STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE COMPLAINT OF MORTON SOLAR AND WIND, LLC	**))))**	
RESPONDENT: SOUTHERN INDIANA GAS AND ELECTRIC CO. D/B/A VECTREN ENERGY DELIVERY OF INDIANA	**))))**	**CAUSE NO. 44344**

<u>SUBMISSION OF DIRECT TESTIMONY AND EXHIBITS</u>

Citizens Action Coalition of Indiana, Inc. ("CAC"), by counsel, respectfully submits the following prefiled testimony and exhibits in the above captioned Cause to the Indiana Utility Regulatory Commission.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail or U.S. Mail, first class postage prepaid, this 21st day of January, 2014, on the following:

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RESPONDENT: SOUTHERN INDIANA GAS AND ELECTRIC CO. D/B/A VECTREN ENERGY DELIVERY OF INDIANA	)	**CAUSE NO. 44344**

Direct Testimony of
Sky C. Stanfield, JD

On Behalf of
Citizens Action Coalition of Indiana, Inc.

January 21, 2014

DIRECT TESTIMONY OF SKY C. STANFIELD

ON BEHALF OF CITIZENS ACTION COALITION OF INDIANA, INC.

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Direct Testimony of Sky C. Stanfield
On Behalf of Citizens Action Coalition
Cause No. 44344
January 21, 2014

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name and business address.

A. My name is Sky C. Stanfield. I am an attorney at Keyes, Fox & Weidman, LLP, which is located at 436 14th Street Suite 1305, Oakland, California 94612.

Q. Please describe Keyes, Fox & Weidman, LLP.

A. Keyes, Fox & Wiedman, LLP is a law firm focused on serving clients in the renewable energy and distributed generation sectors. The firm has in-depth experience with all aspects of energy project finance, siting, and approval, as well as the development of regulatory programs and policies to support the expansion of clean energy markets.

Q. Please summarize your work experience and educational background.

A. My practice at Keyes, Fox & Weidman, LLP focuses on the intersection between renewable energy regulation and environmental and land use law, with a particular focus on regulatory policy implementation, compliance and permitting processes. I regularly work on the development and refinement of federally- and state-regulated interconnection standards, playing an active role in improving the clarity and efficiency of interconnection processes across the United States.

As part of my interconnection work, I have directly participated in or overseen my team members in interconnection proceedings before state public utility commissions in California, Hawaii, Massachusetts and Ohio. I have also been active at the Federal Energy Regulatory Commission ("FERC") in proceedings related to interconnection, including the most recent proceeding to update the federal *pro forma* Small Generator

Interconnection Procedures ("SGIP"), which resulted in a final order that FERC issued this past November.[1] I have authored numerous reports related to interconnection and the intersection between interconnection and permitting.[2] In addition to my work on interconnection, I participate in rulemakings before state public utility commissions and FERC regarding the creation of market rate policies for net metering, community solar, wholesale renewables, and related topics.

Prior to joining Keyes, Fox & Wiedman, LLP, I was an associate attorney at Farella, Braun + Martel LLP in San Francisco, CA. I am licensed to practice law in the state of California. I received my J.D. from the University of California at Berkeley School of Law (Boalt Hall) in 2005 and my B.A. from William Smith College in 2000.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Citizens Action Coalition of Indiana, Inc. ("CAC").

Q. Have you testified previously before the Indiana Utility Regulatory Commission ("Commission")?

A. No, I have not.

Q. What is at issue in this proceeding?

A. Morton Solar & Wind, LLC ("Morton Solar"), whose Verified Complaint initiated this proceeding, presents several claims against Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana ("Vectren"), alleging that Vectren has unnecessarily obstructed the interconnection of net metering projects for Morton Solar's clients who are also Vectren customers.[3] This proceeding raises questions and concerns

[1] *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (Nov. 22, 2013), available at https://www.ferc.gov/whats-new/comm-meet/2013/112113/E-1.pdf ("FERC Order No. 792").
[2] For a list of my publications, please see my CV, which is attached as Exhibit SCS-1.
[3] *See* Petitioner's Exhibit A, Direct Testimony of Brad Morton, p. 2 (Sept. 19, 2013) ("Morton Testimony").

about Vectren's policies and practices with respect to the interconnection of net metering customers' distributed generators, and interconnection and net metering policies in Indiana more broadly. Among the relief sought by Morton Solar is a commission investigation and/or rulemaking concerning the broader interconnection practices and policies of Indiana utilities.[4]

Q. What is the purpose of your testimony?

A. My testimony is intended to provide the Commission with my evaluation of the interconnection process in Vectren's service territory and Indiana's interconnections standards more generally, as informed by the information presented in this proceeding with respect to Morton Solar's claims and as compared to national best practices on interconnection. Specifically, my testimony is intended to provide recommendations concerning Vectren's interconnection practices and assist the Commission in determining whether there is a need for a separate proceeding in which the Commission could explore ways to improve the interconnection process in Indiana and facilitate net metering.

Q. What materials did you review in this proceeding in preparation for filing testimony?

A. I have reviewed the verified complaint and answer; testimony and exhibits; and discovery responses. I have also reviewed Indiana's Net Metering Rules and Customer Generator Interconnection Standards, 170 IAC 4-4.2 and 4-4.3; Vectren's Net Metering Rider; and information available on Vectren's website related to net metering and interconnection, including:

[4] Morton Solar's Verified Complaint and Appeal from Consumer Affairs Division, P 29 (June 21, 2013) ("Verified Complaint).

- Customer-Owned Generation (Net Metering) Customer Checklist (Revised June 2013) ("Net Metering Customer Checklist");
- Energy Delivery Interconnection Guidelines for Customer-Owned Generation (Revision 4, signed July 16, 2012) ("Interconnection Guidelines");
- Application for Interconnection (Level 1 - Certified Inverter-Based Generation Equipment 10 kW or Smaller) (Revised June 2013);
- Interconnection Agreement (For Interconnection and Parallel Operation of Certified Inverter-Based Equipment 10 kW or Smaller) (Revised June 2013);
- Application for Interconnection (Level 2 & 3) (Revised June 2013); and
- Interconnection Agreement (For Level 2 or Level 3 Facilities) (Revised June 2013).

Q. Please summarize your conclusions and recommendations.

A. The allegations presented in this proceeding, and the information provided through discovery, reveal a need for a separate Commission investigation and rulemaking proceeding in which the Commission could address broader interconnection and net metering concerns. First, Vectren's process for reviewing interconnection applications and finalizing interconnection agreements, and the Commission's rules on this issue, are not as efficient as they could be. In a separate rulemaking docket, the Commission could take advantage of existing interconnection resources to help it identify appropriate rule updates, which could reduce or eliminate customer complaints of this type in the future and facilitate the process for customers who choose to participate in net metering. Second, Vectren's policy of requiring a disconnect switch for all inverter-based generators, while permitted under the current interconnection standards, places an unnecessary burden on customers. I recommend that the standards be revised to prohibit Indiana utilities from requiring a disconnect switch for small inverter-based generators, which could also be addressed in a rulemaking. Finally, there are several additional areas of improvement that I recommend the Commission explore with respect to interconnection, net metering and supporting utility practices that would remove barriers to, and facilitate greater use of, net metering.

II. EXECUTING AND RETURNING INTERCONNECTION AGREEMENTS

Q. What is your understanding of the issue presented in this proceeding concerning customer access to executed interconnection agreements?

A. Based upon my review of the verified complaint, answer, testimony and discovery responses in this proceeding, it appears that one of the core disputes at issue involves whether, when and how interconnection agreements are signed and shared between Vectren and the applicant. Morton Solar contends that Vectren has failed to timely provide executed interconnection agreements to its clients (or to Morton Solar on its clients' behalf) in accordance with Indiana's interconnection procedures.[5] Vectren denies that it has failed to comply with the deadlines provided in Commission's procedures.[6]

Q. Is the application process and return of executed agreements an important component of the interconnection process as a whole?

A. Yes, I believe it is. At a general level, ensuring that interconnection procedures and supporting processes are clear, fair, transparent and consistently applied is likely the single-most effective way of avoiding disputes like those that have arisen in this

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[5] Verified Complaint, PP 8-12; Morton Testimony, pp. 5-15.
[6] Answer, P 10 (July 12, 2013) ("Vectren denies the remaining allegations in Numerical Paragraph 10.").

proceeding. Procedures and processes that meet these criteria benefit both the utilities and interested customer-generators by improving the efficiency of the process and thereby reducing the overall costs of distributed generation for all parties. More specifically, ensuring that both parties who have executed an interconnection agreement have copies of such agreement is critical to guaranteeing that the rights and responsibilities of both parties are clear and understood. Additionally, both parties must sign the agreement in a timely manner to prevent delay in the development of customer-sited generation.

Q. Is Vectren's current process for reviewing interconnection applications and finalizing interconnection agreements clear?

A. No, I do not believe the process is as clear as it should be. Vectren's Customer Owned Generation webpage[7] contains a link to a Net Metering Customer Checklist.[8] In addition to noting that the customer-generator must submit an application, the checklist specifies that an "[i]nterconnection agreement must be fully complete and signed before interconnecting the generating equipment with Vectren."[9] It is not clear, however, when the interconnection agreement is to be submitted (*e.g.*, along with the application, after notice of approval, or after the utility first sends a signed copy pursuant to the interconnection procedures), nor is there additional information about when the signed agreement will be returned to the applicant. Vectren's Rider NM (Net Metering Rider) provides some explanation of the interconnection requirements, but does not clarify the

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[7] https://www.vectren.com/Business_Customers/Rates_&_Regulatory/Customer-Owned_Generation.jsp (visited on Jan. 9, 2014); *see also* Vectren's Response to CAC Data Request ("DR") No. 2-7 (Jan. 6, 2014). Copies of the data responses cited herein are provided in Exhibit SCS-2.

[8] https://www.vectren.com/cms/assets/pdfs/business/Customer%20Checklist%20for%20Net%20Metering%20Application_June%202013.pdf (visited on Jan. 9, 2014).

[9] *Id.*

interconnection agreement exchange.[10] Vectren's Interconnection Guidelines similarly lack information on the interconnection agreement process.[11] I have been unable to locate any additional written resources on Vectren's website that address these questions.

Q. Has Vectren provided information concerning its interconnection application and agreement process in its responses to data requests in this proceeding?

A. Yes. In its discovery responses and exhibits thereto, Vectren noted that, in the past, the Company has received signed agreements from customers, along with interconnection applications, prior to the Company reviewing the applications and signing the agreements.[12] As a result, "Vectren personnel developed a practice of requesting executed contracts from customers."[13] However, Morton Solar asserts that it did not receive (or received late) copies of fully executed interconnection agreements on behalf of its clients,[14] and as Vectren acknowledged, there was "some confusion as to whether a fully executed agreement was returned to the customer."[15]

It appears that Vectren has changed its policy regarding interconnection applications during the pendency of this proceeding. Specifically, according to its discovery responses, Vectren now executes the agreement first on its end (after receiving and

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[10] Rider NM, Net Metering Rider, Tariff Sheet No. 52 (effective Oct. 13, 2011 and May 3, 2011), available at: http://www.vectren.com/cms/assets/pdfs/south_services_electric_tariff.pdf; *see also* Vectren's Responses to CAC DR No. 2-1.

[11] Energy Delivery Interconnection Guidelines for Customer Owned Generation, available at: https://www.vectren.com/cms/assets/pdfs/business/VEC-006%20Vec%20Eng%20Intercon%20Guidelines%20for%20Cust-Owned%20Gen%20R3.pdf; *see also* Vectren's Response to CAC DR No. 2-2.

[12] Vectren Responses to Morton Solar's DR Nos. 3-2(a), 3-4(a) and Exhibit DR 3-6 (Petitioner's Exhibits BM-23 and BM-24); Vectren's Response to Morton Solar's DR No. 1-1(k).

[13] Vectren's Response to Morton Solar's DR No. 1-1(k) (Petitioner's Exhibit BM-18).

[14] Morton Testimony, pp. 8-10.

[15] Vectren's Responses to Morton Solar's DR. Nos. 3-2(a), 3-4(a); *see also* Exhibit DR 3-6 (Petitioner's Exhibits BM-23 and BM-24); Vectren's Response to Morton Solar's DR No. 1-1(k) ("Vectren did not, as a general rule, return copies of the fully executed interconnection agreements to customers unless copies were requested."). *But see* Vectren's Supplemental Response to Morton Solar's DR No. 1-1(l) (stating that after further investigation, "Vectren did have procedures in place to mail fully executed interconnection agreements to customers upon satisfaction of all criteria. Vectren's Contract Administrator for New Business mailed the agreements.").

approving an interconnection application) and then sends the agreement to the customer.[16] The customer, who must then sign and return the agreement, can retain a copy of the fully executed agreement before sending it back.[17]

While it appears that Vectren has implemented an internal policy that allows customers to copy fully executed interconnection agreements before returning them to the Company, this policy and the steps necessary on both the customer and utility side, particularly for Level 1 applicants, are not transparently explained in the materials available on Vectren's website. It is my opinion that without clear policies – provided in writing and available in a publicly accessible location – there is significant opportunity for additional disputes and confusion to arise. I recommend that Vectren clarify its procedures in its interconnection materials.

Q. You have talked about Vectren's practices in the handling of interconnection agreements. Are Indiana's current interconnection procedures clear and straightforward on this issue?

A. The procedures in Indiana for exchanging interconnection agreements are clear, but could be simplified for Level 1 customers. The Indiana Customer-Generator Interconnection Standards, as set out in 170 IAC 4-4-.3, provide that for Level 1 review, the utility shall, within 10 business days after sending notice of approval, "[e]xecute and send to the applicant a Level 1 interconnection agreement." 170 IAC 4-4.3-6(k)(2). The applicant is then directed to execute the agreement and return it to the utility within 10 business days before starting operation of the customer-generator facility. 170 IAC 4-4.3-6(l)(1)-(2).

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[16] Vectren's Responses to Morton Solar's DR. Nos. 3-5, 3-6 and Exhibit DR 3-6 (Petitioner's Exhibits BM-23 and 24).
[17] *Id.*

These procedures could be simplified by requiring one less step in the exchange of interconnection agreements.

Q. Please explain how Indiana's current Level 1 procedures could be simplified.

A. The Commission could adopt a combined interconnection application and agreement process, as set out in the Model Interconnection Procedures prepared by the Interstate Renewable Energy Council ("IREC Model Rules")[18] and the federal Small Generator Interconnection Procedures ("SGIP").[19] Rather than applicants submitting an application and then separately executing and returning an interconnection agreement upon application approval and receipt of the agreement signed by the utility, as currently provided for in section 170 IAC 4-4.3-6(k),(l), the IREC Model Rules combine the application and agreement. Thus, once the utility completes review of the application and determines that the applicant meets all of the applicable Level 1 screens, the utility merely needs to sign the agreement *and return it to the customer*. This approach reduces the amount of paperwork that has to be submitted by the applicant, thereby increasing the number of "complete" application packages received by the utility. It also reduces the number of documents that need to be separately tracked and exchanged between the customer and the utility. This approach is also followed by the 10 kW inverter process in the federal SGIP and by several states.

It appears that Vectren's old practice of receiving applications and signed agreements together (at least some of the time) is similar to the first step in the simplified process described above. A critical difference, however, is that Vectren did not appear to have a

[18] Model Interconnection Procedures, Interstate Renewable Energy Council, 2013 Edition, available at: http://www.irecusa.org/wp-content/uploads/2013-IREC-Interconnection-Model-Procedures.pdf. Attached as Exhibit SCS-3.
[19] FERC Order No. 792.

clear and consistent practice of returning the executed agreement to the customer upon approval. The confusion resulting from Vectren's old practice underscores the need for interconnection procedures and supporting practices in Indiana to be sufficiently clear and detailed in order to avoid disputes and interconnection delays.

Q. In light of your observations concerning Vectren's interconnection application and agreement process and Indiana's interconnection standards, what do you recommend?

A. I recommend that the Commission examine ways to improve the interconnection agreement process in a separate rulemaking docket. In such a docket, the Commission could take advantage of existing interconnection resources that state utility commissions have used to help evaluate existing interconnection procedures and identify appropriate updates to improve the interconnection agreement process and other related steps.

