planning goals.

As with the interconnection use case, states are likely to get the greatest benefits from the HCA in the planning context if they clearly consider the goals of the distribution planning process and articulate a vision for how the HCA will be used to help achieve those goals. As states and utilities work to update distribution planning protocols in response to the demands and changes of the evolving electricity grid, the HCA should be considered an important tool to help achieve a more efficient, equitable and reliable grid.

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C. A COMPLEMENTARY FUNCTION: OPTIMIZING LOCATIONAL BENEFITS OF DERS

DERs have the potential to provide a range of electrical services beyond generation, capacity, and storing energy for later use. These include increasing transmission and distribution capacity, voltage support, reliability and resiliency services, equipment life extensions, and ancillary services.[57] As Southern California Edison has reported, by providing these services, DERs can increase the hosting capacity of feeders and "offset some of the load growth in an area and mitigate or even eliminate the need for capital-intensive upgrade projects."[58] DERs also provide additional environmental and public health benefits.[59] However, DERs will have greater energy, capacity, and grid values in some locations than others, depending on the characteristics and needs of the feeder and on the range of electrical services that the particular DER can provide.[60] When DER siting is effectively matched to grid needs, the DER customer, the utility, consumers, and other DER interconnection applicants all benefit.

Recognizing that the benefits of DERs may be, in some cases, location-specific has led some states to begin to develop tools to assess and identify values for DERs at precise locations on their distribution system. Separate from HCAs, locational benefits analyses can in theory be used to facilitate the matching of DER siting with grid needs by assigning greater or lesser value to DERs based on the location-dependent benefits they provide.[61] When the results of locational benefits analyses are combined with accurate hosting capacity and DER forecasting results, utilities and states will theoretically have a more robust suite of tools that can be used to deploy, direct and incentivize DERs to "optimal" grid locations (low cost and/or high benefit locations). Using these tools, programs and tariffs can then be designed to encourage DERs to operate in an optimal manner (bringing the greatest benefits to the grid) and provide compensation to the DER customers providing the benefits. "The objective is to achieve net positive value (net of costs to implement the DER sourcing) from DER integration for all utility customers."[62] However, it should be noted that extant state efforts on locational benefits analyses are not without controversy and there is not yet agreement on the methodology and assumptions underpinning such analyses (such nuances are important but are beyond the scope of this report, and thus are not discussed further).[63]

While locational benefits are not a direct use case for the HCA, since a separate modeling effort is required to identify these values on the system, the HCA is an important complementary tool to optimize locational benefits of DERs on the grid.

While locational benefits are not a direct use case for the HCA, since a separate modeling effort is required to identify these values on the system, the HCA is an important complementary tool to optimize locational benefits of DERs on the grid. At the same time that California has been working to develop the HCA, it has been developing a Locational Net Benefits Analysis (LNBA) that will identify locations where the low costs and/or high benefits of DER deployment favor increased DER activity.[64] California has proposed an updated distribution planning process that will combine the HCA with DER forecasts to develop an annual picture of the grid updates needed to support DER growth.[65] DER providers would then have an opportunity to propose DER solutions to grid needs, based on the HCA and the LNBA.[66] California may explicitly direct utilities to prioritize grid upgrade projects at locations that have both low hosting capacity and high net benefits.[67] New York is working on a similar effort through their Value of Distributed Energy Resources (VDER) proceeding. There, the state has begun to implement a valuation framework aimed at more granular determination of the temporal and locational values of DERs.[68] While the state has not yet taken this step, it could eventually pair the VDER with New York's HCA. This location-based valuation information will allow customers to assess the full costs and benefits associated with potential DER sites and direct their efforts to the most cost-effective locations.

IV. Select a Hosting Capacity Methodology Suited to Defined Use Cases

After selecting and defining use cases, the next process steps are to develop an HCA methodology (or methodologies) most appropriate to the use cases and to select criteria for implementation. Regulators play a critical role in both these steps. Clear and specific guidance from regulators ensures that the HCA effort does not become balkanized, with each utility employing a different methodology with varying suitability to statewide use cases. Regulators can also require that the methodologies and assumptions are transparent, thus ensuring the HCA produces results that are informative and instill confidence in how they are derived. Importantly, regulators also play a critical role in ensuring that the HCA is designed to address and achieve state energy policy goals.

To ensure HCA efforts are meaningful for all involved stakeholders and end-users, regulators should set up a process through which they work with utilities and stakeholders to select and refine HCA methodologies and set forth implementation rules. Ideally, this process should involve one or more working groups consisting of utility and non-utility participants with oversight from regulators to guide the HCA development. Utility tests of HCA methodologies can help the working group evaluate and refine the methodologies to meet identified use cases. Regulators should also create a process to improve on the selected HCA methodology over time and establish clear timelines for utilities to meet near and long-term HCA goals.

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A. THE METHODOLOGIES: STREAMLINED, ITERATIVE, AND STOCHASTIC HOSTING CAPACITY METHODS

There are an array of HCA methodologies under development and more likely on the horizon. For ease of discussion we have identified three primary methodological categories: streamlined, iterative and stochastic. They are briefly defined as follows:

- **The streamlined method** applies a set of simplified algorithms for each power system limitation (typically: thermal, safety/reliability, power quality/ voltage, and protection) to approximate the DER capacity limit at nodes across the distribution circuit.[69]

- **The iterative method** directly models DERs on the distribution grid to identify hosting capacity limitations. A power flow simulation is run iteratively at each node on the distribution system until a violation of one of the four power system limitations is identified.[70] The iterative method is also sometimes referred to as the detailed method.

- **The stochastic method** starts with a model of the existing distribution system, then new solar PV (or other DERs) of varying sizes are added to a feeder at randomly selected locations and the feeder is evaluated for any adverse effects that arise from this random allocation. The results are a hosting capacity range.[71]

While there is overlap between the methods, there is still considerable variation among the three methods in terms of basic methodological choices, results, and assumptions. Utilities and commissions may be tempted to simply select the HCA methodology that will be the least costly and least computationally complex to implement. For instance, the New York Joint Utilities and Xcel Energy in Minnesota have selected HCA methodologies based on a version of the streamlined hosting capacity method developed by EPRI—the DRIVE tool—possibly due to its computational efficiency relative to iterative methods and the off-the-shelf nature of the tool being offered by EPRI.[72] But experience from California's detailed HCA demonstration projects has shown that the version of the streamlined method used by the California utilities was not appropriate for certain use cases, particularly interconnection. It is not yet clear whether any differences between the streamlined method used in California and the one deployed by EPRI result in appreciably different outcomes, but it is clear that EPRI has not identified interconnection as a direct use case for the DRIVE tool.[73]

The failure to select an appropriate HCA methodology at the outset can lead to wasted time and money for utilities and their ratepayers if utilities must later develop and deploy a different method that is better suited and/or more appropriate to achieving the identified goals or policy objectives. As such, it is important to carefully select the methodology best suited to the state's use cases and regulatory goals. To the extent a state or utility chooses to pursue a more phased approach to HCA, a clear framework for moving through the phases and a process for iterating on and improving the HCA over time should be identified at the outset of the effort.

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It is important to recognize that the HCA methodologies available today will likely evolve and improve over time with increased use as a variety of utilities deploy them. As multiple utilities deploy and trial different methods, stakeholders are learning more about the benefits and drawbacks of each. However, over time it will likely be far less resource intensive if a consistent methodology (or methodologies) can be available and applied “out of the box” for utilities beginning the process. EPRI’s DRIVE tool is a step in this direction. However, as a proprietary tool, questions remain about its capabilities and level of transparency that need to be resolved before it is clear whether this is an appropriate methodology for widespread deployment. Despite the fact that extant tools are apt to evolve over time, state regulators should not hesitate to begin the process of initiating stakeholder efforts and proceedings to define goals, identify use cases, assess utility needs, and set a timeline for statewide implementation. HCA is not only a timely tool that all states and utilities should begin exploring, but early efforts will establish an important foundation of transparency, accuracy and stakeholder consensus once the tool is adopted and implemented. Rather than wait for the perfect HCA methodology to emerge, regulators can take initial steps to gain familiarity and understanding of the different HCA methodologies, their function, their capabilities, and their limitations.

Along with selecting a methodology, regulators should carefully consider the criteria that will guide its implementation.

B. IDENTIFY CRITERIA TO GUIDE IMPLEMENTATION OF HCA

Along with selecting a methodology, regulators should carefully consider the criteria that will guide its implementation. For instance, regulators may wish to consider:

(1) **Phasing:** Regulators may consider whether to create a phased roadmap for implementation of HCA. New York utilities, for instance, have proposed a four-stage roadmap, “with each subsequent stage increasing in effectiveness, complexity, and data requirements.”[74] If a phased approach is used, regulators should ensure that the tools developed and deployed in earlier stages are compatible with the goals of later stages, and the phasing reflect the priority of the state’s goals.

(2) **Frequency of updating:** Will HCA results be updated in real-time, weekly, monthly, annually, or on some other time scale? For interconnection automation and streamlining purposes, very frequent HCA results across the entire grid may be necessary. For planning purposes, less frequent updating may be required if scenarios are only needed on a periodic basis (such as annually or as appropriate). Regulators may also consider regular updating (weekly or monthly) of results for the entire grid, coupled with targeted updating of particular grid segments for interconnection purposes. For instance, the hosting capacity of the entire grid could be mapped annually, and these results could be updated incrementally each time the hosting capacity of a feeder is assessed as part of the interconnection process. The frequency of updates should align with the goals and use cases, though tempered by cost and technical feasibility.

(3) The extent of the grid covered by HCA: Will the entire distribution grid be mapped at the outset, or will only high priority portions of it be mapped initially, coupled with incremental expansion until the entire grid is analyzed? The California utilities, for instance, mapped all three-phase lines in the test areas and are exploring expanding the HCA to single-phase lines and reserving for future analysis interactions with the transmission system (such iteration of the tool is a good example of how HCA efforts can be phased over time to become more sophisticated and robust). Xcel Energy in Minnesota has proposed excluding feeders serving low voltage networks in downtown Minneapolis and St. Paul areas, which have not been previously modeled.[75] Regulators should ensure that the HCA methodology is scalable so that, even under an incremental approach, the full grid can eventually be covered.