Specifically, the 2013 IREC Model Rules, which is a compilation of the best practices in interconnection, could serve as a valuable resource in Indiana. As I mentioned previously, the IREC Model Rules follow a simplified approach for Level 1 customers that may be instructive in Indiana. In reviewing the Indiana interconnection procedures and the customer-generation website for Vectren, a few other possible related improvements are easily identified.

Q. Please describe these additional improvements.

A. First, the websites of Vectren and the other investor-owned utilities should have a clear explanation of how applications should be submitted, what they need to include to be considered complete, how the utility will communicate with the applicant about their application review, and links to all relevant forms and agreements.

Second, a single point-of-contact should be identified for each applicant for the *entire* process. Indiana's general interconnection provisions require that each utility designate a contact person or office from which an eligible customer can obtain basic application forms and information through an informal process. Rule 170 IAC 4-4.3-4. Vectren's central point of contact for initial customer inquiries and requests is Customer Planning and Sales.[20] However, it appears from discovery that Mr. Morton's contact, for example, varied and at least once included an individual outside of the Sales division.[21] Although utility employees other than the designated contact person work on matters related to interconnection, a consistent single-point-of-contact could help navigate the process for the application and avoid confusion.

Third, in order to minimize paperwork and increase the efficiency of the review process, some states are also moving toward adoption of online application submittal and allowance of electronic signatures.[22,23]

Finally, though the enhancements identified above will help to minimize the number of disputes that arise, the Commission may also want to consider a process for formally overseeing the interconnection process. This may include requiring the utilities to file periodic reports regarding the number of applications submitted, the timelines for review of those applications, any costs assessed for studies and upgrades for Level 2 and 3

[20] Vectren's Response to CAC DR. No. 2-8.
[21] Attachments to Morton Solar's Response to Vectren DR No. 1-16.
[22] For additional discussion of the benefits of online submittal and electronic signatures, *see* Kevin Fox, *et al.*, *Updating Small Generator Interconnection Procedures*, National Renewable Energy Laboratories, at pp. 17-19 (Dec. 2012), available at: http://www.nrel.gov/docs/fy13osti/56790.pdf. Attached as Exhibit SCS-4.
[23] Vectren allows applications to be submitted via the website; however, it does not appear that agreements can be submitted online. Vectren's Response to CAC DR No. 2-8.

projects, and other relevant information.[24] Alternatively, rather than requiring a separate report, the Commission could incorporate this information into the filing requirements for the utilities' annual net metering reports under 170 IAC § 4-4.2-9(c). Using this information, the Commission will be able to identify if there are problem areas that need to be addressed more comprehensively outside of the formal complaint process. The Commission may also find the creation of a specific dispute resolution process for the interconnection process to be an effective way to manage conflicts between interconnection customers and the regulated utilities. The IREC Model Rules include a dispute resolution process that could serve as a relevant example.[25]

III. EXTERNAL DISCONNECT SWITCHES

Q. Another issue presented in this proceeding pertains to external disconnect switches. What is your understanding of Vectren's policy concerning external disconnect switches for interconnections?

A. According to the Interconnection Guidelines and Net Metering Customer Checklist, Vectren requires a disconnect switch for all customer-owned generation.[26] The Indiana interconnection standards state that utilities "*may* require the applicant to include a

[24] For an example of reporting requirements, *see* Massachusetts Department of Public Utilities, Order on the Distributed Generation Working Group's Redlined Tariff and Non-Tariff Recommendations, DPU 11-75-E, (March 13, 2013) (pp. 29-30), available at: http://www.env.state.ma.us/dpu/docs/electric/11-75/11-75-Filing-1809.pdf ("Regarding the monthly tracking data that the Distribution Companies will report to DOER, we direct the Distribution Companies to maintain that data and make it available to the Department upon request."). The data is available at: https://sites.google.com/site/massdgic/home/interconnection. *See also* California Public Utilities Commission, *Decision Adopting Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations – Electric Tariff Rule 21 and Granting Motions to Adopt the Utilities' Rule 21 Transition Plans*, Decision 12-09-018 (Sept. 13, 2012) (Attachment A, p. 8).

[25] IREC Model Rules at 23.

[26] Interconnection Guidelines, pp. 10-11; Net Metering Customer Checklist ("A generator disconnect switch must be provided by the Customer. Switch must have a visible open gap when in the open position and be capable of being locked in the open position."). *See also* Vectren's Response to CAC DR No. 2-9 ("Pursuant to 170 IAC 4-4.3-4(d), Vectren South requires a disconnect adjacent to each net meter.").

disconnection switch as a supplement to the equipment package." 170 IAC § 4-4.3-4(d) (emphasis added).

Q. Should a utility require disconnect switches for all interconnections?

A. No. In my view, requiring an external disconnect switch for small inverter-based generators is unnecessary to protect the safety of utility workers or the safe and reliable functioning of the grid. In most cases, such a requirement results in significant added costs for customer-generators while duplicating safety functionality that exists in certified inverters.

Indiana's interconnection standards require that generators seeking to qualify for Level 1 or 2 interconnection review be certified to comply with Underwrite Laboratories (UL) 1741, as applicable. 170 § IAC 4-4.3-5(a)(2). All UL 1741 certified inverters meet Institute of Electrical and Electronic Engineers (IEEE) 1547-2003 standard and, therefore, have automatic shut-off capabilities integrated into their systems.[27] As a result of these standards, all certified inverters would stop power flow to the grid automatically in the event the grid goes down in an emergency or for routine maintenance.[28] This means that certified inverter-based renewable energy systems are already equipped with the capability to stop the flow of electricity back to the grid. Thus, a requirement that customers using inverter-based systems pay for and install disconnect switches could unnecessarily hamper the success of renewable energy growth in the State of Indiana, without providing meaningful additional safety protections.

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[27] *See* Institute of Electrical and Electronics Engineers (IEEE). (2003) *1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.*

[28] *See* Laurel Varnado and Michael Sheehan (2009) *Connecting to the Grid: A Guide To Distributed Generation Interconnection Issues.* Sixth ed. IREC and North Carolina Solar Center, at pp. 31-32.

Q. Have there been technical evaluations of the need for external disconnect switches?

A. Yes, two valuable technical reports have been written on this subject, finding that external disconnect switch requirements are unnecessarily duplicative. The National Renewable Energy Laboratory (NREL) published a report in 2008 that evaluated the need for external disconnect switches and concluded that the switch is made redundant and unnecessary by UL and IEEE standards and the extensive safety training utility workers receive.[29] In addition, the Solar America Board for Codes and Standards (Solar ABCs) published a comprehensive review of this issue in 2008 and similarly concluded that for "properly designed and installed Code-compliant PV systems, the [Utility External Disconnect Switch] provides little, if any, additional safety, beyond what is already present."[30] Indeed, the Solar ABCs report makes the interesting observation that some of the utilities that have voluntarily opted to no longer require disconnect switches are those with some of the highest volume of distributed renewable generation in the country.[31] As a result of these studies and the experience of numerous states[32] that prohibit disconnect switches for inverter-based generators, *Freeing the Grid*, the annual report that grades state net metering and interconnection standards, specifically includes the removal of external disconnect switch requirements as one of the key grading criteria.[33] I

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[29] Coddington, M.H., R.M. Margolis, and J. Aabakken (2008) *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*. National Renewable Energy Laboratory. Technical Report: NREL/TP-581-42675, available at: www.nrel.gov/docs/fy08osti/42675.pdf. Attached as Exhibit SCS-5.

[30] Sheehan, Michael T., P.E. (2008) *Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement*, published by Solar America Board for Codes and Standards, available at: http://www.solarabcs.org/about/publications/reports/ued/index.htm. Attached as Exhibit SCS-6.

[31] *Id.* at 2.

[32] At least eleven different states prohibit external disconnect switches for certain generators, including Maine, North Carolina and voluntary steps in California. *See* http://www.dsireusa.org/ (individual state policies on external disconnect switches can be found on the interconnection policy page for each state).

[33] *Freeing the Grid* (2013) published by the Interstate Renewable Energy Council, the Vote Solar Initiative and the Network for New Energy Choices, pp. 9, 27, 46-47, available at: http://freeingthegrid.org/wp-content/uploads/2013/11/FTG_2013.pdf .

should note that while Indiana interconnection standards rate relatively well in many of the other categories, Indiana's standards fail to get an A as a result of the permissive disconnect switch standard.

Q. Please summarize your recommendation on the external disconnect issue.

A. In sum, it is my opinion that Vectren's policy of requiring a disconnect switch for all inverter-based generators places an unnecessary burden on customers and distributed generators. Indiana's procedures currently give utilities the discretion to require such switches. The best way to resolve this issue would be to update the Indiana interconnection standards to prohibit all Indiana utilities from requiring a disconnect switch for small inverter-based generators. This issue could be explored in a separate Commission interconnection rulemaking.

IV. OTHER POTENTIAL INTERCONNECTION AND NET METERING IMPROVEMENTS

Q. Are there additional modifications to the interconnection standards and processes that you believe would facilitate greater utilization of renewable energy in Indiana?

A. Yes, I believe that there are a number of additional improvements that could be made to the interconnection standards and supporting utility practices that would remove barriers for interconnection and facilitate greater use of net metering. These changes would better align Indiana's interconnection standards with national best practices, which have evolved substantially since the Commission's rules were established in 2006. I further believe these changes could result in a more efficient process for the state's utilities and customers without jeopardizing the safe and reliable operation of the state's electrical system.

Q. What additional changes do you recommend?

A. The updated federal SGIP provide a good starting point. In November of last year (2013), FERC issued a decision updating SGIP in order to better enable those procedures to meet the changing realities of an energy market where distributed generation is more common.[34] Many of the changes adopted by FERC are modeled upon best practices in interconnection that have emerged in recent years from states that have significant experience interconnecting high volumes of distributed generation.[35] SGIP has long served as a model for state procedures,[36] and I believe these recent updates suggest that it may be time for Indiana to consider updating its procedures to help facilitate growth in small renewable generation.

Additionally, because transmission providers, Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) must update their federally jurisdictional procedures this year to comply with the FERC order,[37] it makes sense to capitalize on this momentum and contemporaneously consider updates to state procedures. Indiana's

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[34] FERC Order No. 792.

[35] *Id.* at PP 114, 117; 142 FERC ¶ 61,049 at P 49; *see also* California Public Utilities Commission, *Decision Adopting Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations – Electric Tariff Rule 21 and Granting Motions to Adopt the Utilities' Rule 21 Transition Plans*, Decision 12-09-018, adopted September 13, 2012 (Attachment A, p. 8); Hawaii Public Utilities Commission, *Reliability Standards Working Group Independent Facilitator's Submittal and Final Report*, Docket 2011-0206, Attachment 4, PV Sub-Group Final Report (March 25, 2013); and Mass. Dept. of Pub. Utils., Order on the Distributed Generation Working Group's Redlined Tariff and Non-Tariff Recommendations, D.P.U. 11-75-E (March 13, 2013), *available at*: http://www.env.state.ma.us/dpu/docs/electric/11-75/11-75-Filing-1809.pdf.

[36] *See* FERC Order No. 792 at P 15 ("Further, the Commission noted that in addition to the proposed reforms applying to Commission-jurisdictional interconnections, the Commission intended that the proposed reforms serve as a model for state interconnection rules"), P 27 ("Similar to our approach in Order No. 2006, our hope is that states may find this rule helpful in formulating or updating their own interconnection rules, but states are under no obligation to adopt the provisions of this Final Rule); FERC Order No. 2006 at P 512. *See also* Exhibit SCS-4, pp. 4-7 (providing background on the history and evolution of interconnection procedures in the United States).

[37] FERC Order No. 792 at P 262-276.

neighboring state of Ohio did exactly that in December when it significantly updated the state's interconnection procedures in a manner similar to those outlined by FERC.[38]

Q. What are some of the changes to SGIP that should be considered in Indiana?

A. The changes to SGIP focused largely on improvements to the Fast Track and Supplemental Review processes that apply to generators under 5 MWs.[39] This focus is appropriate in Indiana as well because the majority of the distributed generation applications appear to be for small projects.[40] Some of the key changes adopted in the FERC order that I believe may be relevant in Indiana include:

- Incorporation of a pre-application report process that enables greater transparency regarding system information to help distributed generation developers better identify appropriate project locations;[41]

- Updated eligibility limits for Fast Track (or Level 2) review in a manner that takes system information and project location into account in determining the size limits. Instead of utilizing a single threshold across the entire system, the new size limits vary depending upon the generator type, the voltage of the line at the point of interconnection, the thickness of the wire, and the generator's distance from the substation;[42] and

- Changes to the supplemental review process that enable a greater number of projects to interconnect without the need for full study, while also providing utilities with additional time to verify safety, reliability and power quality.[43]

Many of the changes adopted by FERC received support from utilities, ISOs and RTOs across the United States.[44]

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[38] Ohio Public Utilities Commission, 12-2051-EL-ORD, pp. 3-6 (Dec. 4, 2013), available at: http://dis.puc.state.oh.us/TiffToPDf/A1001001A13L04B42903E62593.pdf.
[39] FERC Order 792 at P 21-27.
[40] Vectren's Response to Morton Solar's DR No. 1-1, Vectren Exhibit MS 1-1 (August 23, 2013) (Petitioner's Exhibit BM-18). *See also* IURC, *2012 Annual Summary Report*, (March 2012), available at: http://www.in.gov/iurc/files/2012_Net_Metering_Required_Reporting_Summary.pdf.
[41] FERC Order 792 at P 28-82.
[42] *Id.* at P 83-111.
[43] *Id.* at P 112-189.
[44] *Id.* at P 16-19 (referencing support for an update to SGIP from organizations such as the California Independent System Operator, International Transmission Company, Midcontinent Independent System Operator, Inc. and the National Association of Regulatory Utility Commissioners); P 13-14 (noting the establishment of a working group including the National Rural Electric Cooperative Association, Edison Electric Institute and the American Public

Q. Are there other interconnection improvements the Commission should consider in a separate investigatory or rulemaking docket?

A. Yes. In a report I recently co-authored on behalf of the National Renewable Energy Laboratories (NREL), my colleagues and I identified a number of changes that could be relevant in Indiana, where the majority of the projects appear to be in the 25 kW or below size range.[45] The report identifies the benefits of ensuring the quick and efficient review of small inverter based systems. Due to their size, these systems rarely pose meaningful impacts to the electrical system and can often be reviewed quickly. There can also be a significant volume of these projects once net metering programs gain their footing and thus it benefits the utilities to have simple and efficient procedures for handling the applications. In the report, we recommend increasing the size limit of Level 1 review from 10 kW to 25 kW, shortening processing timelines, and allowing for online application submittal and electronic signatures. Ohio adopted some of these improvements, including increasing eligibility for their Level 1 review process from 10 kW to 25 kW.[46]

Power Association that resulted in agreement on proposed revisions to the Fast Track size limits and aspects of the pre-application report that FERC ultimately adopted); P 54-56; P 96-97.

[45] Exhibit SCS-4, pp. 13-19; *supra* note 40.

[46] *Supra* note 38.

V. RECOMMENDED NEXT STEPS

Q. You have presented several potential changes to Indiana's interconnections standards for the Commission's consideration. Are you recommending that the Commission implement all of these changes in this proceeding?

A. No, I am not. While I believe that Morton Solar's complaint highlights the need for updating or reforming some of the existing procedures and practices with respect to interconnection, I do not believe this is the best proceeding in which to implement all of the changes I recommend. Rather, I recommend that the Commission initiate a separate rulemaking docket in which to explore potential reforms to the interconnection standards, which is one of the recommendations proffered by Morton Solar in this proceeding.[47]

Q. Why should the Commission initiate a proceeding to explore improving interconnections standards?

A. Under the Commission's leadership, Indiana's net metering rules were greatly improved in 2011 by, among other things, expanding the program to all customers and increasing the aggregate sales level under each utility's net metering tariff. Indiana's interconnection standards would similarly benefit from a reevaluation and update to reflect some or all of the changes I have discussed above. As in the case of the net metering rules, an interconnection proceeding could examine potential improvements to make it easier for consumers to take advantage of the renewable energy generated at their homes and businesses to lower utility bills, and stimulate growth within Indiana's economy. This would also further Indiana's policy of developing a robust and diverse energy portfolio, including the use of renewable energy resources.[48]

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[47] Morton Testimony at 24.
[48] I.C. §8-1-8.8-1 (2013).