(4) DER Neutral: Making HCA agnostic to the type of DER will ensure that it remains useful as technologies and their market saturation change over time. Agnosticism is also essential for the HCA to be capable of identifying ways to expand hosting capacity or use non-wires alternatives. Under direction of the California PUC, California utilities have, for this reason, provided "agnostic" hosting capacity values "that can be used by DER providers to analyze other DER portfolio combinations."[76] They have also made an "ICA translator" available to users to determine the hosting capacity values for different types of DERs.[77] In contrast, New York and Minnesota are just focusing on solar of a certain scale in their initial analysis, and it appears that Pepco's approach is also focused only on PV.[78]

(5) Transparency Criteria: Regulators should carefully set forth the criteria for ensuring transparency in the selected HCA methodology and its results. For instance, utilities should be open about the methodology selected and any assumptions built into it. Ideally, third-parties should be able to independently test and validate the methodology to ensure its accuracy and reliability. Where multiple utilities operate in a state, regulators may also consider requiring utilities to run their respective methodologies on a test circuit and compare results. Utilities should also be open about any limitations in their analysis—i.e., to what extent it is limited in capturing the HCA under highly distributed DER scenarios, whether anticipated DER additions are built into the analysis, whether certain feeders or feeder types are excluded, whether the methodology relies on any heuristics, etc.[79]

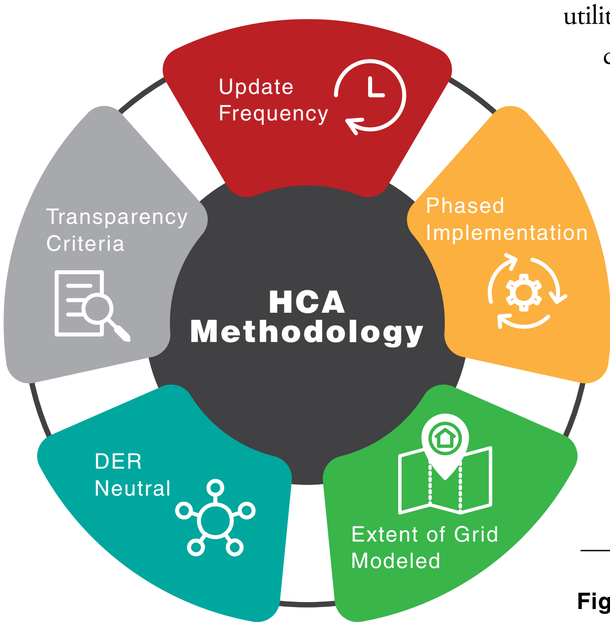


Figure 8. Criteria to Guide Implementation of HCA

C. VALIDATE RESULTS

Transparency in the methodology and assumptions and ready access to HCA results will ensure that they can be easily validated and any problems with the methodology identified and resolved. Ideally, sufficient information about the methodology should exist so that a third party could perform an independent analysis to validate the results reached by utilities. Running and publishing results on test circuits and comparing actual interconnection study results will also assist in the validation process. In states like California with multiple utilities, regulators may consider requiring the utilities to run their HCA analysis on a test circuit and publicly compare results. In doing so, the California utilities were able both to confirm that they are aligned on methodology, producing largely consistent results on the test circuit,[80] and to identify areas where their different software packages and model simulations led to discrepancies so that any bugs can be worked out.[81]

D. IDENTIFY HOW DATA WILL BE SHARED

Data sharing is a key factor shaping the evolution of the electricity grid, and the sharing of data produced by the HCA will significantly impact its value as a next generation grid tool. In the hosting capacity context, data sharing enables the validation of results, allows customers to evaluate potential locations for DER siting and enables third parties to compete in offering non-wires alternatives for grid upgrades to expand hosting capacity.

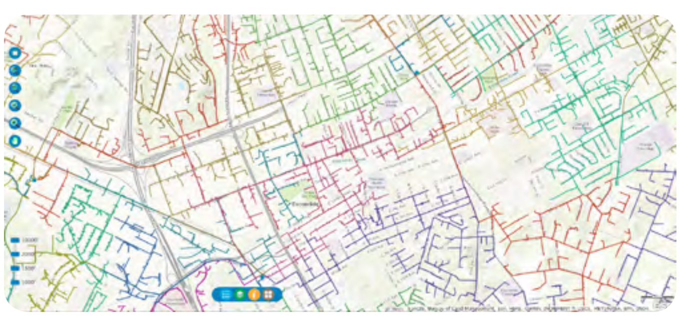
Regulators will need to consider the most useful manner for utilities to publish and display hosting capacity data.

1. Hosting Capacity Maps

Maps illustrating the hosting capacity of grid sections can be a useful tool to enable easy visualization of hosting capacity results.[82] Maps provide a high-level display of hosting capacity values on feeders throughout a circuit. Early examples of hosting capacity maps have employed color-coding of line segments and feeders according to their hosting capacity range to help customers easily identify those grid sections where DERs can be most readily interconnected.[83] They have also used quick-display boxes, allowing the viewer to easily see summary hosting capacity information for a given node or feeder.

Figure 9. Sample Hosting Capacity Maps

Source: *SDG&E, Demonstration A, Integration Capacity Map available at:https://energydatarequest.socalgas.com/ICM/*



Considerations regarding maps include:

- **Visual Display Format** What kind of color-coding, if any, should the maps employ? If color-coding is required, will all the utilities in the regulated territory be required to use a uniform color-coding system or can they select a unique color-coding system tailored to their service area?

- **Data Displays** If quick-display boxes are used, what information should utilities be required to display in those boxes? Should, for instance, the boxes include the hosting capacity value for each power system limitation, or only the overall hosting capacity at that point? Should the boxes also include basic circuit information in addition to the hosting capacity values? Will quick-display boxes be available for every node on the circuit or at less granular levels like line segment or feeder?

- **DER Technology** Will the hosting capacity maps only display data for a uniform generation profile or a standard solar PV profile? Or can they instead be filtered by the viewer to display information relevant to different DER technologies so that, for instance, different color-coding and data would appear depending on whether the viewer selects energy storage, PV with or without advanced inverters, or another DER type. If the latter, what kinds of DER technologies will be available for the viewer to select?

- **Which Data** If a blend of hosting capacity methodologies is used, which hosting capacity results will be displayed on the map? How will results be displayed if multiple scenarios are run for a circuit?

- **Data Format** Will the map data be made available in standard GIS formats?

2. Downloadable Hosting Capacity Data

In addition to the maps, DER customers may need access to more granular underlying data than can be easily provided through a map to file an interconnection application or design a DER to fall under hosting capacity limits. Separate considerations apply to production of maps and underlying data.

Considerations with respect to provision of underlying data include:

- **Access** Will the underlying data be publicly accessible? How soon after the HCA is run will the publicly available data reflect the new results? Will old results be archived in a publicly available manner? Will the data be free for all users, or will there be access-related costs?

- **Content** What information will be provided in the underlying data? I.e. what hourly load profile data will be available? Will the underlying hosting capacity criteria violations be provided on the map or through the underlying data? What other types of data might be necessary to share in order to make the HCA results meaningful and actionable?

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Figure 10. Sample Load Curve Data

Source: *SDG&E, Demonstration A, Integration Capacity Map, available at: https://energydatarequest.socalgas.com/ICM/*

- **Data Format** In what format(s) will the data be made available (e.g. a downloadable database, a JSON or CSV text file, etc.)? Alternatively or additionally, will the data be provided in a machine queryable fashion (e.g. through a RESTful Application Program Interface (API))? A RESTful API would allow users to query a web service running on a server operated by the utility, facilitating tailored requests for timely access to relevant raw data.[84]

- **Documentation** How will the data format or API be documented and how will the documentation be made available? Data files can be difficult to parse if the organization of the data is not well documented—for instance if the permissible values of a data field are not explained.

- **Usability** If downloadable databases are used, how will the databases be engineered to facilitate usability by customers and other stakeholders? Will they be annotated so that, for instance, a developer could identify locations by hosting capacity value and area screens?

- **Granularity** Highly granular data across a distribution circuit can result in large data files that could be practically difficult for utilities to store and users to download. An API could help overcome some of these issues. If downloadable files are instead provided, what level of granularity is appropriate to give customers the information they need without rendering the data inaccessible due to its volume? Will, for instance, hosting capacity values for every hour of a load curve be provided or rather a single value for a load curve? Are there other methods available to help manage the data efficiently without unduly constraining access?

- **Data Privacy** Should privacy concerns constrain access to the data? While it is impossible to provide perfectly anonymized data, can the data be sufficiently anonymized to overcome privacy-related constraints? Will there be a process in place to remove personally identifiable information if highly granular underlying data is provided?

- **Security** Are there any cyber or physical security considerations to take into account when sharing HCA data? If concerns are raised by utilities or others, the specific information that raises concerns should be identified so that parties can evaluate whether the HCA data sharing poses real risks, and if so, how best to manage those risks.

V. Stakeholder Engagement Strategies

A number of best practices for engaging stakeholders in the HCA development and implementation process can be garnered from the experiences of states like California, Minnesota and New York. Principal among lessons learned are:

(1) **Early and Consistent Engagement.** Stakeholder should be engaged as early as possible in the process, before critical path decisions are made. If regulators permit utilities to commit to a specific HCA method in advance, stakeholders engaged later may raise issues and insights, which show that method not to best suited to the state's needs, leading to wasted time and expense. To avoid this pitfall, stakeholders should be engaged in the process of setting and refining the uses cases and goals for HCA and involved in every step of the HCA development and implementation process thereafter, including in selecting and refining the HCA method used, in evaluating results, and in updating it as lessons are learned and methodologies improved. The back-and-forth dialogue that occurs in a working group can be particularly constructive, but this feedback can also be valuably obtained through a well-structured comment process.

(2) **Open Membership.** Membership in the stakeholder group should be open to all those who wish to participate to ensure diversity of perspectives and optimal buy-in from interested and affected communities. It may be possible to designate representative members from different groups of stakeholder interests to better manage input, but this needs to be done without unnecessarily constraining party participation. If written comments are used, there may need to be active efforts by the Commission to elicit sufficient participation to ensure an adequate range of perspectives are considered.

(3) **Neutral Facilitation and Reporting.** The stakeholder group facilitator should be carefully selected. Ideally, the facilitator will be a neutral party, either selected from within the Public Utility Commission or from a third party, rather than selected and appointed by the utilities. The facilitator should also have experience and skills in stakeholder engagement. The facilitator should ensure effective and neutral reporting of stakeholder group outcomes, including by producing detailed minutes and by either producing reports herself with stakeholder input or coordinating production of reports by involved stakeholders.

Stakeholders should be engaged in the process of setting and refining the uses cases and goals for HCA and involved in every step of the HCA development and implementation process thereafter, including in selecting and refining the HCA method used, in evaluating results, and in updating it as lessons are learned and methodologies improved.

California's Distribution Resource Plan working groups provide a useful model. The ICA (i.e., hosting capacity) working group is facilitated by a third-party consultant paid for by the utilities, but California PUC staff has oversight responsibility for the group and could assume direct management at any point to ensure meaningful stakeholder engagement.[85] The working group does its own reporting, with all stakeholders helping to draft the group's reports such that conflicting viewpoints are accurate captured for consideration by the PUC. The neutral facilitator guides the production of the reports, and while utility representatives engage in iterative discussions with the stakeholders and contribute their insights and feedback, they do not filter the reports' recommendations and conclusions. As an alternative, a working group could produce a non-utility stakeholder specific report. Utilities would then have an opportunity to file their own reports and the commission would have the two perspectives for comparison and reference in their decision-making.

If written comments are used in lieu of a working group, it is important to ensure stakeholder comments are considered by the utilities and that the decision makers are provided with a complete understanding of party perspectives.

(4) **Active Utility Engagement.** Utilities should be required to actively participate in the stakeholder process. When utilities participate only passively, stakeholders may not be informed of utility concerns and/or may feel that their concerns are not being critically considered by the utilities. There should also be checks in place to ensure that utilities are meaningfully considering stakeholder insights and revising their methods where appropriate based on those insights.