Q. Should the Commission also explore other ways to improve the net metering process?

A. Yes. According to the IURC's 2012 Net Metering Required Reporting Summary, there were 388 participants statewide, including just 35 in Vectren's service territory.[49] The interconnection improvements I discussed earlier will help minimize some of the barriers to net metering. However, there are other changes the Commission could consider. For example, the definition of "net metering customer" in the current net metering rule limits the participation to one that "owns and operates" the system.[50] However, many customers who would like to use distributed generation at their homes or businesses lack the upfront capital to do so, or do not wish to operate and maintain the actual system. Third party power purchase agreements would allow a developer to build and own the system, and then sell the power back to the customer, alleviating the need for initial costs and responsibilities for operations and maintenance.[51]

Allowing for aggregate net metering is another possible change to the net metering rule that could increase participation. Since many local governments, school systems, and other entities typically have multiple accounts and meters, they may not be able to fully take advantage of net metering in Indiana. Aggregate net metering would allow the customer to apply net excess generation over multiple meters on contiguous parcels owned or controlled by the customer, such as allowing a school system or group of municipal buildings to share a wind turbine. Similarly, community net metering would

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[49] *See* IURC 2012 Net Metering Required Reporting Summary at pp. 7-14, available at: http://www.in.gov/iurc/files/2012_Net_Metering_Required_Reporting_Summary.pdf.
[50] 170 § IAC 4-4.2-1(j).
[51] *See* Katharine Kollins, *et al., Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners*, National Renewable Energy Laboratories, (Rev'd. Feb. 2010) available at: http://www.nrel.gov/docs/fy10osti/46723.pdf.

allow *different* customers with their own meters but contiguous properties in a neighborhood to apply net excess generation amongst several customers. Finally, virtual net metering would allow net metering amongst non-contiguous properties of the same customer, such as a chain of restaurants or gas stations. The Commission could explore these options to increase net metering participation, in addition to investigating interconnection improvements to remove barriers to net metering in the state.

VI. CONCLUSION

Q. Please summarize your conclusions and recommendations

A. The complaint, answer, testimony, exhibits, and discovery documents filed or produced in this proceeding demonstrate that the Indiana interconnection standards, and Vectren's processes for implementing those standards, should be improved to facilitate the efficient interconnection of small generators. As it stands, the interconnection process could act as a deterrent to significant customer utilization of Indiana's net metering program.

Specifically, the standards and supporting practices should be updated to simplify the manner in which interconnection agreements are exchanged and executed. The Indiana interconnection standards should also prohibit utilities from requiring disconnect switches for small inverter-based generators because such a requirement is not necessary to protect the safety of utility workers or the safe and reliable functioning of the grid, and raises the cost of interconnection. The Commission should consider adopting additional changes along the lines of the reforms outlined in the IREC Model Rules and the recent FERC SGIP update. Taken together, these improvements could help ensure that the interconnection process facilitates, rather than hinders, net metering. Finally, increased flexibility within the net metering rule could allow for greater net metering participation within Indiana. It is my opinion that these changes would be best considered and addressed through the opening of a separate rulemaking focused specifically on interconnection and net metering.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

I, Sky C. Stanfield, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

	1/21/14
Sky C. Stanfield, JD	Date

Exhibit SCS-1

Curriculum Vitae of Sky C. Stanfield

Exhibit SCS-1

SKY C. STANFIELD

KEYES, FOX & WIEDMAN LLP

436 14th Street, Suite 1305, Oakland, CA 94612 ▪ (510) 314-8204 ▪ sstanfield@kfwlaw.com

PROFESSIONAL EXPERIENCE

Keyes, Fox & Wiedman LLP, Oakland, CA
Of Counsel (May 2010-Present)

Represent clients before state Public Utilities Commissions and the Federal Energy Regulatory Commission (FERC) in rulemakings and other proceedings affecting formation of the market for distributed renewables. Lead efforts to reform interconnection procedures across the United States, including significant efforts in California, Hawaii, Massachusetts and at FERC. Thought leader in the streamlining of the municipal solar permitting process. Assist clients with the permitting process for solar installations, including interconnection, environmental and land use permitting, and participation in utility procurement programs.

Farella, Braun + Martel, LLP, San Francisco, CA
Associate Attorney (October 2006-April 2010)

Provided regulatory compliance advice to clients operating under federal and state environmental statutory regimes. Negotiated with public agencies regarding permitting and enforcement actions and litigated those claims when necessary. Aided solar clients with the environmental review process, including NEPA, CEQA and ESA compliance. Acted as lead plaintiffs' attorney on significant FLPMA/NEPA case challenging off-road vehicle route proliferation on public lands. Drafted memoranda advising clients on AB32, SB375 and other climate legislation. Spoke at events on climate change, sustainability and land use related topics.

Honorable Lawrence K. Karlton, Senior Judge, United States District Court, Eastern District of California, Sacramento, CA
Law Clerk (May 2005-May 2006)

Drafted legal memoranda and proposed orders on all aspects of a major environmental law case concerning distribution of water and restoration of fisheries in the San Joaquin River. Conducted research regarding federal water contracts, the Reclamation Act, the California Constitution, NEPA, the ESA, and remedies.

PROFESSIONAL AWARDS

***California Lawyer* Magazine's Attorney of the Year (CLAY) Award Recipient for 2010**

***Super Lawyers*, Northern California "Rising Star", 2011 – 2013**

EDUCATION

Boalt Hall School of Law, University of California, Berkeley - J.D., May 2005
Honors: Joe Sax Environmental Fellowship, 2003
American Jurisprudence Award in California Environmental Issues
Environmental Law Certificate

William Smith College, Geneva, NY - B.A., *magna cum laude*, Environmental Studies, June 2000

Honors: Phi Beta Kappa

High Honors for Thesis in Environmental Studies, *Reducing Carbon Emissions from Transportation: The Potential of Alternative Fuel Vehicles*

Kenneth E. Carle Award for academic excellence in Environmental Studies, 2000

PUBLICATIONS & PRESENTATIONS

Articles and Reports

Sky Stanfield, et al., *Minimizing Overlap in PV System Approval Processes: Case Studies and Analysis*, Interstate Renewable Energy Council, October 2013.

Sky Stanfield and Don Hughes, *Model Inspection Checklist for Rooftop PV Systems*, Interstate Renewable Energy Council, September 2013.

Sky Stanfield, Erica Schroeder and Thad Culley, *Sharing Success: Emerging Approaches to Efficient Rooftop Solar Permitting*, Interstate Renewable Energy Council, April 2012.

Kevin Fox, Sky Stanfield, et al., *Updating Small Generator Interconnection Procedures for New Market Conditions*, National Renewable Energy Laboratory, December 2012.

Sky Stanfield, *Blueprint for the Development of Distributed Generation in California*, Interstate Renewable Energy Council, February 2013.

Sky Stanfield and Douglas Ruley, *Greenhouse Gas Regulation and Litigation: Opportunities To Move Renewable Energy Forward and Get the Job Growth Message Out*, Solar Today, June 2011.

Sky Stanfield and Steve Vettel, *On the Hot Seat: Climate Action Plans Become a New Reality for California Cities' Long-Term Master Plans and Land Use Documents*, The Registry, July 2009

Sky Stanfield, *The Mobile Source Air Toxics Rule: How Does the Greatest Reduction Become No Reduction?*, 31 ECOLOGY L.Q. 563 (2004).

Speaking Engagements

12/11/13 Maintaining Distributed Solar Growth in the U.S.: Trends and Needed Reform, Sierra Club, Sonoma, CA.

10/22/13 Interconnection Issues at Higher Penetrations, Interstate Renewable Energy Council 3iForum, Solar Power International, Chicago, IL.

10/22/13 Improving Interconnection: Integrated Distribution Planning, Interstate Renewable Energy Council 3iForum, Solar Power International, Chicago, IL.

09/25/13 Embracing the Challenges and Opportunities: Interconnection for Wholesale Distributed Generation, PV Optimization Seminar, PV Insider, San Jose, CA.

06/05/13 Project Permit: Simplifying Municipal Solar Permitting Practices, Vote Solar Initiative "Get Some Sun" Webinar.

05/01/13 Efficient Solar Permitting for Your Jurisdiction: Westchester County, NY, Interstate Renewable Energy Council and ICLEI, White Plains, NY.

04/04/13 Efficient Solar Permitting for Your Jurisdiction: Eastern Sierras, Interstate Renewable Energy Council and ICLEI, Mammoth Lakes, CA.

03/21/13 Efficient Solar Permitting for Your Jurisdiction: Alameda County, CA, Interstate Renewable Energy Council and ICLEI, Livermore, CA.

02/05/13 Using System Information to Improve Efficiency of the Interconnection Process, PV America East, Philadelphia, PA.

12/13/12 Getting to Know the New California Rule 21, Solar Energy Industries Association, Webinar.

09/10/12 Promoting a New Era of Solar Permitting in the United States, Interstate Renewable Energy Council Annual Meeting, Orlando, FL.

06/26/12 Improving the Efficiency of the Rooftop Solar Permitting Process, California Center for Sustainable Energy, Webinar.

06/06/12 Improving the Efficiency of the Rooftop Solar Permitting Process, ICLEI, DOE SunShot Webinar, available at: http://www.icleiusa.org/training-events/improving-the-efficiency-of-the-rooftop-solar-permitting-process.

04/13/12 Transmission and Siting: The Mechanics of Solar Development, University of California at Davis, Environmental Law Symposium: "Solar Energy Siting in California."

04/28/11 California's Renewable Energy Policy Goals: Can We Meet Them?, San Francisco Bar Association, San Francisco, CA.

03/29/11 Break Out Session on Permitting and Interconnection, SolarTech Leadership Summit, Santa Clara, CA.

03/16/11 California Interconnection 101 An Update on Reform: What's Happening and Why it is Important, VoteSolar/Interstate Renewable Energy Council Webinar, available at: http://votesolar.org/resources/get-some-sun-solar-webinars/.

02/10/11 Interconnection Panel, SolarTech Permitting & Interconnection Symposium, Irwindale, CA.

12/02/10 The State of Distributed Generation Panel, Power to the People Distributed Generation & Microgrids, Berkeley-Stanford CleanTech Conference, San Francisco, CA.

01/26/10 Project Development: Planning Ahead to Address the New Greenhouse Gas CEQA Guidelines, Farella Braun + Martel Environmental Symposium, San Francisco, CA.

08/06/09 Climate Change Legislation's Impact on the Physical Landscape, BrightTalk Seminar.

03/25/09 SB375, CEQA and Climate Change: Expediting Infill Development, Farella Braun + Martel's 2009 Developers Conference: Moving Forward in Tough Times, San Francisco, CA.

06/04/08 Everything You Ever Wanted to Know About Greenhouse Gas Emission Reporting Requirements, Farella Braun + Martel's Environmental Practice Group Meeting, San Francisco, CA.

05/15/08 Greening Small Business: For a Profitable and Sustainable Future, Going Green: What Entrepreneurs Need to Know About Being Eco-Friendly, Cisco Campus, San Jose, CA.

PROFESSIONAL AFFILIATIONS

Admitted to the California Bar

Conference of California Public Utility Counsel (CCPUC) – 2010-2013

United States Green Building Council, Northern California Chapter
Member of Land Use Task Force

San Francisco Planning and Urban Research Association (SPUR) – 2009-2010

Member of SB 375 Task Force

Center for Law, Energy, & the Environment (CLEE) – 2005-2009
Alumni Advisor

Farella, Braun + Martel, Women's Initiative Steering Committee – 2009-2010

Exhibit SCS-2

Cited Data Responses

Exhibit SCS-2

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE APPEAL TO THE INDIANA UTILITY REGULATORY COMMISSION FROM THE CONSUMER AFFAIRS DIVISION OF THE RULING ON COMPLAINT BY MORTON SOLAR & WIND, LLC AGAINST VECTREN UTILITY HOLDINGS, INC. d/b/a VECTREN ENERGY DELIVERY OF INDIANA -- SOUTH	)))))))	**CAUSE NO. 44344**

VECTREN SOUTH'S
OBJECTIONS AND RESPONSES TO THE
CITIZENS ACTION COALITION OF INDIANA, INC.
SECOND SET OF DATA REQUESTS TO VECTREN SOUTH

Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South"), pursuant to 170 IAC 1-1.1-16 and the discovery provisions of Rules 26 through 37 of the Indiana Rules of Trial Procedure, by its counsel, hereby submits the following Objections and Responses to Citizens Action Coalition of Indiana, Inc.'s First Set of Data Requests to Vectren South ("Requests").

<u>General Objections</u>

The responses provided to the Requests have been prepared pursuant to a reasonable and diligent investigation and search conducted in connection with the Requests in those areas where information is expected to be found. To the extent the Requests purport to require more than a reasonable and diligent investigation and search, Vectren South objects on grounds that they include an undue burden and unreasonable expense.

2. Vectren South objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and which are not reasonably calculated to lead to the discovery of admissible evidence.

3. Vectren South objects to the Requests (including Instruction Nos. 1(a), 1(b) and 2(d)) to the extent they seek responses and information from individuals and entities who are not parties to this proceeding and to the extent they request the production of information and documents not presently in Vectren South's possession, custody or control.

4. Vectren South objects to the Requests to the extent the Requests seek information outside the scope of this proceeding, and as such, the Requests seek information not reasonably calculated to lead to the discovery of relevant or admissible evidence.

5. Vectren South objects to the Requests to the extent they seek an analysis, calculation, or compilation which has not already been performed and which Vectren South objects to performing.

6. Vectren South objects to the Requests to the extent they are vague and ambiguous and provide no basis from which Vectren South can determine what information is sought.

7. Vectren South assumes no obligation to supplement these responses except to the extent required by Ind. Tr. R. 26(E) (1) and (2) and objects to the extent the instructions and/or Requests (including Instruction No. 2(f)) purport to impose any greater obligation.

8. Vectren South objects to the Requests to the extent they seek information that is subject to the attorney-client, work product, settlement negotiation or other applicable privileges.

9. Vectren South objects to the Requests to the extent the seek information that is confidential, proprietary, competitively sensitive and/or trade secret.

10. The responses constitute the corporate responses of Vectren South and contain information gathered from a variety of sources. Vectren South objects to the Requests (including Instruction Nos. 1(j), 1(k) and 2(g)) to the extent they request identification of and personal information about all persons who participated in responding to each data request on the grounds that they are overbroad and unreasonably burdensome given the nature and scope of the requests and the many people who may be consulted about them. Vectren South will provide the name of the person or persons primarily responsible for each response or the subject matter thereof.

11. Vectren South objects to the Requests to the extent the discovery sought is unreasonably cumulative or duplicative, or is obtainable from some other source that is more convenient, less burdensome, or less expensive.

12. Vectren South objects to the Requests to the extent the burden or expense of the proposed discovery outweighs its likely benefit, taking into account the needs of the case, the amount in controversy, the parties' resources, the importance of the issues at stake in litigation, and the importance of the proposed discovery in resolving the issues.

13. Vectren South objects to the Requests to the extent they solicit copies of voluminous documents.

14. Vectren South objects to the Requests (including Instruction No. 2(h)) to the extent they request identification of witnesses who will be prepared to testify concerning the matters contained in each response on the grounds that Vectren South is under no obligation to call witnesses to response to questions about information provided in discovery.

Subject to and without waiver of the general and specific objections set forth herein, Vectren South responds to the Requests in the manner set forth below.

Q. 2-1 Please provide a copy of the Company's current net metering rider.

a. If applicable, please also provide the hyperlink to the Company's current net metering rider on the Company's website.

Response: The Company's current net metering rider is Rider NM, tariff sheet no. 52, available at https://www.vectren.com/cms/assets/pdfs/south_services_electric_tariff.pdf.

Q. 2-2 To the extent it exists, please provide a copy of the Company's current interconnection rider.

a. If applicable, please also provide the hyperlink to the Company's current interconnection rider on the Company's website.

Response: The Company does not have a specific interconnection rider. However, interconnection guidelines are available at https://www.vectren.com/Business_Customers/Rates_&_Regulatory/Customer-Owned_Generation.jsp.

Q. 2-7 Please provide any interconnection guidelines and other documents or information Vectren provides/makes available to its customers.

a. If applicable, please also provide the hyperlink to the Company's current interconnection guidelines and other documents or information Vectren provides to or posts to its website for customers that want to interconnect.

Response: The Company's current interconnection guidelines and other documents or information made available to customers are available on the Company's website at https://www.vectren.com/Business_Customers/Rates_&_Regulatory/Customer-Owned_Generation.jsp.

Q. 2-8 Please state the number of Vectren employees that handle customer inquiries, requests for information, and/or applications with respect to interconnection.

Response: Customer Planning and Sales ("CPAS") is the central point of contact for initial customer inquiries and requests. Sales is the liaison between all net metering customer requests (and contractors, if any) and pertinent Vectren South departments. Ann-Marie Schapker is the Sales point of contact within Vectren South's electric service territory. In addition to Ms. Schapker, Sales has an additional two representatives and CPAS has four other representatives that are trained to enter orders. Additionally, distribution engineering has nine engineers that can be assigned an order and asset management has one employee that can review orders.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE APPEAL TO THE INDIANA UTILITY REGULATORY COMMISSION FROM THE CONSUMER AFFAIRS DIVISION OF THE RULING ON COMPLAINT BY MORTON SOLAR & WIND, LLC AGAINST VECTREN UTILITY HOLDINGS, INC. d/b/a VECTREN ENERGY DELIVERY OF INDIANA -- SOUTH	))))	**CAUSE NO. 44344**

RESPONDENT'S OBJECTIONS AND RESPONSES TO MORTON SOLAR & WIND LLC'S DATA REQUEST SET NO. 2

Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Company"), pursuant to the Prehearing Conference Order in this Cause, hereby submits the following Objections and Responses to Morton Solar & Wind LLC's Request Set No. 2 served August 12, 2013 ("Requests").

General Objections

All of the following General Objections are incorporated by reference in the response to each of the Requests:

1. The responses provided to the Requests have been prepared pursuant to a reasonable investigation and search conducted in connection with the Requests in those areas where information is expected to be found. To the extent the Requests purport to require more than a reasonable investigation and search, the Company objects on grounds that they seek to impose an undue burden and unreasonable expense and exceed the scope of permissible discovery.

2. To the extent that the Requests seek production of electronically stored information, The Company objects to producing such information from sources that are not reasonably accessible because of undue burden or cost.

3. The responses provided to the Requests set forth the information in reasonably complete detail. To the extent that the requesting party contends that a Request calls for more detail, the Company objects to the Request on the grounds that it is overly broad, seeks to impose an undue burden and unreasonable expense, and exceeds the scope of permissible discovery.

4. The Company objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and to the extent they are not reasonably calculated to lead to the discovery of admissible evidence.

4. The Company objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and to the extent they are not reasonably calculated to lead to the discovery of admissible evidence.

5. The Company objects to the Requests to the extent they seek an analysis, calculation, compilation or study which has not already been performed and which the Company objects to performing.

6. The Company objects to the Requests to the extent they are vague and ambiguous and do not provide a reasonable basis from which the Company can determine what information is sought.

7. The Company objects to the Requests to the extent they seek information that is subject to the attorney-client, work product, settlement negotiation or other applicable privileges.

8. The Company objects to the Requests to the extent they purport to require the Company to supply information in a format other than that in which the Company normally keeps such information.

9. The Company objects to the Requests to the extent that they seek production of documents created during an unreasonably long or unlimited period, on the grounds that the Requests are overly broad, seek to impose an undue burden and unreasonable expense, and exceed the scope of permissible discovery.

10. The Company objects to the Requests to the extent they request the production of information and documents not presently in the Company's possession, custody or control.

11. The Company objects to the Requests (including Paragraph 1(b) of the "Definitions and Instructions") to the extent they request the production of (a) multiple copies of the same document; (b) additional copies of the same document merely because of immaterial or irrelevant differences; and (c) copies of the same information in multiple formats on the grounds that such Requests are irrelevant, overbroad, unreasonably burdensome, unreasonably cumulative and duplicative, not required by the Commission rules, and inconsistent with practice in Commission proceedings.

12. The responses constitute the corporate responses of the Company and contain information gathered from a variety of sources. The Company objects to the Requests (including Paragraph 2(g) of the "Definitions and Instructions") to the extent they request identification of and personal information about all persons who participated in responding to each data request on the grounds that (a) they are overbroad and unreasonably burdensome given the nature and scope of the requests and the many people who may be consulted about them and (b) they seek information that is subject to the attorney client and work product privileges. The Company also objects to the Requests to the extent they request identification of witnesses to be called in the Company's case-in-chief or rebuttal who can answer questions regarding the information supplied in the responses on the grounds that (a) the Company is under no obligation to call witnesses to respond to questions about information provided in discovery and (b) the Requests seek information subject to the work product

privilege.

13. The Company objects to Paragraph 2(b) of the "Definitions and Instructions" on the grounds that it is unreasonably burdensome in light of the scope of the proceeding and the short discovery deadlines, inconsistent with Commission practice, and inconsistent with the informal discovery procedures provided for in the Prehearing Conference Order.

14. The Company assumes no obligation to supplement these responses except to the extent required by Ind. Tr. R. 26(E) (1) and (2) and objects to the extent the "Definitions and Instructions" and/or Requests purport to impose any greater obligation.

Without waiving these objections, the Company responds to the Requests in the manner set forth below.

<u>Request No. 1-1:</u> Attached as "Exhibit A" is a list of Vectren customers who contracted with Morton Solar and who have applied to Vectren for interconnection agreements. For **each** customer on this list, please provide the following information:

a. On what date did you first received an application (whether complete or not) from the customer (or on behalf of the customer) to connect customer-generator facilities from the customer?

b. Does/did you consider the application to fall within "Level 1" interconnection review (170 IAC-4-4.3-6), "Level 2" interconnection review (170 IAC-4-4.3-7), "Level 3" interconnection review (170 IAC-4-4.3-8), or some other review procedure? Please explain why you classify/classified the application this way?

c. How and on what date (if at all) did you notify the customer (or its representative) that the initial application was either complete or incomplete?

d. On what dates did you receive a complete application from the customer (or its representative)?

e. How and on what date (if at all) did you notify the customer that the customer's application was complete?

f. For any customer that submitted a "Level 2" application, on what date(s) did you perform the "initial review" required under 170 IAC 4-4.3-7(q)? Please explain the results of this "initial review" and specify whether that result fell under 170 IAC 4-4.3-7(q)(1), (2), (3), or (4).

g. For any customer that submitted a "Level 3" application, on what date(s) did you perform the "initial review" and "offer the applicant the opportunity to meet with utility staff" as required under 170 IAC 4-4.3-8(b)?

h. For any customer that submitted a "Level 3" application, on what date(s) did you "provide an impact study agreement to the applicant" as required under 170 IAC 4-4.3-8(c)? What was the "good faith estimate" the applicant was asked to pay?

i. For any customer that submitted a "Level 3" application, on what dates did you perform and complete the impact study? Please explain the results of the study, including any estimates for the costs of modifications to the distribution system, whether if required a "facilities study," any estimate for the costs of any facilities study, etc.

j. On what date did you provide the customer with an **executable** interconnection agreement?

k. On what date did you provide the customer with an **executed** interconnection agreement?

<u>Response:</u>

a. Please see <u>Vectren Exhibit MS 1-1</u>.

b. Please see Vectren Exhibit MS 1-1. Only three of the projects identified in Exhibit A qualified for a Level 2 application review. All three projects qualified for a Level 2 application review due to the size of their output, which fell between 10 kilowatts and 2 megawatts. All other projects identified in Exhibit A had an output of less than 10 kilowatts and satisfied the criteria of 170 IAC 4-4.3-6(c) through (h) and were therefore processes under a Level 1 application review.

c. Please see Vectren Exhibit MS 1-1 for the date Vectren informed the customer that its application was incomplete. In some instances, Vectren does not have records indicating the specific date or form of communication with the customer. Vectren informed other customers by electronic mail and telephone that their application was incomplete.

d. Please see Vectren Exhibit MS 1-1.

e. Please see Vectren Exhibit MS 1-1. Vectren does not have records of all communications with customers regarding the completeness of their applications. In some instances, Vectren sent emails and in other instances communication was by telephone.

f. Please see Vectren Exhibit MS 1-1. The Level 2 reviews for Messrs. Krietemeyer and Miller satisfied 170 IAC 4-4.3-7(q)(1). Mr. Stransky's application violated 170 IAC 4-4.3-7(e). Upon further reviews of studies in Vectren's possession, Vectren concluded pursuant to 170 IAC 4-4.3-7(o) that the facility could be interconnected.

g. None of the customers identified in Exhibit A submitted applications qualifying for a Level 3 review.

h. None of the customers identified in Exhibit A submitted applications qualifying for a Level 3 review.

i. None of the customers identified in Exhibit A submitted applications qualifying for a Level 3 review.

j. Please see Vectren Exhibit MS 1-1. Vectren has made an executable interconnection agreement available on its website at:

https://www.vectrenenergy.com/Business_Customers/Rates_&_Regulatory/Customer-Owned_Generation.jsp

In many cases, customer applications included interconnection agreements executed by the customer.

k. Please see Vectren Exhibit MS 1-1 for the dates Vectren provided fully executed interconnection agreements (*i.e.* agreements executed by both Vectren and the customer) to the customers or their agent. This does not represent the date that the interconnection agreements were fully executed by both the customer and Vectren. Because Vectren makes its interconnection agreement available on its website, many customers submit agreements they have already executed. These agreements become binding upon Vectren's execution.

As a result of this practice, Vectren personnel developed a practice of requesting executed contracts from customers. Vectren executed the agreements upon completion of all required steps to initiate the interconnection. In some instances, specifically Nick Davidson and Engelbrecht Orchard, execution was delayed until receipt of proof of insurance. Vectren did not, as a general rule, return copies of the fully executed interconnection agreements to customers unless copies were requested. The dates identified on Vectren Exhibit MS 1-1 reflect the dates the executed interconnection agreements were provided to customers or their agents.

Exhibit SCS-2

			a	b	c	d	e	f	j	k
Customer	**TYPE**	**KW Rating**	**Application first received**	**Level 1, 2 or 3**	**Customer notified application incomplete**	**Complete application received**	**customer notified of complete application**	**Level '2' initial review and explain results**	**EXECUTABLE interconnection agreement sent to customer**	**EXECUTED agreement provided to customer**
Ohio Township Public Library - Bell Road[1]	SOLAR	5.5	no records	1	2/3/2005	no records	no records	n/a	2/3/2005	3/30/2007
Ohio Township Public Library - Bell Road[2]	OFF-GRID SOLAR	n/a	none	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Engelbrecht Orchard	WIND	10	6/19/2008	1	7/28/2008	9/12/2008	9/12/2008	n/a	8/22/2008	1/27/2009
Lincoln Heritage Public Library - Chrisney	SOLAR	10	7/28/2008	1	no records	8/24/2008	8/22/2008	n/a	8/22/2008	1/9/2009
Bill Polk	WIND	1.8	7/24/2008		8/25/2008	no records	no records	n/a	7/28/2008	9/24/2008
VPS Architecture	SOLAR	7.5	3/31/2009	1	no records	4/14/2009	4/14/2009	n/a	1/12/2010	3/31/2009
Erik & Laura Arneberg (New Harmony)	SOLAR	10	3/15/2010	1	3/17/2010	6/24/2010	no records	n/a	6/7/2010	6/30/2010
Evansville-Vand. Central Library	SOLAR	10	4/28/2010	1	5/5/2010	5/14/2010	5/11/2010	n/a	4/26/2010	5/21/2010
Andy Davidson	SOLAR	4	11/11/2009	1	complete	11/11/2009	11/18/2009	n/a	11/24/2009	11/25/2009
Haubstadt Community School	WIND	2.4	5/27/2010 *	1	5/27/2010 *	5/27/2010	5/27/2010	n/a	1/20/2010	6/10/2010
Nick Davidson	SOLAR	5	3/30/2010	1	complete	3/30/2010	3/30/2010	n/a	5/21/2010	5/21/2010
Don Jost	SOLAR	4	3/30/2010	1	complete	3/30/2010	3/30/2010	n/a	4/16/2010	5/13/2010
Tony Kohut	SOLAR	3	4/4/2011	1	4/25/2011	5/11/2011	no records	n/a	5/3/2011	5/17/2011
Chanda Banner	SOLAR	4	6/27/2011	1	complete	6/30/2011	no records	n/a	6/26/2011	7/13/2011
Gary Weiss	SOLAR	3	6/1/2011	1	6/2/2011	7/18/2011	no records	n/a	6/20/2011	7/18/2011
Sharis Goines-Pitt	SOLAR	3	10/25/2011	1	no records	11/7/2011	no records	n/a	10/25/2011	11/28/2011
Bob Martin	SOLAR		1/11/2012	1	order not entered	n/a	n/a	n/a	n/a	n/a
Roy Perry	SOLAR	2.15	12/28/2011	1	no records	1/19/2012	no records	n/a	12/28/2011	2/1/2012
Howell Wetlands[3]	SOLAR	n/a	none	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Denise Vaal	SOLAR	6 and 8	7/25/2012	1	8/20/2012	11/2/2012	11/6/2012	n/a	7/26/2012	11/17/2012
Jeff Osborne	SOLAR	10	4/26/2013	1	complete	4/26/2013	5/6/2013	n/a	5/6/2013	5/20/2013
Randy Ellis	SOLAR	7.525	11/28/2012	1	1/16/2013	5/8/2013	5/8/2013	n/a	11/27/2012	5/8/2013
Dave Krietemeyer	SOLAR	11.825	9/11/2012	2	no records	9/11/2012	no records	9/11/2012	10/8/2012	
Carl Fehrenbacher	SOLAR	8	4/26/2013	1	complete	4/26/2013	4/30/2013	n/a	5/3/2013	5/15/2013
Allen Stute	SOLAR	4.515	12/17/2012	1	no records	12/26/2012	no records	n/a	12/14/2012	
Norm Miller	SOLAR	14.5	11/6/2012	2	11/8/2012	11/16/2012	11/16/2012	11/8/2012	11/6/2012	
Ted Stransky	SOLAR	24.75	3/26/2013	2	4/1/2013-4/5/2013	4/17/2013	no records	4/5/2013	4/16/2013	4/29/2013
James Purviance	SOLAR	5.4	3/19/2013	1	no records	3/21/2003	3/21/2013	n/a	3/13/2013	5/2/2013
Morris Bitzer	SOLAR	8	1/25/2013	1	no records	2/8/2013	no records	n/a	1/11/2013	
Stephen Zehr	SOLAR	3.375	7/5/2013	1	7/9/2013	7/9/2013	7/9/2013	n/a	7/5/2013	7/16/2013

Notes:

n/a denotes not applicable

1 Ohio Township Public-Library--Bell Road's initial application preceeded the effective date of 170 IAC 4-4.3-1 *et seq.*
2 Vectren has no record of a second Ohio Township Public-Library--Bell Road interconnection application for an off-grid solar project.
3 Vectren has no record of an application for interconnection from Howell Wetlands.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE APPEAL TO THE INDIANA UTILITY REGULATORY COMMISSION FROM THE CONSUMER AFFAIRS DIVISION OF THE RULING ON COMPLAINT BY MORTON SOLAR & WIND, LLC AGAINST VECTREN UTILITY HOLDINGS, INC. d/b/a VECTREN ENERGY DELIVERY OF INDIANA -- SOUTH	))))))	**CAUSE NO. 44344**

RESPONDENT'S OBJECTIONS AND RESPONSES TO INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S DATA REQUEST SET NO. 3

Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Company"), pursuant to the Prehearing Conference Order in this Cause, hereby submits the following Objections and Responses to Morton Solar & Wind LLC's Request Set No. 3 served September 10, 2013 ("Requests").