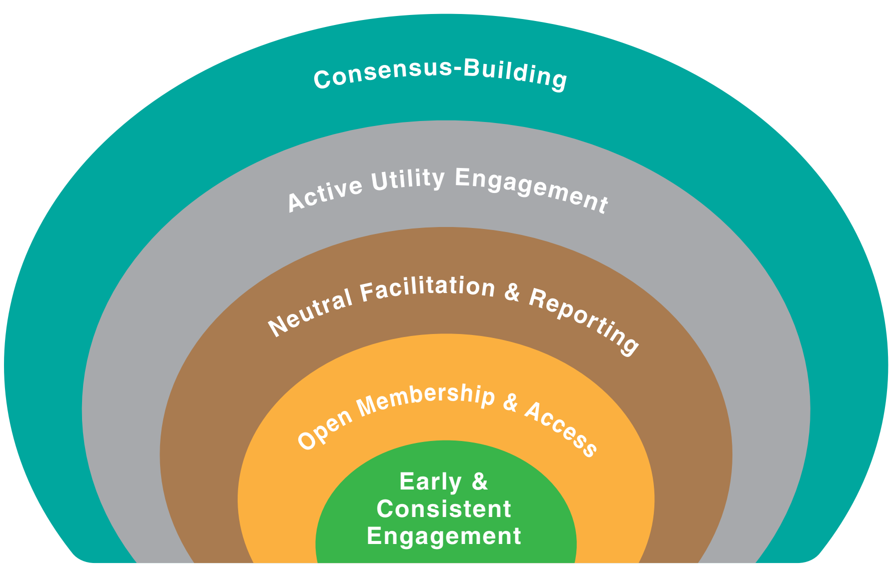
In the California ICA working group, the utility and non-utility stakeholders have engaged in productive, iterative, and ongoing negotiations, with the utilities fielding stakeholder questions, responding to recommendations and concerns, and dialoguing with stakeholders about possibilities during in-person and web-based working group meetings and in written form. This interactive process has enabled non-utility stakeholders to play a meaningful role in shaping the use cases and criteria for and the selection of an appropriate HCA methodology in California. It also helps stakeholders understand and often support utility approaches that might otherwise seem objectionable. By contrast, stakeholders in New York's Reforming the Energy Vision engagement groups reported that utilities had already made critical decisions before talking to stakeholders at engagement group meetings. And when stakeholders provided input, the utilities did not report back during the working group process about what input would or would not be taken into account, thereby allowing for the iteration and discussion that could lead to consensus. As a result, the meetings seemed to serve more as an opportunity to inform stakeholders of utilities' plans than a meaningful opportunity for stakeholders to help shape the outcome of the process.[86]

(5) Consensus-Building: Regulators and facilitators should ensure that the stakeholder process maximizes opportunities for stakeholders to actively voice their perspectives and concerns. Working group meetings and discussions should promote active dialogue among stakeholders in order to build consensus. Where there are areas of disagreement, there should be opportunities to communicate divergent views to utilities and regulators, including through stakeholder reports. If a hosting capacity-specific working group is convened as part of a broader grid modernization proceeding, regulators should ensure that there are opportunities to coordinate with working groups addressing other topic areas. In the New York REV proceedings, the narrowness of the engagement group topics impeded stakeholders in engaging effectively on issues with cross-subject relevance, such as tying HCA development to interconnection and planning and to questions regarding overall grid data access.[87]

(6) Open Access. Access to stakeholder meetings and results should be made as easy as possible. Measures to optimize access include noticing stakeholder meetings well in advance, holding meetings in a neutral location, establishing a mix of in-person and telephonic conferences (New York, for instance, held three in-person and three telephonic meetings, all run by a third-party facilitator), employing technology to maximize meaningful participation, and maintaining detailed minutes. Minutes, reports, and other stakeholder group documents should be posted in in an accessible electronic forum to allow interested parties to keep track of proceedings.

Regulators and facilitators should ensure that the stakeholder process maximizes opportunities for stakeholders to actively voice their perspectives and concerns.

Figure 11. Regulatory Stakeholder Engagement Strategies



VI. Conclusion: Realizing the Promise of HCA for All Ratepayers

As more states and utilities work to modernize the electric grid and to proactively integrate and optimize DERs on the electric system, new tools and approaches are needed. HCA has emerged as a key tool that allows utilities, regulators, and DER customers to make more efficient and cost-effective choices about deploying DER technology on the grid. HCAs can also speed up the process of interconnecting DERs since steps to expand hosting capacity will have been taken, where appropriate, prior to applications being submitted. Ultimately, as utilities plan for and pursue (or solicit from third parties) grid infrastructure improvements over time, HCAs can help ensure that DERs are optimized, not discouraged, on the system as an integrated and functional feature of affordable, quality and reliable electricity service provided to all ratepayers.

Regulators play an important role in guiding and overseeing utilities as they prepare HCA on their distribution circuits. Given the vanguard nature of this topic, regulators can and should seek to inform their efforts with lessons from the handful of states and utilities that have begun to prepare hosting capacity analyses. Over time the software, methods and assumptions may become standardized, but in the early stages of HCA it is important that states conduct a thorough process to understand and properly vet their rollout.

Paying close attention to the process underpinning HCA efforts will help regulators realize the full promise of HCA for all ratepayers. The key process steps, recapped, are as follows:

(1) Establish a stakeholder process to work with utilities and other interested stakeholders to select, refine and implement the HCA. Ideally, this process should involve one or more working groups consisting of utility and non-utility participants with oversight from regulators to guide the HCA development. Regulators should also retain a process to improve on the selected HCA methodology over time and establish clear timelines for utilities to meet near and long-term HCA goals.

Regulators play an important role in guiding and overseeing utilities as they prepare HCA on their distribution circuits. Given the vanguard nature of this topic, regulators can and should seek to inform their efforts with lessons from the handful of states and utilities that have begun to prepare hosting capacity analyses.

(2) **Identify criteria to guide implementation of the HCA** at the outset. Working through the established stakeholder process to identify and answer key questions regarding the scope, duration, and other key elements of the HCA can help ensure a more efficient process throughout (and greater buy-in from all involved). The *frequency of updating* the HCA results, the *extent of the grid covered by HCA*, and *criteria for ensuring transparency* in the selected HCA methodology and its results are all important to discuss and define. In addition, regulators may consider whether to create a phased roadmap for implementation of HCA, depending on the level of sophistication of the utilities and the timeline for achieving state energy goals. However, care should be taken not to create an endless implementation timeline that quickly becomes obsolete or fails to miss near term opportunities for deployment and use.

(3) **Select and define the use cases for the HCA**, with input from diverse stakeholders, ensuring they are clearly designed to address and achieve identified goals, including state energy policy goals. These use cases should inform and guide the development of an HCA methodology and its implementation. There are two major HCA use cases—interconnection and planning—and a complementary function of HCA—optimizing the locational benefits of DERs. As regulators and utilities consider undertaking an HCA, it is critical that all stakeholders carefully consider and select desired use cases for HCA together at the beginning of the process. Defining use cases ensures that the cart is not put before the horse and will also prevent potentially costly and inefficient undertakings that do not produce useable results.

(4) **Develop an HCA methodology (or methodologies) most appropriate to the use cases**, providing clear and specific guidance and ensuring that the methodologies and assumptions are transparent and informative to all involved stakeholders and end-users. Regulators should ensure that the HCA methodology is scalable so that, even under an incremental approach, the full grid and range of DERs can eventually be analyzed. Currently, most HCA methodologies fit within three categories: streamlined, iterative and stochastic methodologies (though more are under development, and each individual application may have important variations). Importantly, different methodologies can result in different hosting capacity values due to different technical assumptions built into the models. Given the variety of factors that affect the grid's ability to host a wide range of DERs, it is necessary to select a well-considered methodology for determining hosting capacity based upon its intended use.

(5) **Validate the results** of the HCA over time. As with any model or analysis, real-world validation can help improve accuracy and functionality over time. Transparency in the methodology and assumptions and ready access to HCA results will ensure that they can be easily validated and any problems with the methodology identified and resolved. Ideally, sufficient information about the methodology should exist so that a third party could perform an independent analysis to validate the results reached by utilities. Regulators will need to consider the most useful manner for utilities to publish and display hosting capacity data, and set milestones over time to evaluate the performance of the HCA, relative to identified goals.

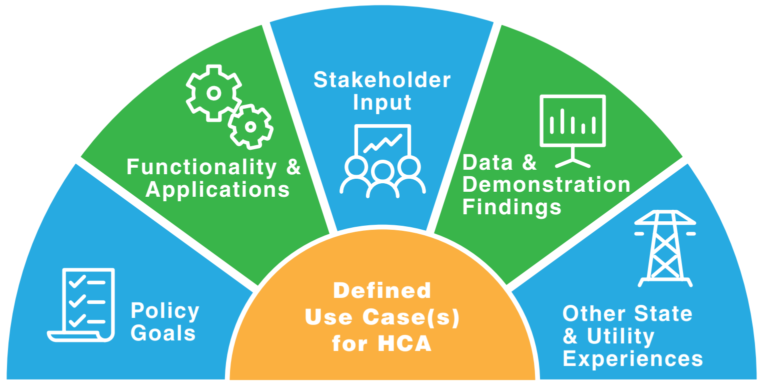


Figure 12. Key Elements to Defining Use Case(s) for HCA

In addition to the above process steps, regulators should keep in mind other key considerations, noted in the report, as they help guide and oversee the implementation of HCAs.

First, the HCA methodologies available today will likely evolve and improve over time, particularly as more utilities adopt and deploy HCA and trial different methods. Still a nascent grid modernization tool, the benefits and drawbacks of different HCA methodologies are being revealed, and likely will become even more apparent with time. Yet rather than wait for the perfect HCA methodology to emerge, regulators can take initial steps to gain familiarity and understanding of the different HCA methodologies, their function, their capabilities, and their limitations. Given the substantial investment in time, energy, and resources that HCA efforts require, there is value in taking the time early in the process to ensure that the tool being developed is capable of meeting identified objectives. Questions or concerns about what an HCA can do should be addressed before widespread implementation, lest substantial resources be invested in something that proves invaluable or ambiguously useful.

Second, requiring consistency in approaches and methodologies among utilities (where there are multiple utility services territories within a state) will help simplify the implementation and oversight process, while also ensuring a more consistent and efficient utilization of this tool among DER customers. Balkanized efforts, with each utility employing a different methodology with varying suitability to statewide use cases, will likely result in more confusion among those seeking to use the HCA and reduce efficiencies for all, including utilities and regulators. Consistent methodologies among utilities also allows for peer learning and exchange of information among utilities, which will help improve the accuracy and functionality of the HCAs over time.

Third, given swift changes to technologies, performance, and markets, HCAs should be agnostic to the type of DER to ensure that it remains useful over time. Technology agnosticism can also help utilities identify opportunities to expand hosting capacity with other DERs and deploy non-wires alternatives as part of utility grid upgrades and investment plans.

HCAs should not be developed or implemented in a vacuum, and should be considered in the context of other policy choices and how they may impact how DERs are deployed. Similarly, the HCA can and should be used as a tool to evaluate and understand how the hosting capacity of the distribution system might change as a result of these policies.

Fourth, data sharing remains a key factor shaping the evolution of the electricity grid, and the data collected and generated as part of an HCA will help utilities, regulators, and DER providers and customers better capture the diverse value streams of DERs. However, data sharing requires attention to related issues such as customer confidentiality, access permission, and cyber security. In this data-driven era, regulators will be increasingly tasked with balancing grid optimization, transparency and competition, consumer protections and grid security. Yet, concerns surrounding data sharing can and should be managed proactively and should not be a reason to not pursue HCAs or related efforts.

Lastly, HCAs should not be developed or implemented in a vacuum, and should be considered in the context of other policy choices and how they may impact how DERs are deployed. Similarly, the HCA can and should be used as a tool to evaluate and understand how the hosting capacity of the distribution system might change as a result of these policies. As consumers and the market responds to new programs, policies, and price signals, so too should the HCAs reflect the anticipated and planned changes to DER adoption. More robust DER forecasting methodologies will need to be developed in order to provide greater granularity and accuracy of the HCA.

As state regulators, utilities, and other involved stakeholders work to build an electricity grid better suited for the challenges and opportunities of the 21st century, the HCA will be a formative tool. Not only will HCA be a critical vehicle to improve the planning and operations of the grid, but, if deployed with intention, may also function as a bridge to span information gaps between developers, customers and utilities, enabling more productive, efficient, and cost-effective grid solutions for the benefit of all ratepayers. Regulators, with this report in hand, can provide the leadership and guidance needed to ensure the process, function, and implementation of HCA support and enable the critical grid transformations underway.