General Objections

All of the following General Objections are incorporated by reference in the response to each of the Requests:

1. The responses provided to the Requests have been prepared pursuant to a reasonable investigation and search conducted in connection with the Requests in those areas where information is expected to be found. To the extent the Requests purport to require more than a reasonable investigation and search, the Company objects on grounds that they seek to impose an undue burden and unreasonable expense and exceed the scope of permissible discovery.

2. To the extent that the Requests seek production of electronically stored information, The Company objects to producing such information from sources that are not reasonably accessible because of undue burden or cost.

3. The responses provided to the Requests set forth the information in reasonably complete detail. To the extent that the requesting party contends that a Request calls for more detail, the Company objects to the Request on the grounds that it is overly broad, seeks to impose an undue burden and unreasonable expense, and exceeds the scope of permissible discovery.

4. The Company objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and to the extent they are not reasonably calculated to lead to the discovery of admissible evidence.

5. The Company objects to the Requests to the extent they seek an analysis, calculation, compilation or study which has not already been performed and which the Company objects to performing.

6. The Company objects to the Requests to the extent they are vague and ambiguous and do not provide a reasonable basis from which the Company can determine what information is sought.

7. The Company objects to the Requests to the extent they seek information that is subject to the attorney-client, work product, settlement negotiation or other applicable privileges.

8. The Company objects to the Requests to the extent they purport to require the Company to supply information in a format other than that in which the Company normally keeps such information.

9. The Company objects to the Requests to the extent that they seek production of documents created during an unreasonably long or unlimited period, on the grounds that the Requests are overly broad, seek to impose an undue burden and unreasonable expense, and exceed the scope of permissible discovery.

10. The Company objects to the Requests to the extent they request the production of information and documents not presently in the Company's possession, custody or control.

11. The Company objects to the Requests (including Paragraph 1(b) of the "Definitions and Instructions") to the extent they request the production of (a) multiple copies of the same document; (b) additional copies of the same document merely because of immaterial or irrelevant differences; and (c) copies of the same information in multiple formats on the grounds that such Requests are irrelevant, overbroad, unreasonably burdensome, unreasonably cumulative and duplicative, not required by the Commission rules, and inconsistent with practice in Commission proceedings.

12. The responses constitute the corporate responses of the Company and contain information gathered from a variety of sources. The Company objects to the Requests (including Paragraph 2(g) of the "Definitions and Instructions") to the extent they request identification of and personal information about all persons who participated in responding to each data request on the grounds that (a) they are overbroad and unreasonably burdensome given the nature and scope of the requests and the many people who may be consulted about them and (b) they seek information that is subject to the attorney client and work product privileges. The Company also objects to the Requests to the extent they request identification of witnesses to be called in the Company's case-in-chief or rebuttal who can answer questions regarding the information supplied in the responses on the grounds that (a) the Company is under no obligation to call witnesses to respond to questions about information provided in discovery and (b) the Requests seek information subject to the work product privilege.

13. The Company objects to Paragraph 2(b) of the "Definitions and Instructions" on the grounds that it is unreasonably burdensome in light of the scope of the proceeding and the short discovery deadlines, inconsistent with Commission practice, and inconsistent with the informal discovery procedures provided for in the Prehearing Conference Order.

14. The Company assumes no obligation to supplement these responses except to the extent required by Ind. Tr. R. 26(E) (1) and (2) and objects to the extent the "Definitions and Instructions" and/or Requests purport to impose any greater obligation.

Without waiving these objections, the Company responds to the Requests in the manner set forth below.

Request No. 3-2: If your responses to any of the requests for admission Nos. 3-1(a) through 3-1(d) are anything other than an unqualified admission, please explain your response.

Response:

a. Vectren did not reject the interconnection agreement tendered by Catherine Patton. Vectren was adhering to the requirements of 170 IAC 4-4.3-6(k)(2) by forwarding a copy of an interconnection agreement executed by Vectren for the customer to return 10 calendar days before operation of the customer-owned generator. This method also ensures that Vectren's customer is the party executing the agreement and has an opportunity to understand the commitments the customer is assuming by executing the agreement. In the past, Vectren has received a signed agreement before signing itself and that practice led to premature interconnections by Morton Solar and to some confusion as to whether a fully executed agreement was returned to the customer. The premature interconnection presents numerous potential safety issues. Please also see Vectren's response to Request No. 3-5.

b. Morton Solar's submission of the interconnection agreement was not Vectren's basis for executing an interconnection agreement and sending it to the customer for review. Vectren was adhering to the Commission's interconnection rules in 170 IAC 4-4.3-1 et seq. For example, a Level 1 interconnection review requires Vectren to execute and send to the customer a Level 1 interconnection agreement within ten (10) business days of sending notice that the application is complete. 170 IAC 4-4.3-6(k)(2). The customer is required to return the executed interconnection agreement ten (10) business days before starting operation of the customer-generator facility. 170 (AC 4-4.3-6(l)(2). Please also see Vectren's response to Request No. 3-5.

c. N/A

d. Morton Solar's submission of the insurance information was not the basis for Vectren contacting the customer to request complete insurance information. The insurance information originally supplied was incomplete in that the insurance documentation provided by Morton Solar did not show the liability coverage amount. Vectren contacted the customer to obtain a complete insurance form which contained liability coverage amounts. The most recent insurance information provided is under a name different than the customer, so Vectren continues working to address these insurance issues.

Request No. 3-4: If your responses to any of the requests for admission Nos. 3-1(a) through 3-1(d) are anything other than an unqualified admission, please explain your response.

Response:

a. Vectren did not reject the interconnection agreement tendered by Martha Crosley. Vectren was adhering to the requirements of 170 IAC 4-4.3-6(k)(2) by forwarding a copy of an interconnection agreement executed by Vectren for the customer to return 10 calendar days before operation of the customer-owned generator. This method also ensures that Vectren's customer is the party executing the agreement and has an opportunity to understand the commitments the customer is assuming by executing the agreement. In the past, Vectren has received a signed agreement before signing itself and that practice led to premature interconnections by Morton Solar and to some confusion as to whether a fully executed agreement was returned to the customer. This presents numerous potential safety issues. Please also see Vectren's response to Request No. 3-5.

b. Morton Solar's submission of the interconnection agreement was not Vectren's basis for executing an interconnection agreement and sending it to the customer for review. Vectren was adhering to the Commission's interconnection rules in 170 IAC 4-4.3-1 et seq. For example, a Level 1 interconnection review requires Vectren to execute and send to the customer a Level 1 interconnection agreement within ten (10) business days of sending notice that the application is complete. 170 IAC 4-4.3-6(k)(2). The customer is required to return the executed interconnection agreement ten (10) business days before starting operation of the customer-generator facility. 170 (AC 4-4.3-6(l)(2). Please also see Vectren's response to Request No. 3-5.

c. N/A

d. Morton Solar's submission of the insurance information was not the basis for Vectren contacting the customer to request complete insurance information. Morton attempted to submit the insurance information electronically on August 6, 2013, but the information was never received by Vectren due to information technology issues, so Vectren immediately contacted the customer on the same day to request the information. A hard copy was ultimately provided to Vectren by the customer on August 20, 2013.

Request No. 3-5: Do any of the facts alleged in Data Requests 3-1 through 3-4 reflect any changes in Vectren policy, implemented since IURC Cause No. 44344 was initiated, regarding interconnection applications? If so, please explain those policy changes and the reasons for them.

Response: Vectren is specifically sending interconnection agreements it has executed to customers for their execution and return before the customer-generator facility begins operation to ensure compliance with 170 IAC 4-4.3-6(j) and (k) and -7(q)(and (r). This practice has a number of benefits. First, it complies with the Commission's rules governing customer-generator facilities. 170 IAC 4-4.3-1 et seq. Second, this helps resolve concerns raised by Morton Solar about the return of executed interconnection agreements to customers. This practice will allow customers to make a copy of the fully executed agreement before returning it to Vectren, and will also ensure that Vectren receives an executed interconnection agreement because the customers must return it as a pre-requisite for operating the interconnection system. Third, this practice will help ensure that customer-generator facilities are not interconnected before the interconnection process is complete. Interconnection prior to that endangers the lives of Vectren's employees that may be working on infrastructure without knowledge of interconnected facilities and can lead to difficulties identifying power quality and other engineering issues. The Commission's rules are written to ensure that the interconnection is vetted early in the process, before the generator facility constructed, so potential problems can potentially be addressed in the facility design.

Request No. 3-6: Please provide copies of any documents setting forth changes to Vectren's policies or procedures for handling interconnection agreements for customer generation that have been proposed or implemented since IURC Cause No. 44344 was initiated.

Response: Please see the attached Exhibit DR 3-6, which is a letter from Vectren to Morton Solar's counsel on September 11, 2013 explaining certain changes in Vectren practice designed to make the process more efficient and clear.

Vectren Corporation
One Vectren Square
P.O. Box 209
Evansville, IN 47702

September 11, 2013

Via U.S. Mail and electronic mail

J. David Agnew, Esq.
Lorch Naville Ward, LLC
506 State Street
P.O. Box 1343
New Albany, IN 47151-1343
DAgnew@lnwlegal.com

Re: Morton Solar, LLC

Mr. Agnew:

I appreciate the time you spent discussing our concerns about the tone and nature of recent communications involving Mr. Morton and certain employees of Vectren Energy Delivery, Inc. ("Vectren"). Regardless of the pending complaint filed by Mr. Morton with the Indiana Utility Regulatory Commission ("Commission"), Vectren's employees and Morton Solar's representatives will need to continue working collaboratively to ensure a smooth interconnection process for customers that want to install customer-generator facilities.

I want to reiterate that Vectren is not refusing to accept documents from Morton Solar. Morton Solar is free to continue to submit interconnection applications on behalf of Vectren customers and to otherwise assist customers in navigating the interconnection process. While Vectren has always worked cooperatively with its customers, in recognition that in the past interconnection applications have been submitted along with a copy of the interconnection agreement already executed by the customer even though the review process has not been completed, Vectren's process will be as follows: Vectren will forward the customer a copy of the interconnection agreement executed by Vectren after the interconnection is approved. This approach will be followed in all instances going forward for three reasons. First, this is the procedure set forth in the Commission's rules governing customer-generator facilities. 170 IAC 4-4.3-1 et seq. For example, a Level 1 interconnection review requires Vectren to execute and send to the customer a Level 1 interconnection agreement within ten (10) business days of sending notice that the application is complete. 170 IAC 4-4.3-6(k)(2). The customer is required to return the executed interconnection agreement ten (10) business days before starting operation of the customer-generator facility. 170 (AC 4-4.3-6(l)(2).

Second, this change will resolve concerns raised by Morton Solar about Vectren's return of executed interconnection agreements to customers. Once customers execute the interconnection agreement that Vectren has already executed, they will be able to make a copy of the fully executed agreement before returning the agreement to Vectren. This arrangement will also ensure that Vectren receives an executed interconnection agreement because the customers must return it as a pre-requisite for operating its system.

Third, adherence to this process will help address misunderstandings about interconnecting generation facilities to Vectren's system. On numerous occasions, Vectren has discovered customer-generator facilities already interconnected to its system before the interconnection process is complete. This endangers the lives of Vectren's employees that may be working on infrastructure without knowledge of an interconnected generation facility and can lead to difficulties identifying power quality and other potential issues that can result from customers-generator facilities. The Commission's interconnection rules are written with the assumption that the interconnection of customer-generator facilities will work in the same fashion as other generator interconnections—the interconnection is vetted early in the process, before the generator facility is constructed, so potential problems can potentially be addressed in the generator facility design.

I wanted to reiterate that Vectren is not singling-out Morton Solar. This procedure will be applied uniformly to all customers and their contractors.

Apart from explaining this approach to the processing of interconnection applications, as noted during our conversation, we do not want a hostile relationship with Mr. Morton and would request that civility be adhered to in all communications with our employees. Vectren again extends the offer made during the call to further discuss any perception of unfairness. Jason or I are available for further discussions.

Sincerely,

/s/ Joshua A. Claybourn

Joshua Claybourn

Cc: Robert Heidorn, Esq.
Jason Stephenson, Esq.

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE APPEAL TO THE INDIANA UTILITY REGULATORY COMMISSION FROM THE CONSUMER AFFAIRS DIVISION OF THE RULING ON COMPLAINT BY MORTON SOLAR & WIND, LLC AGAINST VECTREN UTILITY HOLDINGS, INC. d/b/a VECTREN ENERGY DELIVERY OF INDIANA – SOUTH	)	**CAUSE NO. 44344**

RESPONSE TO VECTREN ENERGY'S 1ST SET OF DATA REQUESTS TO MORTON SOLAR & WIND, LLC

Morton Solar & Wind, LLC ("the Complainant"), by and through its legal counsel, responds to the first set of data requests from Vectren Energy as follows:

NOTES AND GENERAL OBJECTIONS RE ALL DOCUMENT REQUESTS

1. The responses provided to this discovery request have been prepared pursuant to a reasonable and diligent investigation and search for the requested information. The Complainant is a limited liability company, with limited administrative and support staff who are responsible for its administration and day-to-day operations. The limited number of administrative and support staff limits its ability to locate quickly "all" documents relevant to particular issues.

Accordingly, the Complainant cannot and does not represent that responses to the Requests provide every possible piece of information that exists in any form; rather, the responses reflect the information obtained up to this date by it and its consultants pursuant to a reasonable and diligent search of the documents and records available to these representatives. In this posture, the Complainant has made a diligent effort to locate and identify all documents responsive to the Requests directed to it within the applicable discovery rules. To the extent that the Requests purport to require more than this reasonable and diligent search and investigation, the Complainant objects on the grounds that such a search would represent an undue burden and/or unreasonable expense.

2. The Complainant objects to the Requests to the extent that they seek documents or information which, in whole or in part, request, offer, represent, or relate to counsel's legal advice, legal conclusions or mental impressions about the case, including counsel's legal theories and expectations or preparations for litigation, since these are protected by attorney-client and attorney work-product privileges, and are not discoverable. The Complainant objects to the Requests to the extent the term "all documents" includes items that contain matter privileged under the attorney-client and attorney work-product privileges. However, subject to mutual agreement with counsel for Vectren Energy, counsel for the Complainant will, on a reciprocal basis, prepare and provide a privilege log.

3. The Complainant objects to the Requests to the extent they exceed the scope and methods of discovery allowed under Trial Rule 26(B). The Complainant further reserves its right under Trial Rule 26(B) to seek compensation for expert fees and costs associated with complying with the Requests.

4. The Complainant objects to the Requests as unreasonably cumulative or duplicative to the extent the information is obtainable from some other source that is more convenient, less burdensome, or less expensive including but not limited to testimony previously filed or to be filed in this cause.

5. The Complainant objects to the Requests to the extent they are unduly burdensome, oppressive, and calculated to take the Complainant, and its staff, away from normal work activities, require them to spend hours reviewing organizational records in order to answer said Requests, and require them to expend significant resources to provide complete and accurate answers to Ventren Energy's discovery requests to generate material that, even if relevant, is of marginal value and can be obtained more easily through other means.

6. The Complainant objects to the Requests to the extent they seek documents and/or information which are neither relevant nor material to the subject matter of this litigation, nor reasonably calculated to lead to the discovery of relevant or admissible evidence, especially, but not exclusively, because they seek information outside the scope of this proceeding.

7. The Complainant objects to the Requests to the extent that they seek analysis, calculations, or compilations which have not already been performed and which the Complainant objects to performing.

8. The Complainant objects to the Requests to the extent that they are vague and ambiguous and provide no reasonable basis from which the Complainant can determine what information is being sought.

9. The Complainant objects to the Requests to the extent they request or direct supplementation except to the extent required by Ind. Tr. R. 26(E).

10. The Complainant objects to the Requests for the additional, specific individual grounds identified immediately before each Response.