Appendix A: Case Studies on Current State and Utility Approaches to Hosting Capacity

CALIFORNIA CASE STUDY

In the Fall of 2017 the California Public Utilities Commission (CPUC) authorized full rollout of HCA across the three major IOU territories.[88] The path that California went through to arrive at this decision is both informative and instructive for other states that may be undertaking similar efforts. The process started in 2013 when the California legislature passed a bill requiring the IOUs to identify optimal locations on their grid for DERs.[89] In order to achieve this goal the CPUC determined that the utilities needed to develop "Integration Capacity Analyses" or ICA (California's name for HCA) for their territories.[90] The CPUC first required each of the utilities to develop and roll out an ICA on at least a few test feeders using a common methodology as part of their Distributed Resources Plans that were due in July of 2015.[91] From the outset, the CPUC indicated that the projects should look to support both planning and streamlining of the interconnection process.[92]

Although the CPUC specified that a common methodology was required, the California utilities—Pacific Gas & Electric (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison (SCE)—initially elected to implement different HCA methodologies in their Plans. PG&E did an initial rollout using what they called the "streamlined" method, while SDG&E and SCE utilized an "iterative" method. Following review of these Plans, the CPUC authorized the IOUs to collaborate with a stakeholder Working Group[93] to implement Demonstration Projects for the ICA that would further refine the methodologies and details prior to full system rollout. Intending to standardize their methods, the PUC initially ordered all three to implement a streamlined HCA methodology. However, after SDG&E and SCE raised significant concerns with the accuracy of the streamlined approach that had been initially deployed by PG&E,[94] the PUC, at the Working Group's urging, ordered the demonstration projects to test and compare both the streamlined and iterative methods.[95]

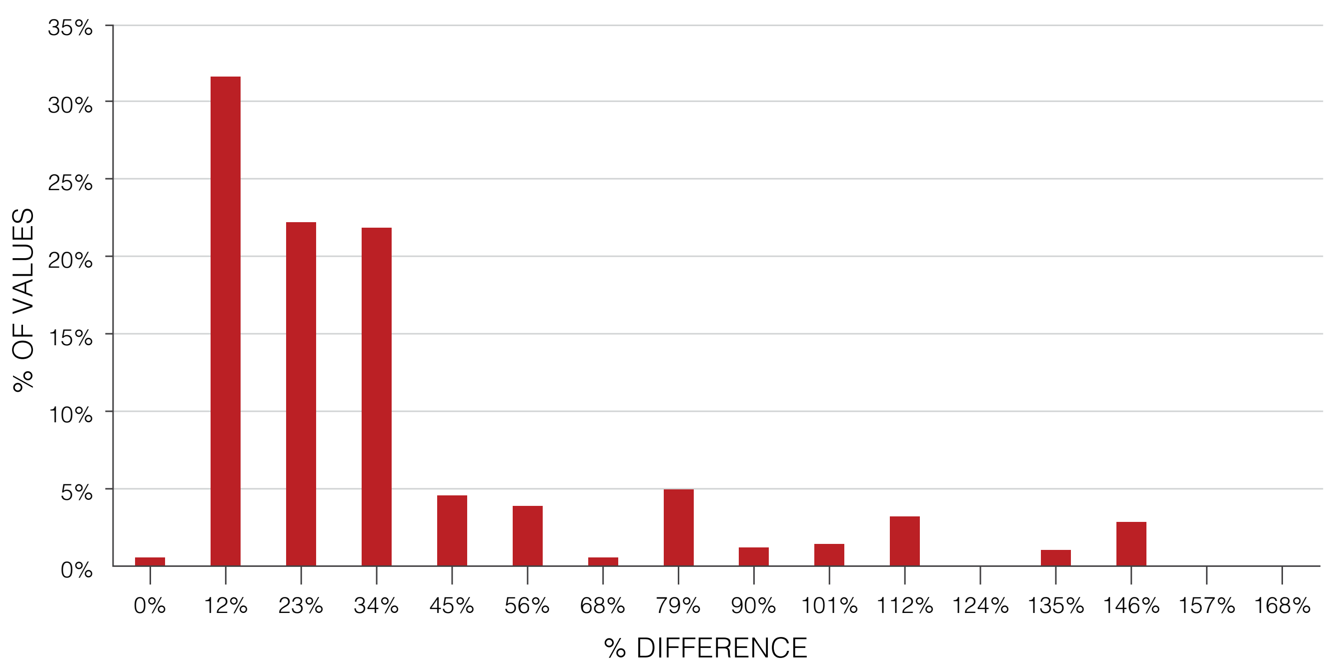
For the demonstration projects, each IOU performed an iterative and streamlined analysis of a portion of their distribution grids in an urban and a rural demonstration area within their respective service territories and additionally ran both analyses on a single test feeder to compare results and identify discrepancies across IOUs. For roughly seven months the IOUs met regularly with the Working Group to refine the details and work through challenges encountered in their development. In December 2016, the utilities published reports analyzing their results and released the HCA data through maps and downloadable data files. Regulators in other states can utilize these results and data to guide HCA methodology selection without replicating the California studies.

The California results revealed the essential tradeoff between the two approaches to be accuracy vs. computational speed. That is, the iterative method optimizes precision because it measures the actual technical capacity of the system, and it proved to be particularly well suited to complex feeders "where the streamlined approach may have difficulty in streamlining the dynamic voltage device operations on longer circuits."[96] The streamlined method, by contrast, can provide only a rough approximation of hosting capacity levels due to its reliance on abstract algorithms, however it is less data intensive and thus could allow more simulations to be run in a timely manner.[97] The discrepancy between the two sets of results varied by power system criteria and feeder location. For instance, SDG&E found that for thermal limitations, the results of the two methods were generally within 30% of each other, with the streamlined method typically resulting in a larger, but less accurate hosting capacity value.[98] By contrast, the results of the two methods were much further apart for the steady state voltage and protection criterion, with the streamlined method yielding more conservative hosting capacity values.[99] The difference in results was particularly pronounced for nodes close to the substation where the feeder's hosting capacity is at its peak and on feeders with higher numbers of voltage regulation devices.[100]

The degree of difference between the hosting capacity values returned by the two methods was surprising. For instance, while SDG&E found that the iterative vs. streamlined results differed by between 12 to 34%, the difference between the results on any one feeder could be as great as 146% (see Figure 13 below). With respect to computational speed, the streamlined approach proved to be significantly faster to perform than the iterative approach, though the discrepancy depended on software and hardware choices. PG&E, for instance, was able to reduce run times by using a combination of local machines and servers.[101] The use of cloud computing may further decrease computational times. The utilities were also able to lower run times by strategically reducing the number of hours and nodes being analyzed.

Figure 13. SDG&E Statistical Differences Between the Streamlined and Iterative Methods

Source: *San Diego Gas & Electric Company, R. 14-08-013, Demonstration Projects A & B Final Reports of San Diego Gas & Electric Company (U 902-E), Demonstration A—Enhanced Integration Capacity Analysis, p. 46 (Dec. 22, 2016)*



All three utilities concluded that the iterative approach is better suited for analyzing circuit conditions for interconnection purposes, although they shared concern about the computational demands of that approach.[102] By contrast, the utilities suggested that the streamlined approach may be more applicable for a planning use case because of its ability to efficiently perform scenario analyses.[103] As a consequence, the utilities initially recommended utilizing a blended approach, with iterative analysis used for interconnection and streamlined use for planning, and PG&E further suggesting that both methods should also be used together for the interconnection use case.

The Working Group intensively analyzed these results in making its recommendation to the CPUC on how to proceed. As part of this effort the group defined what the precise goals were for the interconnection use case and compared the ability of the different methodologies to achieve those goals. The Working Group found that due to the relative inaccuracy of the streamlined method that it was inadequate to support the goal of substantially automating the interconnection process for projects falling within the identified hosting capacity. All but PG&E agreed, thus, that the iterative methodology should be used for the interconnection use case. PG&E recommended using a combined method,[104] but the CPUC ultimately adopted the recommendation of the majority of the Working Group.[105]

With respect to the planning use case, the Working Group found that it required further development before it could adequately assess which methodology or combination of methodologies would best serve the needs of that case. The Group thus agreed to continue working on refining this use case during 2017 and a decision will come in 2018 which will determine how the ICA can be used to best achieve the refined goals of the planning use case.[106]

Refinement of the use cases and selection of the core methodology was not the only focus of the Working Group. The Group also worked with the utilities to agree upon how the results would be displayed on the publicly available maps, what data would be made available for download, and how to address particularly methodological hurdles regarding operation of voltage regulating devices, smart inverters and other system issues.

Regulators can learn a great deal from evaluating the California experience and results:

- The California experience illustrates the importance of a carefully designed and inclusive process for HCA methodology selection. While the demonstration projects ultimately used have been highly valuable, time and expense could have been saved by putting into place at the outset a process to compare HCA methods. This process made sense in California as this was really the first full rollout done through a public process, but the issues discussed are not unique to California and thus other states can likely jump ahead if they build on this experience.

- The California demonstration project results provide a helpful analysis of the tradeoffs between streamlined and iterative methodologies and a framework for evaluating their suitability to the different use cases. In general, they reveal that, between the two methods as designed at the time, only the iterative analysis produced accurate enough results for use in interconnection decision making. While the streamlined method may have value for planning because of its suitability for scenario analysis, it remains unclear whether the streamlined method can be made accurate enough for interconnection or planning purposes. As in other states, the lack of a precise definition and goals for the planning use case has impeded the ability to make this determination.

- Working groups and utilities should explore ways to revise methodologies to overcome obstacles. It may be possible to reduce hour and node profiles for the iterative method, for instance, to shorten computational times without unduly sacrificing accuracy. Likewise, different hardware choices (i.e. use of servers and cloud computing) can significantly speed up computing. Regulators should make sure that when utilities report on computational challenges, they also report on the expense associated with overcoming them.

- When tests of HCA methodologies are performed, raw data should be released along with analysis of results to help working group participants and third parties provide the most useful feedback.

- Dialogue between utility and non-utility stakeholders is critical in selecting and refining the HCA methodology and can be done in a constructive and collaborative manner with the right framework in place.

NEW YORK CASE STUDY

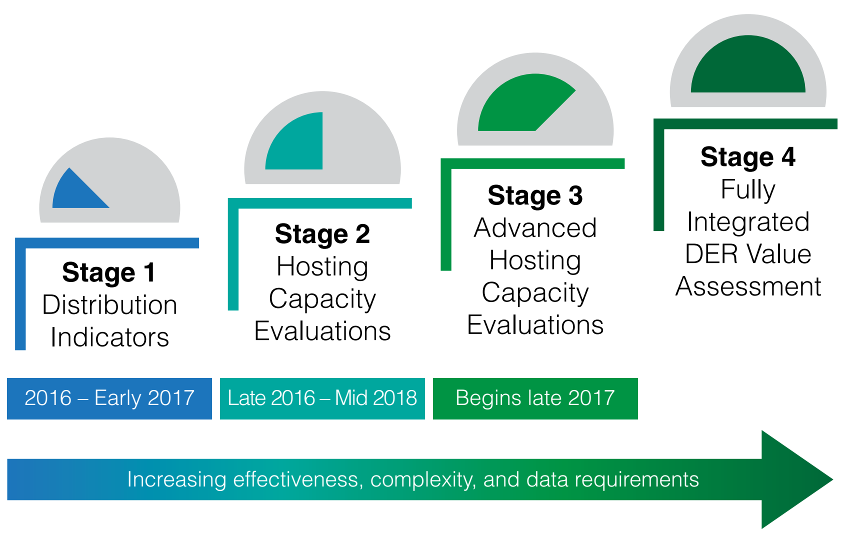
The efforts to develop HCA in New York arose as part of the state's Reforming the Energy Vision (REV) proceeding.[107] In 2015, the New York Public Service Commission (NY PSC) required the utilities to include hosting capacity efforts in their Distributed System Implementation Plans (DSIPs).[108] The NY PSC required the utilities to develop a common methodology and publish the known hosting capacity for all circuits on a map that includes relevant system information. The NY PSC did not initially specify the granularity of the analysis or the frequency with which it would be updated. Though the NY PSC alluded to the general value of having hosting capacity information, it did not identify use cases for the HCA to instruct the utilities in their selection of methodology or the ultimate functionality desired. The NY PSC ordered the utilities to engage with stakeholders around all aspects of their DSIPs, but did not require a specific structure for incorporating the feedback or for documentation of stakeholder input.[109]