Respectfully submitted,

/s/ J. David Agnew

J. David Agnew
Attorney for Complainant
LORCH NAVILLE WARD LLC
502 State Street
New Albany, IN 47150
Phone: (812) 949-1000
Fax: (812) 949-3773
dagnew@lnwlegal.com

Pursuant to 170 IAC 1-1.1-16 and the agreements regarding discovery at the Prehearing Conference in this Cause, Southern Indiana Gas and Electric Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren Energy" or "Respondent") hereby requests Morton Solar & Wind LLC ("Morton Solar") respond to each of the following discovery requests.

Vectren Energy requests that responses be transmitted via email, when possible. Production shall be made to the following Vectren Energy counsel, as soon as practicable and, in no event later than the discovery deadline agreed to at the Prehearing Conference in this proceeding:

Robert E. Heidorn, Atty. No. 14264-49
VECTREN CORPORATION
One Vectren Square
211 N.W. Riverside Drive
Evansville, IN 47708
E-Mail: rheidorn@vectren.com

and

Joshua A. Claybourn, # 26305-49
Vectren Corporation
One Vectren Square
211 N.W. Riverside Drive
Evansville, Indiana 47708
E-Mail: jclaybourn@vectren.com

and

P. Jason Stephenson, Atty. No. 21839-49
BARNES & THORNBURG LLP
11 South Meridian Street
Indianapolis, IN 46204
E-Mail: Jason.stephenson@btlaw.com

DEFINITIONS AND INSTRUCTIONS

1. "Communication" means the transmittal in any manner or by any method of information (in the form of facts, ideas, inquiries, or otherwise).

2. "Complaint" shall mean the Verified Complaint and Appeal From Consumer Affairs Decision filed by Morton Solar to initiate this proceeding.

3. "Documents" means and includes any and all materials within the scope of Ind. Trial Rule 34(A)(1) and shall be construed broadly to encompass, without limitation, all handwritten, typed, printed or otherwise visually or orally reproduced materials, whether copies or originals, and includes drafts and translations of any document, data sheets, discs, diskettes, data contained in any computer, emails, spreadsheets, faxes, printed material, information that can be retrieved from any computer, and any information produced or reproduced mechanically, magnetically, electrically, electronically, photographically, or by any other means.

4. "Identify" means:

   a. As to an individual, state the individual's name, business address, present occupation, present organizational title, and, where relevant, past occupation and organizational title;

   b. As to an entity other than an individual, state its full name, the address of its principal place of business, and its state of incorporation or organization;

   c. As to a document, state its author or maker, date, general subject matter, addressees, and recipients, if any;

d. As to a meeting or oral communication, state the date and place of such meeting or oral communication, the purpose and subjects of such meeting or oral communication, every person participating in or present at such meeting or oral communication, and every document referring or relating to such meeting or oral communication;

e. As to a fact, state the subject and substance of the fact, each meeting, communication or other event, which constitutes the fact, and each document referring or relating to the fact.

5. "Morton Solar" means Morton Solar & Wind, LLC and all of its agents, representatives, consultants, and employees.

6. These requests shall be deemed to be continuing. Any information or document responsive to these requests which Morton Solar acquires subsequent to the initial response shall be provided within a reasonable time after such information or document is acquired.

7. This set of data request is subject to supplementation and amendment as required by Ind. Trail Rule 26(E).

DATA REQUESTS

<u>Request No. 1-16</u> Reference numerical paragraph 12 in the Complaint. Please describe all requests made by Morton Solar for Vectren to return executed interconnection agreement including the date of the request, the type or form of communication made with Vectren Energy, the identify of employee or agent of Morton Solar making the request and the Vectren Energy employee or agent the request was made to. Please provide copies of all documents constituting such requests.

<u>Response:</u> **See attachments 1-16. Brad Morton sent several emails requesting the executed interconnection agreements.**

Exhibit SCS-2

Jennifer Washburn <jwashburn@citact.org>

FW: Vectren's First Set of Data Requests to Morton Solar, Our file #39762

J. David Agnew <DAgnew@lnwlegal.com> Tue, Aug 6, 2013 at 3:05 PM
To: Jennifer Washburn <jwashburn@citact.org>

2 of 3.

From: Cindi Smithson
Sent: Monday, August 05, 2013 11:57 AM
To: rheidorn@vectren.com; jclaybourn@vectren.com; Jason.stephenson@btlaw.com
Cc: rhelmen@oucc.IN.gov; jwashbur@citact.org; J. David Agnew
Subject: Vectren's First Set of Data Requests to Morton Solar, Our file #39762

Additional documents attached.

Cindi Smithson

Legal Assistant

LORCH & NAVILLE, LLC

506 State Street, P.O. Box 1343

New Albany, IN 47151-1343

Phone (812) 949-1000

Fax (812) 949-3773

e-mail: csmithson@lnwlegal.com

www.LNWLegal.com

of any attorney-client work product or other applicable privilege. Thank you.

---------- Forwarded message ----------
From: "Van Bibber, Brad" <bjvanbibber@Vectren.com>
To: Brad Morton <bmorton@mortonenergy.com>
Cc:
Date: Thu, 17 Mar 2011 15:53:37 -0400
Subject: RE: Davidson's

OK, I will have to get that one tomorrow, I will not be back in the office until then.

Brad

From: Brad Morton [mailto:bmorton@mortonenergy.com]
Sent: Thursday, March 17, 2011 12:15 PM
To: Van Bibber, Brad; Dougan, Ann-Marie E.
Subject: RE: Davidson's

Thanks Brad.

We will also need Andy Davidson's as well.

Best Regards,

Brad Morton

From: Van Bibber, Brad [mailto:bjvanbibber@Vectren.com]
Sent: Thursday, March 17, 2011 9:24 AM
To: Dougan, Ann-Marie E.; bmorton@mortonenergy.com
Subject: RE: Davidson's

Brad,

Here is a copy of the interconnection agreement for the Davidsons. Let me know if you need anything else.

Thanks,

Brad

From: Dougan, Ann-Marie E.
Sent: Thursday, March 17, 2011 8:03 AM
To: 'bmorton@mortonenergy.com'; Van Bibber, Brad
Subject: Re: Davidson's

Brad,

Can you provide this to Brad Morton?

Thanks
Ann-Marie

From: Brad Morton <bmorton@mortonenergy.com>
To: Dougan, Ann-Marie E.
Sent: Thu Mar 17 07:57:48 2011
Subject: Davidson's

Hi Ann-Marie,

Could you send me the signed net-metering contract's for Nick & Andy Davidson?

They need this to sell their Solar Renewable Energy Credits.

Thanks,

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

(812)402-0900

Fax (812)402-9695

MORTON SOLAR & WIND

NABCEP Certified

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---------- Forwarded message ----------
From: Brad Morton <bmorton@mortonsolar.com>
To: "Dougan, Ann-Marie E." <ADougan@Vectren.com>
Cc:
Date: Tue, 17 May 2011 12:46:06 -0400
Subject: RE: net meter 901 New Harmony Rd
Thanks!

Brad Morton
Morton Solar & Wind, LLC
Evansville, Indiana
(812)402-0900
Fax (812)402-9695

NABCEP Certified

-----Original Message-----
From: Dougan, Ann-Marie E. [mailto:ADougan@Vectren.com]
Sent: Tuesday, May 17, 2011 10:48 AM
To: Brad Morton
Subject: FW: net meter 901 New Harmony Rd

Brad,

Please find attached the signed net meter agreement for Tony Kohut.

Thanks,
Ann-Marie

-----Original Message-----
From: GlobalScan 2.0
Sent: Tuesday, May 17, 2011 10:46 AM

To: Dougan, Ann-Marie E.
Subject: net meter 901 New Harmony Rd

GlobalScan document sent from .

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---------- Forwarded message ----------
From: "Van Bibber, Brad" <bjvanbibber@Vectren.com>
To: Brad Morton <bmorton@mortonsolar.com>
Cc:
Date: Thu, 17 Jan 2013 14:38:57 -0500
Subject: RE: Net-Metering Agreements signed from Vectren

I will track these down and get copies to you.

Brad

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Thursday, January 17, 2013 1:17 PM
To: Van Bibber, Brad
Cc: Dougan, Ann-Marie E.
Subject: Net-Metering Agreements signed from Vectren

Brad,

I need to have the net-metering agreements signed from Vectren.

Can you get the attached net-metering agreements with signature from appropriate official?

The following are attached:

1) Norm Miller

2) Allen Stute

Thanks and best regards,

Brad Morton

Morton Solar & Wind, LLC

(812)402-0900

(270)799-8978

Fax (812)402-9695

NABCEP Certified

---------- Forwarded message ----------
From: "Dougan, Ann-Marie E." <ADougan@Vectren.com>
To: "bmorton@mortonsolar.com" <bmorton@mortonsolar.com>
Cc:
Date: Tue, 10 May 2011 13:19:40 -0400
Subject: Re: Net-Metering Application - Tony Kohut

Yes and I will contact Zac about the meter.
Thanks Brad.

From: Brad Morton <bmorton@mortonsolar.com>
To: Dougan, Ann-Marie E.
Sent: Tue May 10 12:18:49 2011
Subject: RE: Net-Metering Application - Tony Kohut

Ann Marie,

Here is the signed agreement.

Could you send back to me with Vectren’s signature?

I need for our records.

Thanks,

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

(812)402-0900

Fax (812)402-9695

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From: Dougan, Ann-Marie E. [mailto:ADougan@Vectren.com]
Sent: Tuesday, May 10, 2011 8:06 AM
To: Brad Morton
Subject: RE: Net-Metering Application - Tony Kohut

Thanks Brad. I don't seem to have the agreement either. Can execute and scan back to me?

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Monday, May 09, 2011 7:07 PM
To: Dougan, Ann-Marie E.
Subject: RE: Net-Metering Application - Tony Kohut

Ann-Marie,

Here is the insurance for Tony Kohut.

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

(812)402-0900

Fax (812)402-9695

NABCEP Certified

From: Dougan, Ann-Marie E. [mailto:ADougan@Vectren.com]
Sent: Tuesday, May 03, 2011 7:31 PM
To: Brad Morton
Subject: RE: Net-Metering Application - Tony Kohut

Brad,

Would you please have the customer send me their insurance documentation and agreement.

Thanks,

Ann-Marie

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Monday, April 04, 2011 3:22 PM
To: Dougan, Ann-Marie E.
Subject: Net-Metering Application - Tony Kohut

Ann-Marie,

Attached is a net-metering application for Tony Kohut.

The system is installed and ready for commissioning.

Let me know when Vectren would like to schedule inspection.

Thanks and best regards,

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

(812)402-0900

Fax (812)402-9695

MORTON SOLAR & WIND

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---------- Forwarded message ----------
From: Brad Morton <bmorton@mortonenergy.com>
To: "klitkenhus@ms1.nspencer.k12.in.us" <klitkenhus@ms1.nspencer.k12.in.us>
Cc:
Date: Mon, 13 Dec 2010 00:23:42 -0500
Subject: Solar Renewable Energy Credits

Kim,

I have some good news for you.

Solar energy system owners in Indiana are now eligible to sell their Solar Renewable Energy Credits (SREC's) to other states.

What this means is that the Chrisney Library can take an upfront payment for the next 10 years of credits, or can take quarterly payments depending on the amount of energy produced by your system.

For your system, the upfront payment would be $10,235 and this would be for 10 years worth of credits.

If the quarterly payments are chosen, the amount would be $200 per MWh produced and a 5 year contract is required.

Last year your system produced approx. 14,000 Kwh or 14 Mwh. So, your payments would have been $2800 for the year.

How to get started?

With your approval, I will start the qualification process.

We are now a Platinum Provider with Sol Systems out of Washington DC who is a broker for SREC's.

I believe that you will get paid for the energy you have already produced as well.

Let me know…

Best Regards,

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

(812)402-0900

---

5 attachments

Exhibit SCS-2

MORTON SOLAR & WIND **image001.jpg**
5K

MORTON SOLAR & WIND **image001.jpg**
5K

Sol Annuity_1 sheet.pdf
312K

Sol Upfront_1 sheet.pdf
286K

Sol Pricing November 2010.pdf
113K

Exhibit SCS-2

Jennifer Washburn <jwashburn@citact.org>

FW: Vectren's First Set of Data Requests to Morton Solar, Our file #39762

J. David Agnew <DAgnew@lnwlegal.com> Tue, Aug 6, 2013 at 3:04 PM
To: Jennifer Washburn <jwashburn@citact.org>

Jennifer,

It looks like Cindi sent these out with a typo in your email address. That explains why you didn't receive them.

From: Cindi Smithson
Sent: Monday, August 05, 2013 11:53 AM
To: rheidorn@vectren.com; jclaybourn@vectren.com; Jason.stephenson@btlaw.com
Cc: rhelmen@oucc.IN.gov; jwashbur@citact.org; J. David Agnew
Subject: Vectren's First Set of Data Requests to Morton Solar, Our file #39762

Ladies and Gentlemen:

Please find attached Morton Solar's responses to Vectren's First Set of Data Requests. I have also attached a Confidentiality Agreement, in both Microsoft Word and pdf. format. We are attaching certain documents specific to many of the responses; however, other documents will not be sent until a signed Confidentiality Agreement is received in our office. Due to the restrictions of our computer system, I will be forwarding some documents in following emails.

Should you have any questions regarding this, please feel free to contact our office. Thank you.

Very truly yours,

Cindi L. Smithson

Legal Assistant to J. David Agnew

Cindi Smithson

Legal Assistant

LORCH & NAVILLE, LLC

506 State Street, P.O. Box 1343

New Albany, IN 47151-1343

Phone (812) 949-1000

Fax (812) 949-3773

e-mail: csmithson@lnwlegal.com

www.LNWLegal.com

---------- Forwarded message ----------
From: Brad Morton <bmorton@mortonsolar.com>
To: "ADougan@Vectren.com" <ADougan@Vectren.com>
Cc:
Date: Thu, 7 Jul 2011 18:55:11 -0400
Subject: Banner & Weiss

Ann-Marie,

Could you give me an update on Chanda Banner & Gary Weiss net-metering agreements?

Thanks,

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

(812)402-0900

Fax (812)402-9695

NABCEP Certified

---------- Forwarded message ----------
From: "Dougan, Ann-Marie E." <ADougan@Vectren.com>
To: Brad Morton <bmorton@mortonenergy.com>
Cc:
Date: Tue, 24 Nov 2009 18:08:00 -0500
Subject: FW: Andy Davidson Net-Metering Agreement - Signed

Thanks Brad. They will be out tomorrow to set the meter.

Thanks for your help.

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Tuesday, November 24, 2009 5:06 PM
To: Dougan, Ann-Marie E.
Subject: Andy Davidson Net-Metering Agreement - Signed

Ann-Marie,

Attached is a signed Net-Metering agreement from Andy Davidson along with the diagram.

Let me know if you need anything else.

Thanks,

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

Ph: 812-402-0900

Cell: 812-453-1924

Fax: 812-402-9695

MORTON
SOLAR & WIND

---------- Forwarded message ----------
From: "Dougan, Ann-Marie E." <ADougan@Vectren.com>
To: Brad Morton <bmorton@mortonsolar.com>
Cc:
Date: Tue, 30 Mar 2010 15:45:14 -0400
Subject: RE: Application for Net-Metering - Don Jost

Thanks Brad.

Ann-Marie Dougan

Senior Field Sales Representative

VECTREN

1 N. Main Street

P.O. Box 209

Evansville, IN 47702-0209

812-491-4604 phone

adougan@vectren.com

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Tuesday, March 30, 2010 10:07 AM
To: Dougan, Ann-Marie E.
Subject: RE: Application for Net-Metering - Don Jost

Ann-Marie,

I believe his cell phone number is: **812-499-2166.**

His system will be installed next week, so it's no hurry.

He is almost right across the street from the Haubstadt Elementary School.

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

Ph: 812-402-0900

Cell: 812-453-1924

Fax: 812-402-9695

From: Dougan, Ann-Marie E. [mailto:ADougan@Vectren.com]
Sent: Tuesday, March 30, 2010 9:35 AM
To: Brad Morton
Subject: FW: Application for Net-Metering - Don Jost

Brad,

We cannot locate this address for Mr. Jost to put in the meter request. I tried to call him at the number on the application; however, did not get an answer or an option to leave a message. I will need to secure the insurance requirements from him as well as the agreement, do you have another number or email for him?