The Joint Utilities[110] collaborated with the Electric Power Research Institute (EPRI) on the preparation of a paper that outlined the tiered approach the utilities would use to develop their hosting capacity analyses.[111] The paper and subsequent DSIPs identified that hosting capacity can be used to "inform" interconnection, planning and the identification of locational value.[112] The Joint Utilities chose to utilize EPRI's proprietary DRIVE tool,[113] which utilizes a version of the streamlined methodology that was also tested in California.[114] The utilities proposed using a four-tiered approach for the analysis, each step in the process is intended to add greater detail and granularity as utility data sets and modeling tools evolve.[115] The four steps identified were to develop: 1) distribution indicators, 2) hosting capacity evaluations, 3) advanced hosting capacity evaluations, and 4) fully integrated DER value assessments.[116] The first step involves each utility publishing a map with basic information about circuits (i.e. voltage of the line, already connected generation, etc.); these maps do not include any data analysis of the circuits. The second step entails the first iteration of the HCA, where the utilities will publish ranges of potentially available capacity. The HCA at this stage is only evaluating the hosting capacity for large-scale solar and not providing information on the capacity for small solar or other types of DER (e.g. electric vehicles or energy storage). In addition, the hosting capacity model does not include in the analysis DERs that are already connected to the grid.[117] Less detail is available on exactly what will be included in the third iteration, but it may include analysis down to the nodal level and further modeling of "operational flexibility" constraints.

Despite widespread dissatisfaction with the approach laid out by the utilities,[118] the Commission's Order largely approved the utilities' plans, however it required that they move ahead on a faster timeline, requiring that the stage 2 analysis be completed for all 12 kV circuits and above by October 1, 2017.[119] The NY PSC also required that basic information about the feeder be published in the maps, that the presentation of the data be more consistent across the utilities, and that some data be available to download.[120] The NY PSC approved the utilities plan to only update the analysis on an annual basis, with monthly updates of the interconnection queue data.

Figure 14. Joint Utilities of New York Hosting Capacity Road Map

Source: *New York Joint Utilities, Case 16-M-0411, Supplemental Distributed System Implementation Plan, p. 48 (Nov. 1, 2016)*



While the process underway in New York is certainly likely to produce considerably more information than has ever been available to third parties about the state of the distribution system in New York, it is unclear how valuable the results will be to guiding decision making, either in the regulatory context or for specific investment decisions by third parties. The NY PSC has thus far declined to identify specific use cases for the analysis and made no specific plans for ultimately being able to utilize this information in processing interconnection applications or in the distribution planning process. There also has not been any demonstration of the accuracy of the results of the methodology which will need to be done if the tool is to be used for decision-making purposes going forward.

Lessons learned from the New York process:

- The four-tiered approach in New York provides an illustration of how a state may approach the rollout of an HCA in a manner that will provide more detailed information over time as data and methodology improves.

- The New York experience illustrates some of the challenge of not identifying clear uses cases prior to commencing selection and development of the technical methodology for the HCA. Since there was no identification of desired uses, it is not clear exactly how the information coming out of the HCA produced will be used to guide or inform decision making.

- States should strive to ensure greater public transparency and vetting of the chosen methodology through the regulatory process. Thorough vetting of the methodology through publicly available studies, test runs, or comparative tests can demonstrate the accuracy of the tool and the relative consistency in its application across utility territories. Conducting this process publicly can utilize the collective knowledge of a wider range of stakeholders and also ensure broader support and confidence in the outcomes of the HCA.

- Commencing stakeholder engagement prior to utilities having made major decisions about methodology and approach increases the likelihood that utilities will not be path dependent by the time they reach out to stakeholders and will also help to ensure that the tool is designed to serve customers' needs. In addition, the stakeholder engagement process should be structured to ensure that stakeholder feedback is objectively recorded and reported on the record for review by regulators regardless of whether input is ultimately taken by the utilities.

- Including one segment of one type of DER (large scale PV) in the initial methodology may be an appropriate interim step from a resource standpoint, but it places severe limits on the usefulness of the information for expanding hosting capacity and allowing DERs to be used to address constraints on the system.

MINNESOTA CASE STUDY

HCA in Minnesota arose out of a 2015 statutory directive requiring Xcel Energy to file information regarding the interconnection of small-scale distributed generation (DG) projects within the biennial transmission planning process.[121] As part of this process, the Minnesota Public Utility Commission (MN PUC) required Xcel to complete an analysis of the hosting capacity of each feeder on Xcel's distribution system for DG of 1 MW or less and to identify potential distribution system upgrades necessary to support expected DG growth.[122]

On December 1, 2016 Xcel filed a distribution system study containing its initial HCA results.[123] As did the New York Joint Utilities, Xcel elected to use EPRI's proprietary DRIVE tool to assess the hosting capacity of individual feeders through a streamlined hosting capacity method. The DRIVE tool provided Xcel with a choice of three DER deployment scenarios to allocate DER across a feeder: large centralized, large distributed, and small distributed. Of the three, Xcel selected the small distributed generation scenario, which it deemed consistent with the PUC order's focus on small DG resources. Xcel ran the analysis on more than 1,000 feeders in its distribution system.[124] Owing to limitations in the DRIVE tool, Xcel did not include in its analysis existing or forecasted DERs, and it did not apply mitigations to determine if hosting capacity could be increased.[125] Xcel published its results in a summary chart that reported for each feeder the minimum and maximum hosting, the limiting violation, and the currently installed and proposed DG.[126] The initial report did not include a map showing the hosting capacity or any downloadable data in a sortable form.

The MN PUC initiated a new round of commenting on Xcel's hosting capacity study. The PUC issued an information request to Xcel requiring that the utility issue responses to a list of questions intended to clarify Xcel's hosting capacity model and to assist stakeholders in providing comments.[127] And it invited public comments on Xcel's hosting capacity report and its supplemental comments in response to the MN PUC's information request.[128] The MN PUC then held a public meeting at which stakeholders were given an opportunity to present their positions on Xcel's filings and the proposed MN PUC action.[129]

After considering stakeholder written and oral comments, the MN PUC issued an order on August 1, 2017 in which it set forth guidance for subsequent hosting capacity reports by Xcel.[130] The order required Xcel to file hosting capacity reports on an annual basis with sufficient detail to provide customers "with a starting point for interconnection applications" and "to inform future distribution system planning efforts and upgrades necessary to facilitate the continued efficient integration of [DG]."[131] The PUC directed Xcel to display the annual hosting capacity results in a color-coded map representing the available hosting capacity of Xcel's distribution grid down to the feeder-level and to provide downloadable hosting capacity results in spreadsheet format.[132] The PUC also directed Xcel to include in its November 1, 2017 report information requested by staff and parties through comments on its 2016 report and information on the accuracy of its hosting capacity results, including by conducting a comparison of results in its 2016 report with actual hosting capacity determined through interconnection studies.[133]

Xcel filed this updated HCA and supporting information requested by the MN PUC on November 1, 2017.[134] The New HCA includes some additional improvements and refinements, including the incorporation of existing known DERs, a change from modeling small DERs to instead using the "large centralized" DER option in DRIVE, and inclusion of some changes to allow for limited modeling of certain smart inverter and voltage regulation devices.[135] The results are now also published on a publicly available map.

In parallel, the MN PUC has begun considering HCA as part of its broader Grid Modernization proceeding, initiated in 2015. The PUC issued a distribution system planning questionnaire in which, among other things, it directed Minnesota's three investor owned utilities—Xcel, Minnesota Power, and Otter Tail Power Company—to report on any HCA they currently conduct, and invited cooperative and municipal utilities to do the same.[136] And it solicited comments from all stakeholders on the form that analysis should take.[137] The MN PUC has not yet clarified to what extent hosting capacity will be part of this broader proceeding and how it will relate to the separate Xcel proceeding.

The Minnesota proceedings are a unique case study in several respects: they have thus far utilized a predominantly written commenting process for stakeholder engagement with respect to hosting capacity; they represent one approach to tailoring hosting capacity requirements to utilities of very different sizes and types of service areas; and they have created parallel tracks within which HCA can be addressed.

Lessons learned from Minnesota include:

- The Minnesota experience highlights strategies for meaningfully incorporating stakeholder input through written comments. At each stage of Xcel's hosting capacity proceeding, the MN PUC solicited written comments from stakeholders, and it transparently considered and incorporated feedback into its recommendations and directives. The MN PUC demonstrated its consideration of stakeholder positions by summarizing comments in its orders and by directing the utilities to answer specific questions about their methodologies. Outcomes reflect the MN PUC's consideration of stakeholder input. For instance, the MN PUC's order on Xcel's hosting capacity report directed Xcel to address stakeholder concerns with the accuracy of its hosting capacity methodology.[138] Xcel responded with additional information on the methodology[139] and the Commission has invited stakeholder comments on Xcel's response.[140]

- The Minnesota experience suggests that solicitation of written comment can be particularly effective for considering stakeholder feedback on technical components of HCA. But it may have limitations when used as the only method to engage stakeholders in the broader policy dimensions of hosting capacity. In response to the MN PUC's questionnaire in its distribution study proceeding, a number of stakeholder groups recommended that the MN PUC couple written comments with working groups or workshops, particularly for developing hosting capacity goals and use cases.[141]

- Xcel is by far the largest utility in Minnesota but others—Minnesota's two smaller investor owned utilities and its municipal and cooperative utilities—are important players. The MN PUC has accounted for these distinctions by, consistent with the statutory directive, requiring Xcel to be the first mover in developing HCA while engaging all utilities in the exploration of hosting capacity in its distribution system planning proceeding. This latter proceeding represents a valuable potential opportunity to formulate hosting capacity goals and use cases applicable to all utilities as well as timelines tailored to the respective utilities' systems and needs.

- The Xcel hosting capacity proceeding, similar to the experiences in California and New York, illustrates the drawbacks of mandating HCA before establishing goals and use case. Significant concerns have been raised with the accuracy of Xcel's methodology and the usefulness of its results, and it remains to be seen whether the DRIVE tool can be tailored to meet the needs of the use cases ultimately selected. Significant costs and delays could be avoided by beginning with the broader policy discussion.

- Xcel's method initially focused on small DG and its most recent version focuses on large DG, although neither scenario is a likely representation of expected DG growth (which will likely include a mix of both small and large DERs). The initial version of its hosting capacity did not incorporate installed and pending DER, but the most recent version now includes installed DERs.[142] There have been a number of other improvements between the first and second iteration. However, stakeholder concerns regarding the lack of transparency of the DRIVE tool, which hinders their ability to provide effective feedback on its capabilities and limitations, persists.[143]

- The MN PUC has thus far considered hosting capacity as a guide for interconnection filings rather than a method that could eventually automate—or nearly automate—the interconnection process. This way of thinking may limit the state's broader grid modernization efforts or result in substantial costs if utilities are required to reinvent their hosting capacity methods when the interconnection use case changes.

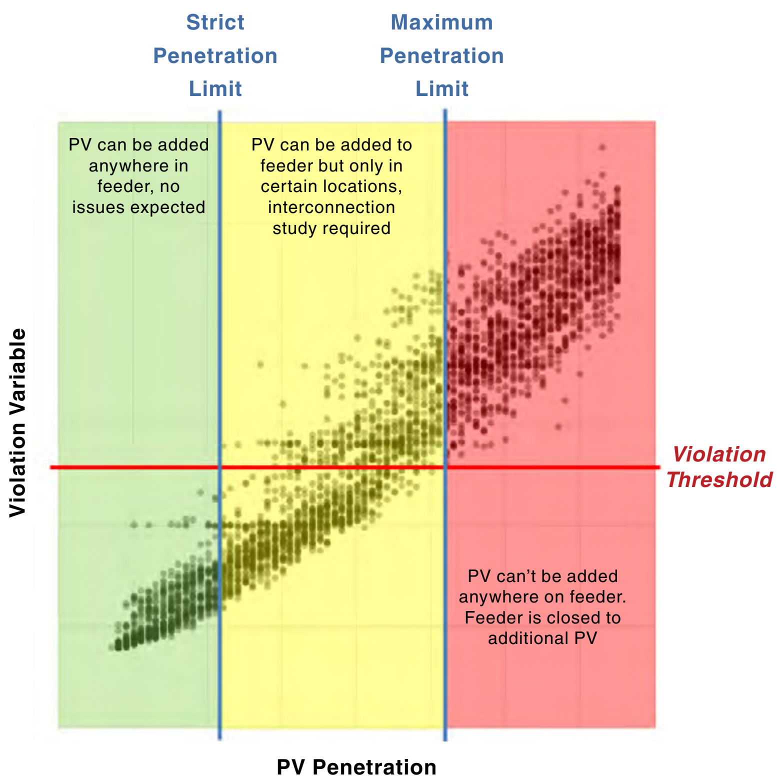
PEPCO CASE STUDY

Pepco Holdings, Inc. was one of the first utilities to deploy a hosting capacity model across their service territory which covers parts of New Jersey, Maryland, Washington D.C., and Delaware. Coming out of a study funded by the DOE in 2015, Pepco's model utilizes what is known as the "stochastic method" to determine the hosting capacity of its feeders.[144] Rather than identifying a specific hosting capacity amount for a feeder, the method runs various scenarios with solar PV randomly placed on a feeder to determine a range of possible hosting capacity figures. The chart below provides a visualization of the results of this method.[145] The green area on the left shows the scenarios that were run where no violations of hosting capacity limits would occur regardless of PV location, the yellow area shows scenarios where potential PV could be located without violations, but only in certain locations (thus a study might be required), and the area in red shows scenarios where there would be an absolute violation of the circuit limits regardless of location.

Pepco has begun to use the results of this analysis to help streamline the interconnection process in their territory. Using their HCA Pepco identifies "restricted circuits" on their system, which are circuits where "a major distribution infrastructure investment would be required to allow the DER to interconnect without creating a violation of utility system

Figure 15. Pepco Definition of Strict and Maximum PV Penetration Limits

Source: *Pepco Holdings, Inc., Model-Based Integrated High Penetration Renewables Planning Control and Analysis, p. 11 (Dec. 14, 2015)*



operational parameters."[146] There are three categories of restricted circuits: (1) those that are restricted to all sizes, (2) those that are restricted to systems below 250 kW, and (3) those that are restricted to systems below 50 kW.[147] Pepco publishes their hosting capacity map (or "restricted circuit map") on their website (updated at least quarterly) which color codes circuits based upon their restriction category.[148] Pepco is able to streamline the interconnection process for projects not located on a restricted circuit, or for those sized below the circuit restriction level, as long as they also meet a set of "criteria limits" the utility has defined.[149] While this approach has value in reducing the amount of individualized review that projects receive in the interconnection process, it may also underestimate hosting capacity for certain projects and provides a less precise result to guide the design of projects seeking to maximize hosting capacity. As part of the DOE project, Pepco has also identified mitigation strategies for increasing hosting capacity on a circuit.[150]

Pepco initiated this process absent any formal regulatory requirement as a way to help better manage their distribution system and the interconnections to that system. While this proactive approach by the utility can lead to some immediate and positive outcomes for customers, there are potential drawbacks to proceeding with a significant HCA rollout without the benefit of a robust stakeholder process. The HCA methodology used and the limits and assumptions built into that methodology have not undergone any public vetting for fairness or accuracy. Since the HCA is being used to facilitate, but also restrict, interconnection access it is important that regulators ensure that methods used are reasonable and valid.

Appendix B: References

Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project (June 2013)

IREC, *Integrated Distribution Concept Paper: A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources* (May 2013)

IREC, *Easing the Transition to a More Distributed Electricity System* (Feb. 2015)

EPRI, *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State* (June 2016)

EPRI, *Alternatives to the 15% Rule* (Dec. 2015)

EPRI, *Integration of Hosting Capacity Analysis into Distribution Planning Tools* (Jan. 2016)

EPRI, *Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV* (Dec. 2012)

Solar Energy Industries Association, *Hosting Capacity: Using Increased Transparency of Grid Constraints to Accelerate Interconnection Processes* (Sept. 2017)

Solar City, *Integrated Distribution Planning: A Holistic Approach to Meeting Grid Needs and Expanding Customer Choice by Unlocking the Benefits of Distributed Energy Resources* (Sept. 2015)

ICF International, *Integration Distribution Planning*, Prepared for MN PUC (Aug. 2016)

Regulatory Assistance Project, *Electricity Regulation in the United States: A Guide* (2d ed. June 2016)

Endnotes

1 The term Distributed Energy Resources, or DERs, refers to resources located on the distribution system (in front of or behind the customer meter). These resources may vary by jurisdiction. For purposes of this paper, the term includes distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. The impact on hosting capacity varies significantly between DER technologies depending upon whether the technology is a new load source (e.g. electric vehicles), a load shift or reduction (e.g. demand response), a generating resource (e.g. solar PV) or some combination of these (e.g. energy storage).

2 A node is a point on a feeder between two line sections. Circuit characteristics may be analyzed at each selected node along the circuit.

3 Tim Lindl, et al., *Integrated Distribution Planning Concept Paper: A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources*, IREC and Sandia National Laboratories (May 2013) ("IDP Concept Paper"), http://www.irecusa.org/publications/integrated-distribution-planning-concept-paper/.

4 For examples of state grid modernization proceedings that integrated IDP, see Cal. Public Utilities Commission, Distribution Resources Plan Dkt., R. 14-08-013; NY Public Service Commission, Reforming the Energy Vision Dkt., Case 14-M-0101; and MN Public Utilities Commission, Staff Report on Grid Modernization, pp. 15-16 (Mar. 2016) (identifying integrated distribution planning as the first of nine key steps to explore in Minnesota's grid modernization efforts).

5 As used throughout this paper, the term "use case" refers to the primary function and/or application of the hosting capacity analysis. Refer to Section II.B for additional information.

6 Appendix B to this report provides a compilation of recent resources on hosting capacity and related distribution planning and interconnection topics.

7 *See* Electric Power Research Institute ("EPRI"), *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State*, p.3 (June 2016) ("Defining a Roadmap") (defining "hosting capacity"); *see also* Cal. Public Utility Commission, R. 14-08-013, Assigned Commissioner's Ruling Re. Draft Guidance for Use in Utility AB 327 (2013) Section 769 Distribution Resource Plans, Attachment pp. 15-16 (Nov. 17, 2014) (introducing Integrated Capacity Analysis ("ICA") as a tool for determining distribution system hosting capacity).

8 *See, e.g.*, Defining a Roadmap at p. 10 (summarizing these four power system criteria); San Diego Gas & Electric Company, R. 14-08-013, Demonstration Projects A & B Final Reports of San Diego Gas & Electric Company (U 902-E), Demonstration A—Enhanced Integration Capacity Analysis, p. 30 (Dec. 22, 2016) ("SDG&E Final Report A") (explaining that the Assigned Commissioner's Ruling required the three California investor owned utilities to examine these "four major categories of power system criteria . . . to determine the DER integration capacity for the nodes and line sections on each distribution feeder"); *id.* at pp. 34-39 (describing the four criteria and their role in hosting capacity analysis).

9 Solar City, *Integrated Distribution Planning: A Holistic Approach to Meeting Grid Needs and Expanding Customer Choice by Unlocking the Benefits of Distributed Energy Resources*, p. 5 (Sept. 2015) ("Solar City IDP") (HCA "provide[s] an indication of how many DERs can be accommodated given existing utility and customer-owned equipment on a circuit").

10 EPRI, *Alternatives to the 15% Rule: Final Project Summary*, p. xii (Dec. 2015) ("Minimum hosting capacity is defined as the lowest amount of PV that causes the first violation on a feeder.").

11 EPRI, *Integration of Hosting Capacity Analysis into Distribution Planning Tools*, pp. 3-4 (Jan. 2016) ("EPRI Integration").

12 *Id.* at p. 3.

13 The hosting capacity of a feeder can also vary depending on the type of scenario selected—such as centralized versus highly distributed DERs and whether backfeed through the substation is permitted. *See* Defining a Roadmap at pp. 11-12.

14 Smith, Jeff and Matthew Rylander, PhD, *Overview of Hosting Capacity Methods: Detailed and Streamlined Methods*, Electric Power Research Institute, presented to the California Integration Capacity Analysis Workgroup, slides 9-10 (June 9, 2016), http://drpwg.org/wp-content/uploads/2016/06/EPRI_Hosting-Capacity-Methods_Smith.pdf.

15 *Id.* at p. 8; see also Pacific Gas & Electric Co., R. 14-08-013, Pacific Gas & Electric Company's (U 39 E) Demonstration Projects A & B Final Reports, Appendix A (Demonstration Project A—Enhanced Integration Capacity Analysis), pp. 146-55 (Dec. 27, 2016) ("PG&E Final Report A")

(describing metrics set out by the California PUC for utilities to meet in developing and testing ICA methods).

16 See Solar City IDP at p. 2; Erica McConnell & Cathy Malina, *Interconnection: The Key to Realizing Your Distributed Energy Policy Dream*, Greentech Media (Oct. 25, 2016), https://www.greentechmedia.com/articles/read/interconnection-the-key-to-realizing-your-distributed-energy-policy-dream#gs.ppLHx9k.

17 K. Ardani, et al., *A State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States*, National Renewable Energy Laboratory, p. 13 (Jan. 2015).

18 See NC Utilities Comm., Dkt. E-100, Sub 101A, Duke Energy Carolinas, LLC, Quarterly Interconnection Queue Performance Report (Oct. 20, 2017) (over 61% of projects take between 360 to over 990 days from entering queue to receiving interconnection agreement).

19 For a more thorough discussion of the benefits of data sharing in the interconnection process, see Erica McConnell & Cathy Malina, *Knowledge is Power: Access to Grid Data Improves the Interconnection Experience for All*, Greentech Media (Jan. 31, 2017), https://www.greentechmedia.com/articles/read/knowledge-is-power-access-to-grid-data-and-improves-the-interconnection-exp#gs.SVY9Tdw.

20 For more information on the background of interconnection screening see Kevin Fox, Sky Stanfield, et. al., *Updating Small Generator Interconnection Procedures for New Market Conditions*, National Renewable Energy Laboratories, p. 2-10 (Dec. 2012).

21 See EPRI, *Alternatives to the 15% Rule: Final Project Summary*, p. vii (Dec. 2015)

22 *See Integrated Distribution Planning: Prepared for Minnesota Public Utilities Commission*, ICF International, p. vi. (Aug. 2016) ("ICF IDP") ("There is a recognition nationally by utilities, stakeholders, and regulators that improvements to processing and studying interconnection requests are needed to meet customers' expectations and manage work flow."); PG&E Final Report at p. 156 (reporting that the iterative method "could help streamline Fast Track studies and improve the outdated methods such as the 15% rule in screen M"); Hawaiian Electric Companies, Initial Statement of Position on Deferred Issues and Technical Track. Issues, , Exhibit C, Circuit Hosting Capacity Analysis: Benefits and Future Improvements, p. 1 (Aug. 2017) ("The use of circuit hosting capacity by the Hawaiian Electric Companies . . .has resulted in additional interconnection approvals." and "Circuit hosting capacity facilitates faster interconnections.").