Thanks,

Ann-Marie Dougan

Senior Field Sales Representative

VECTREN

1 N. Main Street

P.O. Box 209

Evansville, IN 47702-0209

812-491-4604 phone

adougan@vectren.com

From: Frederick, Fred J.
Sent: Tuesday, March 30, 2010 9:21 AM
To: Dougan, Ann-Marie E.
Subject: RE: Application for Net-Metering - Don Jost

Approved

From: Dougan, Ann-Marie E.
Sent: Tuesday, March 30, 2010 8:52 AM
To: Lewis, Regina F.
Cc: Frederick, Fred J.
Subject: FW: Application for Net-Metering - Don Jost

Regina,

Would you please enter this Net meter in Maximo?

Thanks,

Ann-Marie Dougan

Senior Field Sales Representative

VECTREN

1 N. Main Street

P.O. Box 209

Evansville, IN 47702-0209

812-491-4604 phone

adougan@vectren.com

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Sunday, March 28, 2010 2:31 PM
To: Dougan, Ann-Marie E.
Subject: Application for Net-Metering - Don Jost

Ann-Marie,

Attached is Net-Metering application for Don Jost in Haubstadt, Indiana.

Let me know if you need further information.

Thanks,

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

Ph: 812-402-0900

Cell: 812-453-1924

Fax: 812-402-9695

MORTON SOLAR & WIND

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No virus found in this incoming message. Checked by AVG - www.avg.com Version: 9.0.791 / Virus Database: 271.1.1/2780 - Release Date: 03/30/10 13:32:00

---------- Forwarded message ----------
From: "Van Bibber, Brad" <bjvanbibber@Vectren.com>
To: Brad Morton <bmorton@mortonsolar.com>
Cc:
Date: Wed, 8 Jun 2011 12:26:23 -0400
Subject: RE: Davidson's

Brad,

Sorry for any delay. But here you go.

Thanks,

Brad Van Bibber

Vectren Energy

Account Manager

812-491-5010

bjvanbibber@vectren.com

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Wednesday, June 08, 2011 9:55 AM
To: Van Bibber, Brad
Subject: RE: Davidson's

Brad,

I still need the signed net-metering agreement for Andy Davidson.

Can you email this to me?

Thanks,

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

(812)402-0900

Fax (812)402-9695

MORTON SOLAR & WIND

NABCEP Certified

From: Van Bibber, Brad [mailto:bjvanbibber@Vectren.com]
Sent: Thursday, March 17, 2011 2:54 PM
To: Brad Morton
Subject: RE: Davidson's

OK, I will have to get that one tomorrow, I will not be back in the office until then.

Brad

From: Brad Morton [mailto:bmorton@mortonenergy.com]
Sent: Thursday, March 17, 2011 12:15 PM
To: Van Bibber, Brad; Dougan, Ann-Marie E.
Subject: RE: Davidson's

Thanks Brad.

We will also need Andy Davidson's as well.

Best Regards,

Brad Morton

From: Van Bibber, Brad [mailto:bjvanbibber@Vectren.com]
Sent: Thursday, March 17, 2011 9:24 AM
To: Dougan, Ann-Marie E.; bmorton@mortonenergy.com
Subject: RE: Davidson's

Brad,

Here is a copy of the interconnection agreement for the Davidsons. Let me know if you need anything else.

Thanks,

Brad

From: Dougan, Ann-Marie E.
Sent: Thursday, March 17, 2011 8:03 AM
To: 'bmorton@mortonenergy.com'; Van Bibber, Brad
Subject: Re: Davidson's

Brad,

Can you provide this to Brad Morton?

Thanks
Ann-Marie

From: Brad Morton <bmorton@mortonenergy.com>
To: Dougan, Ann-Marie E.
Sent: Thu Mar 17 07:57:48 2011
Subject: Davidson's

Hi Ann-Marie,

Could you send me the signed net-metering contract's for Nick & Andy Davidson?

They need this to sell their Solar Renewable Energy Credits.

Thanks,

Brad Morton

Morton Solar & Wind, LLC

Evansville, Indiana

(812)402-0900

Fax (812)402-9695

MORTON SOLAR & WIND

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---------- Forwarded message ----------
From: "Parker, Jeremiah Q." <jqparker@Vectren.com>
To: Brad Morton <bmorton@mortonsolar.com>
Cc: "Dougan, Ann-Marie E." <ADougan@Vectren.com>
Date: Tue, 6 Nov 2012 09:44:52 -0500
Subject: RE: Denise Vaal Solar Project

Brad,

I have informed Jason Williams with the Vectren Electric Meter Dept. of this inspection completion, and to proceed with the net meter installation.

Thanks,

Jeremiah Q. Parker

Electric Distribution Engineer

Vectren Energy Delivery

(812) 491-4754 - Office

(812) 491-4504 - Fax

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Monday, November 05, 2012 7:43 PM
To: Parker, Jeremiah Q.
Subject: Denise Vaal Solar Project

Jeremiah,

The system at Denise Vaal, Dale, Indiana has been inspected by Spencer Co. Building Commission.

Brad Morton

Morton Solar & Wind, LLC

(812)402-0900

(270)799-8978

Fax (812)402-9695

MORTON SOLAR & WIND

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---------- Forwarded message ----------
From: Brad Morton <bmorton@mortonsolar.com>
To: "Dougan, Ann-Marie E." <ADougan@Vectren.com>
Cc:
Date: Tue, 17 May 2011 12:46:06 -0400
Subject: RE: net meter 901 New Harmony Rd
Thanks!

Brad Morton
Morton Solar & Wind, LLC
Evansville, Indiana
(812)402-0900
Fax (812)402-9695

NABCEP Certified

-----Original Message-----
From: Dougan, Ann-Marie E. [mailto:ADougan@Vectren.com]
Sent: Tuesday, May 17, 2011 10:48 AM
To: Brad Morton
Subject: FW: net meter 901 New Harmony Rd

Brad,

Please find attached the signed net meter agreement for Tony Kohut.

Thanks,
Ann-Marie

-----Original Message-----
From: GlobalScan 2.0
Sent: Tuesday, May 17, 2011 10:46 AM
To: Dougan, Ann-Marie E.
Subject: net meter 901 New Harmony Rd

GlobalScan document sent from .

---------- Forwarded message ----------
From: "Dougan, Ann-Marie E." <ADougan@Vectren.com>
To: Brad Morton <bmorton@mortonsolar.com>
Cc:
Date: Thu, 14 Jun 2012 16:14:24 -0400
Subject: RE: Net Metering for 3221 N. Eleventh Ave

I will check on it. Thanks Brad.

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Thursday, June 14, 2012 2:53 PM
To: Dougan, Ann-Marie E.
Subject: FW: Net Metering for 3221 N. Eleventh Ave

Hi Ann-Marie,

I had to meet CAPE at this home today for a follow-up on the project and we noticed that the meter had not been changed to a new digital model.

Not sure if it is a problem or not but just wanted to let you know.

Brad Morton

Morton Solar & Wind, LLC

(812)402-0900

(270)799-8978

Fax (812)402-9695

NABCEP Certified

From: Brad Morton [mailto:bmorton@mortonsolar.com]
Sent: Wednesday, January 11, 2012 2:50 PM
To: ADougan@Vectren.com
Subject: Net Metering for 3221 N. Eleventh Ave

Ann-Marie,

Here is net-metering application for Robert Martin, 3221 N. Eleventh Ave.

Best regards,

Brad Morton

Morton Solar & Wind, LLC

(812)402-0900

(270)799-8978

Fax (812)402-9695

NABCEP Certified

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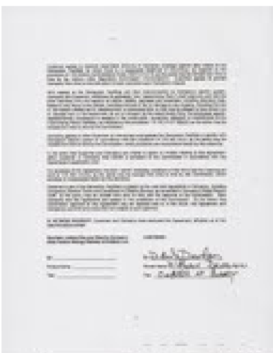
12 attachments

image001.jpg
5K

Vectren Net-Metering P1.JPG
677K



Vectren Net-Metering P2 Signed.JPG
663K

image001.jpg
5K

image001.jpg
5K

Responses to First Set of Data Requests by Vectren Energy.pdf
43K

Confidentiality Agreement.doc
35K

Confidentiality Agreement - unsigned.pdf
28K

Response 1-7 VECTREN Clients 072613.xls
37K

Vectren Customers Response 1-13.xlsx
13K

P175 Solar Diagram.pdf
57K

Andy Davidson Connection Agreement.pdf
1623K

Exhibit SCS-3

Model Interconnection Procedures, Interstate Renewable Energy Council, 2013 Edition, available at: http://www.irecusa.org/wp-content/uploads/2013-IREC-Interconnection-Model-Procedures.pdf.

Exhibit SCS-3

Model Interconnection Procedures

2013 Edition

Interstate Renewable Energy Council, Inc.

INTRODUCTION

IREC first developed model interconnection procedures in 2005 in an effort to capture emerging best practices in this vital area. Since that time, IREC has been an active participant in dozens of state utility commission rulemakings that have focused on the development of interconnection procedures. As states have adopted such procedures, IREC has witnessed the effects, both good and bad, on renewable energy market development within those states. As a result of this experience, and the experience gained by developers and utilities since IREC's model procedures were last updated in 2009, IREC has identified several important evolutions in best practices that IREC has synthesized into these updated model interconnection procedures.

Among the important advances incorporated into these model procedures are: integrating a Pre-Application Report; updating the construction-related screen in Levels 1, 2 and 3; including more sophisticated sizing criteria for Level 2, which vary according to the voltage of the line at the proposed Point of Interconnection; improving the Supplemental Review Process by increasing its clarity and transparency; adding an Applicant Options Meeting prior to entering Level 4; eliminating the Feasibility Study; updating Application fees; and explicitly allowing for electronic signatures. For a discussion of the rationale for adopting these changes, please refer to *Updating Small Generator Interconnection Procedures for New Market Conditions*, issued by the National Renewable Energy Laboratory and available at http://www.nrel.gov/docs/fy13osti/56790.pdf. These updated procedures also include footnotes that explain key provisions and provide information on alternatives that are being practiced in some states.

For additional information on best practices in interconnection procedures and net metering rules, please refer to *Freeing the Grid,* http://freeingthegrid.org, which is updated annually by the Network for New Energy Choices in collaboration with The Vote Solar Initiative, the North Carolina Solar Center and IREC. *Freeing the Grid* grades interconnection procedures of all fifty states based on sixteen criteria, including: facility size limitations, timelines, screening procedures to rapidly approve standard facilities, use of standard form agreements and insurance provisions. With its clear explanation of the major interconnection issues and discussion of how states have addressed those issues, *Freeing the Grid* is an invaluable resource for utility commission staff facing the daunting task of creating or revising state procedures.

IREC welcomes the opportunity to work with state utility commissions and individual utilities to develop interconnection procedures; please contact IREC at info@irecusa.org with inquiries. This model is available at http://www.irecusa.org/wp-content/uploads/2013-IREC-Interconnection-Model-Procedures.pdf.

TABLE OF CONTENTS

I. OVERVIEW

A. Scope

These Interconnection Procedures are applicable for all state-jurisdictional interconnections of Generating Facilities.[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[2] and/or an Applicant Options Meeting prior to entering Level 4. The Utility will usually process the relevant Generating Facilities' Applications in the order they were received.[3] 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 and may be considered by the Utility at its discretion. If an Applicant is denied approval for interconnection under one level and reapplies under another

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[1] Depending on state law, individual utility procedures may govern interconnections, particularly for municipal and cooperative utilities and public utility districts. These model 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 line interconnections and on rare occasions, for distribution line interconnections.

[2] The Supplemental Review process described in these Interconnection Procedures is distinct from the FERC's Small Generator Interconnection Procedures (SGIP) Supplemental Review process, which has a similar analog in several states, but it builds upon the FERC process, adding detail and timelines. In the FERC SGIP, as in these Interconnection Procedures (§ 2.3.2), when an Applicant fails the initial Fast Track screens (similar to Levels 1 through 3), the Applicant is given an option to proceed to Supplemental Review if the utility believes further analysis might identify options for interconnection that do not require full study. The specific detail on what will be evaluated during the Supplemental Review process is not identified, however, nor is the time within which the process should be completed. For more detail on the Supplemental Review process included in these Interconnection Procedures, see Section III.D.

[3] In most cases, approval of one proposed Generating Facility will not determine whether other proposed Generating Facilities will pass the technical screens. It would be very unusual for an effect to be felt beyond an individual circuit or network. In these cases, it may be appropriate to study these applications as a group.

level within ten (10) Business Days of receipt of that denial, the date of Utility receipt of the initial Application shall be used for purposes of the order of review. No automatic extension of Utility review periods are allowed as delays can impact later proposed Generating Facilities. However, the Utility and an Applicant may mutually agree to a delay and the Utility may request that the Commission provide an extension for review of one or more Applications.

The four interconnection review paths are:

a. Level 1—For inverter-based Generating Facilities that have a Generating Capacity of 25 kilowatts (kW)[4] or less.

b. Level 2—For Generating Facilities that have a Generating Capacity 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 that do not export power to the Utility, and have a Generating Capacity of 10 MW or less.

f. Level 4—For all Generating Facilities that do not qualify for Level 1, 2 or 3 interconnection review processes.

C. Applicable Standards

Unless waived by the Utility, a Generating Facility must comply with the following standards, as applicable:

1. IEEE Standard 1547-2008 for Interconnecting Distributed Resources with Electric Power Systems for Generating Facilities up to 10 MW in size;

2. IEEE Standard 1547.1 for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems;

3. UL 6142 Standard for Small Wind Turbine Systems; and

4. UL 1741 Standard for Inverters, Converters and Controllers for Use in Independent Power Systems. 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.[5] Certification of

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

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

a particular model or a specific piece of equipment is sufficient. It is also sufficient for an inverter built into a Generating Facility to be recognized as being UL 1741 compliant by a Nationally Recognized Testing Laboratory.

II. PRE-APPLICATION REPORT[6]

A. Pre-Application Report Request

1. A Pre-Application Report Request shall include:

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

   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. Generation technology and fuel source.

   d. $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 since there are many variables studied as part of the interconnection review process.

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6 A structured Pre-Application Report can reduce unnecessary interconnection Applications by providing information about system conditions at a proposed Point of Interconnection. Without this information, developers may submit multiple Applications to find out which of many potential project locations have the lowest costs, resulting in a high volume of Applications. Utilities may find it increasingly difficult to keep up with the number of Applications they have to review and it is inefficient for Utilities to have to process Applications that are unlikely to result in projects. It also raises the overall costs of development when developers are forced to try a scatter-shot approach to identify the lowest-cost opportunities. IREC's Pre-Application Report is based on the approach taken in California's Rule 21, which was revised in 2012. In addition to Pre-Application Reports, California's investor-owned utilities also are required to have a publicly available map of their systems, which provide basic information regarding voltage and capacity at specific points on the systems. Adoption of mapping tools may further reduce the number of requests for Pre-Application Reports that are filed.

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 Interconnection Request.

B. Pre-Application Report

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:

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

2. Allocated Capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.

3. Queued Capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.

4. Available Capacity (MW) of substation/area bus or bank and circuit most likely to serve proposed site.

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

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

7. Nominal distribution circuit voltage at the proposed site.

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

9. Relevant Line Section(s) peak load estimate, and minimum load data, when available.

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

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

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

13. 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.

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.

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 Inverter-Based Generating Facilities Not Greater than 25 kW

1. Application: An Applicant must submit a Level 1 Application using the standard form provided in Attachment 2 to these Interconnection Procedures, which may be sent electronically to a recipient designated by the Utility. Within three (3) Business Days of receipt, the Utility shall acknowledge receipt of the Application and notify Applicant whether or not the Application is complete. If the Application is incomplete, the Utility shall provide a written list detailing all information that must be provided to complete the Application. The Applicant shall have ten (10) Business Days after receipt of the list of incomplete material to submit the listed information, or to request an extension of time to provide such information. Otherwise, the Application will be deemed withdrawn. The Utility shall notify the Applicant within three (3) Business Days of receipt of a revised Application whether the Application is complete or incomplete. The Utility may deem the Application withdrawn if it remains incomplete. An Applicant executes the standard Interconnection Agreement for Level 1 by submitting a Level 1 Application.