23 *See* Cal. Public Utilities Commission, R. 14-08-013, Protest of the Interstate Renewable Energy Council, Inc. to Applications of San Diego Gas & Electric Company, Pacific Gas & Electric Company, and Southern California Edison Company for Approval of their Distribution Resources Plans, p. 23 (Aug. 31, 2015) ("IREC Protest of DRP Applications").

24 *See id*. at p. 22.

25 Pre-application reports provide readily available information about a particular point of interconnection on a utility's system. The information generally provided includes items such as the circuit and substation voltage, the amount of already connected and queued generation, the distance of the proposed point of interconnection to the substation, and peak and minimum load data. These reports are available in a handful of states where they help guide customers. But they have limitations: they do not contain any actual system analysis and can take over a month to receive. See Erica McConnell & Cathy Malina, *Knowledge is Power: Access to Grid Data Improves the Interconnection Experience for All*, Greentech Media (Jan. 31, 2017), https://www.greentechmedia.com/articles/read/knowledge-is-power-access-to-grid-data-and-improves-the-interconnection-exp#gs.SVY9Tdw; Zachary Peterson, The State of Pre-Application Reports, National Renewable Energy Laboratories (June 2017), https://www.nrel.gov/dgic/interconnection-insights-2017-07.html.

26 *See, e.g*. Quarterly Interconnection Reports for the California Investor Owned Utilities, http://www.cpuc.ca.gov/General.aspx?id=4117 (these reports show the number of pre-application reports that have been requested in recent years; although, given their relative newness, efforts to collect more comprehensive data to measure their full impact on interconnection applications are still underway).

27 Cal. Public Utilities Commission, R. 14-08-013, Assigned Commissioner's Ruling on Guidance For Public Utilities Code Section 769—Distribution Resource Planning, Attachment (Guidance for Section 769—Distribution Resource Planning), p. 3 (Feb. 6, 2015) ("Final CPUC Guidance").

28 *Id*.

29 Cal. Public Utilities Commission, R. 14-08-013, Assigned Commissioner's Ruling (1) Refining

Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B (May 2, 2016); *see also* Cal. Public Utilities Commission, R. 14-08-013, Email Ruling of Administrative Law Judge Mason (June 10, 2016) (authorizing the utilities to conduct a comparison of both methodologies in their demonstration projects).

30 Cal. Public Utilities Commission, R. 14-08-013, Integration Capacity Analysis Working Group Final Report, pp. 7-14 (Mar. 15, 2017).

31 Cal. Public Utilities Commission, R. 14-08-013, Decision 17-09-026, Decision on Track 1 Demonstration Projects A (Integration Capacity Analysis) and B (Locational Net Benefits Analysis), pp. 29-33 (Sept. 28, 2017) ("CPUC Decision on Track 1 Demonstration Projects").

32 Hawaiian Electric Companies, Initial Statement of Position on Deferred Issues and Technical Track. Issues, Exhibit C, Circuit Hosting Capacity Analysis: Benefits and Future Improvements, p. 5 (Aug. 14, 2017) (HECO's "analysis is closer to that of an iterative methodology, where simulations are run until a hosting capacity number (with no criteria violations) is determined, which the [California] IOUs concluded yields higher hosting capacity values and more accurate results.").

33 *Id*. at p. 4 ("The [Hawaiian Electric] Companies have three use cases for the circuit hosting capacity analysis, applying it as a tool to (1) streamline the interconnection process for customers, (2) inform customers and DER developers where saturated circuits are located, and (3) inform the planning process and identify circuit constraints to be solved to expand DER growth.")

34 NY Public Service Commission, Dkt. 16-M-0411, In the Matter of Distributed System Implementation Plans; NY Public Service Commission, Dkt. 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

35 The Joint Utilities include: Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation, all investor owned utilities.

36 New York Joint Utilities, Case 16-M-0411, Supplemental Distributed System Implementation Plan, p. 49 (Nov. 1, 2016) ("SDSIP").

37 NY Public Service Commission, Case 16-M-0411, Order on Distributed System Implementation Plan Filings, pp. 10-15 (Mar. 9, 2017).

38 MN Public Utilities Commission, Dkt. E002/M-14-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report, p. 5 (Aug. 1, 2017).

39 Minn. Stat. § 216B.2425, subd. 8.

40 Xcel Energy, Dkt. E002/M-15-962, Distribution System Study: Distribution Grid Modernization Report, p. 13 (Dec. 1, 2016) ("Xcel Distribution System Study") (noting that the initial hosting capacity results are "not intended to be used for approving interconnection requests at this time").

41 MN Public Utilities Commission, Dkt. E002/M-14-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report, p. 5 (Aug. 1, 2017).

42 *Id*.

43 Xcel Energy, Dkt. E002/M-17-777, Distribution System/Hosting Capacity Study, p. 17-20 (Nov. 1, 2017).

44 *See* Herman K. Trabish, *How Utility Data Sharing is Helping the New York REV Build the Grid of the Future*, Utility Dive (Feb. 8, 2017), http://www.utilitydive.com/news/how-utility-data-sharing-is-helping-the-new-york-rev-build-the-grid-of-the/434972/ ("Currently, only utilities have full access to the data needed to fully understand the [distribution] system's limits and potential, and even they often lack visibility to understand exactly where all their assets are located.").

45 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy Economy (Aug. 11, 2015), http://blog.aee.net/understanding-irps-how-utilities-plan-for-the-future ("Historically, utilities mainly considered generation, transmission, and distribution additions to meet growing demand.").

46 *See* Krysti Shallenberger, *The Top 5 States for Utility Grid Modernization and Business Model Reform* (Apr. 3, 2017), http://www.utilitydive.com/news/the-top-5-states-for-utility-grid-modernization-and-business-model-reform/439550/ (discussing grid modernization activities in California, New York, Minnesota, Massachusetts, and Rhode Island, as well as developments in other states).

47 *See, e.g.*, NY Public Service Commission, Case 14-M-0101, Order Adopting Distributed System Implementation Plan Guidance, p. 2 (Apr. 20, 2016) ("At the core of the new model is improved information—improved both in its granularity, temporal and spatial, and in its accessibility to consumers and market participants."); Cal. Public Utilities Commission, R.14-08-013, Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769—Distribution Resource Planning, p. 5 (Feb. 6, 2015) ("Each iteration of the process will move California further down a path toward deeper penetration of DER, more effective analysis of where DER provides the most value to customers and to the electric distribution system, and a greater understanding of the policy framework that is necessary to achieve these goals.").

48 IDP Concept Paper at p. 10.

49 *See* SDSIP at pp. 28-29 (discussing role of HCA in competitive solicitation of non-wires alternatives).

50 Hawaiian Electric Companies, Initial Statement of Position on Deferred Issues and Technical Track. Issues, Exhibit C, Circuit Hosting Capacity Analysis: Benefits and Future Improvements, p. 4 (Aug. 2017) ("Finally, the hosting capacity analysis helps distribution planners to identify congested circuits and find solutions to integrate high forecasted levels of DER. Once current and near-term circuit constraints are identified, planners can find potential solutions for solving those constraints — whether the solution is a low-cost utility-side adjustment, a customer solution (i.e., advanced inverter), or a traditional circuit upgrade.").

51 *Id*.; Solar City IDP at pp. 7-8

52 ICF IDP at p. 4.

53 *See id*. at p. 9 ("A better approach [than using singular deterministic forecasts] is to use multiple DER growth scenarios to assess current system capabilities, identify incremental infrastructure requirements and enable analysis of the locational value of DERs.")

54 *See*, More Than Smart, *Integration Capacity Analysis Working Group - Group I Interim Status Report*, p. 2 (Aug. 31, 2017), http://drpwg.org/wp-content/uploads/2016/07/ICA-Group-I-interim-status-report-final.pdf

55 See SDSIP at p. 55 ("An evolution to this more detailed hosting capacity analysis [in Stage 3] will enable planners to more specifically identify locations along a feeder with higher levels of hosting capacity and determine how sub-feeder-level hosting capacity is impacted by current and prospective DER interconnections on the system.").

56 Cal. Public Utilities Commission, R. 14-08-013, Integration Capacity Analysis Working Group Final Report, p. 9 ("The WG determined that there is a role for a planning use case for the ICA, as it may be possible that the ICA can help determine and guide where and when future integration capacity is a limitation, among other possible planning uses. . . However, many components of this use case remain undefined, due to multiple ongoing efforts in other CPUC proceedings that will inform how ICA will be used in system planning, as well as the need for further clarity into the utility annual planning process itself.").

57 Southern California Edison, R. 14-08-013, Southern California Edison Company's (U338-E) Update Demonstration Projects A and B Final Reports, Appendix B (Locational Net Benefit Analysis Final Report), p. 2 (Jan. 4, 2017) ("SCE Final Report B").

58 *Id*.; ICF IDP at p. 16.

59 ICF IDP at p. 16

60 *Id*. ("[T]he value of DER on the distribution system is locational in nature—that is, the value may be associated with a distribution substation, an individual feeder, a section of a feeder, or a combination of these components.").

61 *Id*. ("The cost estimates of [planned infrastructure] investments form the potential value that may be met by sourcing services from qualified DERs as non-wires alternatives.").

62 *Id*.

63 Bebon, Joseph, *Solar Groups Speak Out Against Recent NY Ruling*, Solar Industry Magazine (Sept. 18, 2017), https://solarindustrymag.com/solar-groups-speak-latest-n-y-ruling.

64 Cal. Public Utilities Commission, R.14-08-013, Assigned Commissioner's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff White Paper on Grid Modernization, Attachment (Staff White Paper on Grid Modernization), pp. 20, 22 (May 16, 2017) ("Grid Modernization White Paper") (setting forth development of LBNA, as well as a Grids Needs Assessment based on LNBA and ICA results, in Staff's proposed Grid Modernization process for California investor owned utilities); see also LNBA Working Group reports, California's Distribution Resources Plan, R. 14-08-013, http://drpwg.org/sample-page/drp/.

65 Cal. Public Utilities Commission, R.14-08-013, Administrative Law Judge's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework, Attachment A (Energy Division Staff Proposal on a Distribution Investment Deferral Framework), pp. 11-13 (June 30, 2017) ("Distribution Investment Deferral Framework").

66 *Id*. at pp. 29-30.

67 Grid Modernization White Paper at pp. 23-24.

68 NY Public Service Commission, Case 15-E-0751, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters, p. 5 (Sept. 14, 2017).

69 SDG&E Final Report A at p. 31.

70 *Id*. at pp. 19, 33, 49.

71 *See* Pepco Holdings, Inc., *Model-Based Integrated High Penetration Renewables Planning Control and Analysis*, pp. 7-8 (Dec. 14, 2015); EPRI, *Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV* (Dec. 2012).

72 *See* Xcel Distribution System Study at pp. 3-4; SDSIP at p. 52.

73 *See*, e.g. EPRI Integration at 7.

74 SDSIP at p. 49.

75 SDSIP at p. 52; Xcel Distribution System Study at p. 11.

76 PG&E Final Report A at p. 16.

77 *Id*. at p. 17.

78 *See* NY Public Service Commission, Case 16-M-0411, Order on Distributed System Implementation Plan Filings, pp. 10-15 (Mar. 9, 2017); Xcel Distribution System Study at pp. 3-4, 6 (focusing HCA analysis on small-scale distributed generation technologies); Xcel Energy, Dkt. E002/M-15-962, Supplemental Comments: Biennial Distribution Grid Modernization Report, pp. 9, 11 (Mar. 20, 2017) (explaining that "energy storage load characteristics were excluded from [Xcel's HCA] analysis" and excluding demand response and energy efficiency technologies from Xcel's definition of DER); Pepco Analysis (discussing only PV penetration).

79 See Xcel Distribution System Study at pp. 10-12; SDG&E Final Report A at p. 39 (regarding use of a heuristic approach to evaluate the operational flexibility criterion); Pacific Gas & Electric Co., R. 14-08-013, Demonstration A—Enhanced Integration Capacity Analysis: PG&E ICA Demo A Interim Report, p. 7 (Sept. 30, 2015) ("In order to ensure transparency and consistency within the methodology, the various assumptions and starting point parameters must be expressed" so that, for instance, results can be replicated by third parties.).

80 SDG&E Final Report A at p. 79.

81 PG&E Final Report A at p. 116.

82 See EPRI Integration at p. 7.

83 PG&E's PV RAM maps, for instance, "employ a coloring scheme that depicts the capacity level of a line section by a color gradient to better display the varying levels of capacity by location on each feeder. This coloring scheme is intended to help DER developers and customers better understand where on a circuit location of a DER is better suited." PG&E Final Report at p. 118. PG&E's RAM maps are available at 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; Central Hudson's Hosting Capacity Map is available at https://www.cenhud.com/dg/dg_hostingcapacity ("Each distribution circuit is color coded based on its maximum hosting capacity value."); Pepco Holding LLC's Hosting Capacity Map is available at http://www.pepco.com/Hosting-Capacity-Map.aspx.

84 *See RESTful API*, SearchCloudStorage.com, http://searchcloudstorage.techtarget.com/definition/RESTful-API ("A RESTful API is an application program interface (API) that uses HTTP requests to GET, PUT, POST and DELETE data.").

85 Cal. Public Utilities Commission, R. 14-08-013, Integration Capacity Analysis Working Group Final Report, p. 5 (Mar. 15, 2017).

86 Interstate Renewable Energy Council, Case 16-M-0411, Comments of the Interstate Renewable Energy Council, Inc. on the Supplemental Distributed System Implementation Plan, p. 11 (Jan. 9, 2017).

87 *Id*.

88 Cal. Public Utilities Commission, R. 14-08-013, Decision on Track 1 Demonstration Projects, pp. 58-61 (Oct, 6, 2017).

89 Cal. Public Utilities Code § 769; *see also* Cal. Assembly Bill 327 (Perea 2013).

90 Cal. Public Utilities Commission, R. 14-08-013, Assigned Commissioner's Ruling on Guidance For Public Utilities Code Section 769—Distribution Resource Planning, Attachment, at pp. 3-4 (Feb. 6, 2015).

91 *Id*.

92 *Id*. at p. 4 (Ordering the utilities to: "Specify recommendations for utilizing the Integration Capacity Analysis to support planning and streamlining of Rule 21 for distributed generation and Rule 15 and Rule 16 assessments of EV load grid impacts, with a particular focus on developing new or improved 'Fast Track' standards.").

93 *See* California ICA Working Group materials, California's Distribution Resources Plan, R. 14-08-013, http://drpwg.org/sample-page/drp/ and http://drpwg.org/archive-ica-and-lnba-working-group/.

94 See Joint Motion of San Diego Gas & Electric Company (U 902 E), Southern California Edison Company (U 338 E), and Pacific Gas and Electric Company (U 39 E), R.14-08-013 (June 9, 2016) (seeking permission to perform a test of both methodologies as part of the demonstration project); Cal. Public Utilities Commission, R. 14-08-013, Email Ruling of Administrative Law Judge Mason (June 10, 2016) (authorizing the utilities to do a comparison of both methodologies in their Demonstration projects).

95 Cal. Public Utilities Commission, R. 14-08-013, Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B (May 2, 2016).

96 PG&E Final Report A at p. 53.

97 PG&E Final Report A at p. 98 ("In general, the streamlined approach focused on speed and abstraction of analysis across components while the iterative is focused on detail and precision of power flow results closer to what may be seen in an interconnection study.").

98 SDG&E Final Report A at p. 45.

99 Southern California Edison, R. 14-08-013, Southern California Edison Company's (U 338-E) Update Demonstration Projects A and B Final Reports, Appendix A (Enhanced Integration Capacity Analysis Final Report), p. 80 (Jan. 4, 2017) ("SCE Final Report A"); PG&E Final Report A at p. 105.

100 SCE Final Report A at pp. 45, 47.

101 PG&E Final Report A at pp. 96, 143.

102 PG&E Final Report A at p. 11 ("The streamlined techniques are better suited to more appropriately analyze large amounts of scenarios for planning purpose, while the iterative is better suited for analyzing circuit conditions for specific interconnection purposes"); SDG&E Final Report A at p. 9; SCE Final Report A at pp. 2-3.

103 SDG&E Final Report A at p. 9; PG&E Final Report A at 155.

104 PG&E found that the iterative methodology was better suited for interconnection, while streamlined was better suited for planning purposes. PG&E proposed using the streamlined method for the mapping and then recommended the iterative results be applied when actually processing interconnection applications for software efficiency reasons. The ICA working group found this approach unworkable because it wanted ICA maps to accurately reflect the results an applicant could expect from the interconnection process. Cal. Public Utilities Commission, R. 14-08-013, Integration Capacity Analysis Working Group Final Report, pp. 12-14 (Mar. 15, 2017).

105 Cal. Public Utilities Commission, R.14-08-013, Decision on Track 1 Demonstration Projects, pp. 29-33.

106 For information on the ongoing ICA Working Group discussions regarding the planning use case see http://drpwg.org/sample-page/drp/.

107 For more about Reforming the Energy Vision, visit http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument.

108 NY Public Services Commission, Case 14-M-0101, Order Adopting Distributed System Implementation Plan Guidance, pp. 43-46 (Apr. 20, 2016).

109 *Id*. at pp. 19-22.

110 The Joint Utilities are comprised of Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation.

111 EPRI, Defining a Roadmap.

112 *Id*. at p. 4.

113 SDSIP at p. 52; see also EPRI Integration.

114 To date there has been no published analysis that compares exactly how the "streamlined" method tested in California compares with the current version of the DRIVE tool. However, PG&E stated in their distributed resources plan that it's "approach is similar to the Electric Power and Research Institute (EPRI) streamlined hosting capacity for PV Interconnection." Pacific Gas and Electric Co., R. 14-08-013, *Electric Distribution Resources Plan*, p. 23 (July 1, 2015). EPRI has yet to publish any public information that details the methodology used to support the DRIVE tool (though this information may be available to paying members) nor has there been an objective analysis done that analyzes the accuracy of the results produced by the DRIVE tool.

115 SDSIP at p. 48.

116 *Id*. at 49.

117 NY Public Service Commission, Cases 14-M-0101, 16-M-0411, Order on Distributed System Implementation Plan Filings, p. 11 (Mar. 9, 2017) ("Hosting capacity ranges are based on the circuit characteristics and assume that there are no DERs interconnected. Therefore, the maps will have pop-up boxes that display the DER s currently interconnected and DER projects that are in the interconnection queue process.").

118 *Id*. at p. 12 ("Hosting capacity was one of the most frequent topics discussed in the comments. Commenters on the Initial DSIPs generally noted that the information currently provided by the Utilities is insufficient and that more data related to hosting capacity is needed.").

119 *Id*. at p. 14.

120 *Id*. at pp. 14-15.

121 The directive came in the form of amendments to Minnesota's transmission-planning statute, Minn. Stat § 216B.2425, and required covered utilities "to conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and . . . identify necessary distribution upgrades to support the continued development of distributed generation resources." Minn. Stat. § 216B.2425, subd. 8.

122 MN Public Utilities Commission, Dkt. E002/M-15-962, Order Certifying Advanced Distribution-Management System (ADMS) Project Under Minn. Stat. § 216B.2425 and Requiring Distribution Study (June 28, 2016).

123 MN Public Utilities Commission, Dkt. E002/M-15-962, In the Matter of Northern States Power Company's 2015 Biennial Distribution Grid Modernization Report (Dec. 1, 2016).

124 *Id*. at p. 11.

125 *Id*.

126 *Id*. at Attachment A.

127 MN Public Utilities Commission, Dkt. E002/M-15-962, Information Request PUC #1 (Feb. 21, 2017).

128 MN Public Utilities Commission, Dkt. E002/M-15-962, Notice of Comment Period on Distribution System Study (Feb. 21, 2017).

129 MN Public Utilities Commission, Notice of Commission Meeting (June 2, 2017) (providing notice that the PUC would consider action on Xcel's initial hosting capacity report at its June 15, 2017 hearing).

130 MN Public Utilities Commission, Dkt. E002/M-15-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report (Aug. 1, 2017).

131 *Id*. at p. 5.

132 *Id*. at p. 6.

133 *Id*.

134 Xcel Energy, Dkt. E002/M-17-777, Distribution System/Hosting Capacity Study (Nov. 1, 2017).

135 *Id*. at p. 1-4.

136 MN Public Utilities Commission, Dkt. E999/CI-15-556, Notice of Comment Period on Distribution System Planning Efforts and Considerations (Apr. 21, 2017).

137 *Id*.

138 MN Public Utilities Commission, Dkt. E002/M-15-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report, p. 6 (Aug. 1, 2017).

139 Xcel Energy, Dkt. E002/M-17-777, *Distribution System/Hosting Capacity Study* (Nov. 1, 2017).

140 MN PUC, Dkt. E002/M-17-777, *Notice of Comment Period on Xcel's 2017 Distribution System Hosting Capacity Report* (Nov. 15, 2017).

141 See, e.g., Dkt. E999/CI-15-556, Comments of Interstate Renewable Energy Council, Inc. on Distribution System Planning Efforts and Considerations, pp. 12-14 (Aug. 21, 2017); Dkt. E999/CI-15-556, Comments of the Advanced Energy Economy Institute on Distribution System Planning, p. 5 (July 20, 2017).

142 Xcel Distribution System Study, pp. 6, 10-11; Dkt. E002/M-15-962, Xcel Energy Supplemental Comments on Biennial Distribution Grid Modernization Report, pp. 2-3 (Mar. 20, 2017).

143 *See*, e.g., Dkt. E002/M-15-962, Comments of the Interstate Energy Renewable Energy Council, Inc. Regarding Xcel Energy's Hosting Capacity Analysis and Supplemental Comments, pp. 16-19 (Apr. 20, 2017); Dkt. E002/M-15-962, Comments by Fresh Energy in Response to the Commission's February 2017 Notice, pp. 1-3 (Apr. 20, 2017); MN Public Utilities Commission, Dkt. E002/M-14-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report, pp. 3-4 (Aug. 1, 2017) (summarizing stakeholders' positions).

144 Pepco Holdings, Inc., *Model-Based Integrated High Penetration Renewables Planning Control and Analysis*, pp. 7-10 (Dec. 14, 2015) ("Pepco Analysis"); see also *EPRI, Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV* (Dec. 2012).

145 Pepco Analysis at p. 11.

146 Pepco Holdings LLC, *Interconnection of Distributed Energy Resources*, § 2.6 (Jun. 21, 2016), http://www.pepco.com/uploadedFiles/wwwpepcocom/Content/Page_Content/GPC/PHI%20Interconnection%20of%20Distributed%20Energy%20Resources.pdf.

147 *Id*.

148 Pepco Holdings LLC, Restricted Circuit Map, http://www.pepco.com/Restricted-Circuit-Map.aspx.

149 See Pepco Holdings LLC, Criteria Limits for Distributed Energy Resource Connections to the ACE, DPL and Pepco Distributions Systems (Less than 69KV), http://www.pepco.com/library/templates/Interior.aspx?Pageid=6442460710&LangType=1033

150 Pepco Analysis at pp. 12-16.

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