2. Applicable Screens:

    a. Facility Size: The Generating Facility has a Generating Capacity not greater than 25 kW.

    b. For interconnection of a Generating Facility to a radial distribution circuit, the Generating Facility aggregated with all other generation capable of exporting energy on a Line Section will not exceed 15 percent of the Line Section's annual peak load as most recently measured at the substation or calculated for the Line Section.[7] A Line Section is that portion of the radial distribution circuit to which the Applicant seeks to interconnect and is bounded by automatic sectionalizing devices or the end of a distribution line.[8]

c. If the Generating Facility is to be interconnected on single-phase shared secondary, then the aggregate generation capacity on the shared secondary, including the Generating Facility, will not exceed 20 kilovolt-amps (kVA).

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 nameplate rating of the service transformer.

e. For interconnection of a Generating Facility within a Spot Network or Area Network, the aggregate generating capacity including the Generating Facility may not exceed 50 percent of the Network's anticipated minimum load.[9] 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 Network's measured minimum load in the previous year, if available;

ii. five percent of the Network's maximum load in the

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7 The intent of this screen is to assure that generation on a Line Section will not exceed load at any time, but utilities typically track peak loads and not minimum loads. Fifteen percent of peak load was established in the FERC procedures as a conservative estimate of minimum load. Inexplicably, the FERC procedures call for aggregate generation on the *circuit* to not exceed 15 percent of *Line Section* peak load, when the relevant comparison is Line Section generation versus Line Section load (the correction has been made here).

8 Typically, a radial distribution circuit does not have automatic sectionalizing devices, so the whole circuit is one Line Section. A fuse must be manually replaced and is therefore not considered an automatic sectionalizing device.

9 Area Networks and Spot Networks use a network protector on each feeder serving the network and these protectors normally remain closed. It is important that generation not exceed load on the network to avoid the possibility of operating one or more network protectors.

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 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 detailed information on the reason(s) for failure in writing. In addition, the Utility shall either:

   a. Notify Applicant in writing that the Utility is continuing to evaluate the Generating Facility under Supplemental Review if the Utility concludes that the Supplemental Review might determine that the Generating Facility could continue to qualify for interconnection pursuant to Level 2; or

   b. Offer to continue evaluating the Interconnection Request under Level 4.[10]

5. Approval: If the proposed interconnection meets all of the applicable Level 1 screens, the Interconnection Request shall be approved and the Utility will provide the Applicant an executable Interconnection Agreement within the following timeframes.

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[10] In some cases, an Applicant's facility may require upgrades whose costs are so significant that they are prohibitive. In these cases, a Utility sometimes refers to the particular circuit where the Applicant is trying to interconnect as "full" or "closed," meaning that no more projects may interconnect to that circuit without prohibitively costly upgrades. These Interconnection Procedures leave the decision about whether or not to pay for necessary upgrades to the Applicant, who will ultimately bear the burden of these high upgrade costs, rather than attempting to define what constitutes a full or closed circuit. Moreover, in order to avoid this situation, a Utility could direct Applicants and potential Applicants toward more optimal locations on the Utility's Electric Distribution System, for example through the Pre-Application process described in Section II or through publicly available mapping tools.

a. If the proposed interconnection requires no construction of facilities by the Utility on its own system,[11] the interconnection agreement shall be provided within three (3) Business Days, the Utility shall send the Applicant a copy of the Application form, signed by the Utility, forming the Level 1 Interconnection Agreement. If a Utility does not notify an Applicant in writing or by email within twenty (20) Business Days whether an Application is approved or denied, the Interconnection Agreement signed by the Applicant as part of the Level 1 Application shall be deemed effective.[12]

b. If the proposed interconnection requires only Interconnection Facilities or Minor System Modifications, the Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, shall be provided within fifteen (15) Business Days after notification of the Level 1 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 thirty (30) Business Days after notification of the Level 1 review results, or the Utility may notify the Applicant that the Utility will need to complete a Facilities Study under Section III.F to determine the necessary upgrades.[13]

6. Unless extended by mutual agreement of the Parties, within six (6) months

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[11] 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.

[12] In most cases approval by the local municipal electrical inspector will still be required to commence operation.

[13] Many states' interconnection procedures contain some version of a "no construction screen," which prohibits Generating Facilities that pass other technical screens for expedited interconnection review from obtaining an Interconnection Agreement if they require construction of any facilities by the Utility on its system. This "no construction screen" results in unnecessary studies and can be particularly problematic for Generating Systems wishing to interconnect in locations without onsite load. In contrast, the approach taken here gives utilities additional time to provide a cost estimate along with an Interconnection Agreement if it determines that upgrades are necessary, with timeframes dependent on whether these are Minor System Modifications or something more. Alternatively, the Utility may opt to proceed directly to a Facilities Study, bypassing the Impact Study.

of formation of an Interconnection Agreement or six (6) months from the completion of any upgrades, whichever is later, the Applicant shall provide the Utility with at least ten (10) Business Days notice of the anticipated start date of the Generating Facility.

7. A Utility may conduct an inspection within ten (10) Business Days of receiving the notice of the anticipated start date at a time mutually agreeable to the Parties. 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.

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 passed any inspection required by the Utility.[14] Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 5 or other inspector-provided documentation.

9. A Utility may elect to charge a standard Application fee of up to $100 for Level 1 review.[15]

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. Application: An Applicant must submit a Level 2 Application using the standard form provided in Attachment 3 to these Interconnection Procedures, which may be sent electronically to a recipient designated by the Utility. Within three (3) Business Days of receipt, the Utility shall acknowledge receipt of the Application 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 must be provided to complete the Application. The Applicant will have ten (10) Business Days after receipt of the list to submit the listed information, or to request an extension of time to provide such information. Otherwise, the Application will be deemed withdrawn. The Utility shall notify the Applicant within three (3) Business Days of receipt of a revised

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

[15] States have set Level 1 Application fees in a range from $0 to $800. California and other states with extensive renewable energy installations have chosen $0 for net-metered facilities.

Application whether the Application is complete or incomplete. The Utility may deem the Application withdrawn if it remains incomplete.

2. Applicable screens:

a. Facility Size:[16] Generating Facility's Generating Capacity 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 aggregated with all other generation capable of exporting energy on a Line Section will not exceed 15 percent of the Line Section's 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 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

[16] The distribution line voltage at the point of interconnection is one of the key factors in determining whether a project can interconnect without full study. Likewise, larger generators may pose a lower likelihood of imposing impacts that require study when located close to the substation and on main feeder lines. These factors have been taken into account when setting the size limits for Level 2 in these Interconnection Procedures.

interrupting capability.[17]

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.[18]

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

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, will not exceed sixty-five percent of the transformer nameplate power rating.[19]

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17 The FERC Small Generator Interconnection Procedures set the threshold at 87.5 percent of short circuit interrupting capability, but utility equipment can handle much more current than ratings allow. The utility source of fault current should always be greater than any DG source, by a significant margin, so moving toward 100% makes sense. Fault currents are always calculated with worst-case scenarios, and the actual fault current will be lower than the calculated.

18 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.

19 The FERC Small Generator Interconnection Procedures set the threshold at 20 kW,

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, 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.[20]

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.[21] At the

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however that may be too large in some instances and too small in others. A 2011 Sandia National Laboratory study suggests that this is an appropriately conservative threshold, which would effectively identify high-risk interconnection requests. *See* "Evaluation of Alternatives to the FERC SGIP Screens for PV Interconnection Studies," Broderick, et. al. (2011). This approach has also been adopted in New Mexico.

20 This screen is traditionally intended to address whether a Generating Facility may contribute to known or posted transient stability issues, although IREC recognizes that there are no transient stability issues posted by most of the Independent System Operators and thus it is often hard for utility distribution engineers to apply this screen. In addition, the screen addresses whether the proposed generating facility has interdependencies with other queued generators on the Electric Distribution System and therefore needs further study. This latter component follows approaches to this issue taken in California (Rule 21) and in the PJM FERC-regulated tariff.

21 The intent of minimum import relays is to minimize nuisance operation of network protectors by assuring that power is always flowing into the network. For some networks, 1 percent of maximum load will be too much of a minimum import requirement; for

Utility's discretion, the requirement for minimum import relays or other protective schemes may be waived.

3. Time to process under screens: 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. 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 detailed information on the reason or reasons for failure. In addition, the Utility shall either:

    a. Notify Applicant in writing that the Utility is continuing to evaluate the Generating Facility under Supplemental Review if the Utility concludes that the Supplemental Review might determine that the Generating Facility could continue to qualify for interconnection pursuant to Level 2; or

    b. Offer to continue evaluating the Interconnection Request under Level 4.

5. Approval: If the proposed interconnection passes the screens, the Interconnection Request 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,[22] the interconnection agreement shall be provided within three (3) Business Days after the notification of Level 2 review results.

    b. If the proposed interconnection requires only Interconnection Facilities or Minor System Modifications, the interconnection agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, shall be provided within

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instance, a sports stadium on a Spot Network may experience very light daytime loads when the stadium is not in use. Minimum import requirements can be relaxed for such networks.

22 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.

fifteen (15) Business Days after notification of the Level 2 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 thirty (30) Business Days after notification of the Level 2 review results, or the Utility may notify the Applicant that the Utility will need to complete a Facilities Study under Section III.F to determine the necessary upgrades.[23]

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 provide the Utility with at least ten (10) Business Days notice of the anticipated start date of the Generating Facility.[24]

7. The Utility may conduct an inspection within ten (10) Business Days of receiving the notice of the anticipated start date at a time mutually agreeable to the Parties. 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 it must provide a written explanation detailing the reasons and any standards violated.

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.[25] Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 5 or other inspector-provided documentation.

9. A Utility may elect to charge a standard Application fee of up to $100 plus

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[23] *See* note 13 regarding "no construction screens."

[24] For larger Generating Facilities, an Applicant may need six months or more, to secure financing, equipment, and zoning approvals.

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

$10 per kW of Generating Capacity up to a maximum of $2,000 for Level 2 review.

C. Level 3 Screening Criteria and Process for Non-Exporting Generating Facilities Not Greater than 10 MW

An Applicant may use the Level 2 process for a Generating Facility with a Generating Capacity no greater than ten MW that uses reverse power relays, minimum import relays or other protective devices to assure that power may never be exported from the Generating Facility to the Utility.[26] An Applicant proposing to interconnect a Generating Facility to a Spot Network or an Area Network may not use Level 3.

D. Supplemental Review[27]

1. Within twenty (20) Business Days of determining that Supplemental Review is appropriate, 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 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 aggregate Generating Facility capacity on the Line Section 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 aggregate Generating Facility capacity on the Line Section is less than 30 percent of the peak load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Generating Facility.

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26 Note that the first screen in Level 2 is inapplicable to a Level 3 Applicant because that screen limits aggregate "generation capable of exporting energy."

27 A clear Supplemental Review process can enable efficient interconnections at higher penetrations while still ensuring system protection. Specifically, it can maintain a fast process for projects in low-penetration areas, but can provide Utilities with sufficient time to conduct additional analysis in higher penetration cases where full study is not necessary. The full study process (Level 4) is typically lengthy and costly; however, an abbreviated study process may be appropriate for certain projects, such as projects that do not exceed 100 percent of minimum load on a circuit. In addition to benefiting generators by minimizing their review time and costs, a robust Supplemental Review process may help to minimize congestion in Utility study queues. The approach proposed here has been adopted in California (Rule 21), and is under consideration in Massachusetts and Ohio, as well as at FERC. Hawaii has also adopted a similar approach to its supplemental review.

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. When this screen is being applied to a Generating Facility that serves some onsite electrical load, only the net export in kW, if known, that may flow into the Utility's system will be considered as part of the aggregate generation.

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 1453 or utility practice similar to IEEE 1453; and

iii. The harmonic levels meet IEEE 519 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., $\leq$ 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 Interconnection Request shall be approved and the Utility will provide the Applicant an executable Interconnection Agreement within the timeframes established below.

a. If the proposed interconnection requires no construction of facilities by the Utility on its own system, the Interconnection Agreement shall be provided within five (5) Business Days after the notification of the Supplemental Review results.

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

c. If the proposed interconnection requires more than Supplemental Review, 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 thirty (30) Business Days after notification of the Supplemental Review results, or the Utility may notify the Applicant that the Utility will need to complete a Facilities Study under Level 4 to determine the necessary upgrades.

3. 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.

   a. For Level 1 Applicants: 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 provide the Utility with at least ten (10) Business Days notice of the anticipated start date of the Generating Facility.

   b. For Level 2 and 3 Applicants: 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 provide the Utility with at least ten (10) Business Days notice of the anticipated start date of the Generating Facility.[28]

4. The Utility may conduct an inspection within ten (10) Business Days of receiving the notice of the anticipated start date at a time mutually agreeable to the Parties. 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.

5. 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.[29] Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 5 or other inspector-provided documentation.

E. Applicant Options Meeting[30]

[28] For larger Generating Facilities, an Applicant may need six months or more, to secure financing, equipment, and zoning approvals.

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

[30] California integrated this approach into its Rule 21 to allow an Applicant and the Utility another opportunity to discuss the interconnection of the facility before undertaking the typically lengthy and costly study process (Level 4).

If the Utility determines the Interconnection Request 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, it 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 that it requests an Applicant Options Meeting or that it would like to proceed to Level 4 review in writing within fifteen (15) Business Days of the Utility's notification or the Interconnection Request shall be deemed withdrawn. If the Applicant requests an Options Meeting, the Utility shall offer to convene a meeting at a mutually agreeable time within the next fifteen (15) Business Days.

F. Level 4 Process for All Other Generating Facilities

1. Application: An Applicant must submit a Level 4 Application 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 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, 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 must be provided to complete the Application. The Applicant will have twenty (20) Business Days after receipt of the list to submit the listed information, or to request an extension of time to provide such 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 Application is complete or incomplete. The Utility may deem the Application withdrawn if it remains incomplete.

2. The Utility will conduct an initial review that includes a scoping meeting with the Applicant within ten (10) Business Days of determination 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 will 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 Impact Study or Facilities Study may be waived.

3. If the Parties do not waive the Impact Study, within five (5) Business Days

of the completion of the scoping meeting, the Utility shall provide the Applicant with an agreement in the form of the Impact Study in Attachment 6, including a good faith estimate of the cost and time to undertake the Impact Study.

4. An Impact Study for a Generating Facility with a Generating Capacity of no more than 10 MW shall include a review of the Generating Facility's protective devices for adherence to IEEE Standard 1547. An Impact Study for a Generating Facility with a Generating Capacity of more than 10 MW shall use IEEE Standard 1547 for guidance. For Generating Facility components that are Certified, the Utility may not charge the Applicant for review of those components in isolation.

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

    a. Load-Flow Study

    b. Short-Circuit Study

    c. Circuit Protection and Coordination Study

    d. Impact on System Operation

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

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

6. Once an Applicant delivers an executed Impact Study agreement and payment in accordance with that agreement, the Utility will conduct the Impact Study. The Impact Study shall be completed within forty (40) Business Days of the Applicant's delivery of the executed Impact Study agreement, although the Utility may take longer when a proposed Generating Facility will be impacted by other proposed Generating Facilities.

7. If the Utility determines that Electric Delivery System modifications required to accommodate the proposed interconnection are not substantial, the Impact Study will identify the scope and cost of the modifications defined in the Impact Study results and no Facilities Study shall be required.

8. If the Utility determines that necessary modifications to the Utility's

Electric Delivery System are substantial, the results of the 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.

9. If the Parties do not waive the Facilities Study, within five (5) Business Days of the completion of the Impact Study, the Utility shall provide a Facilities Study agreement, in the form of the Facilities Study in Attachment 6, including a good faith estimate of the cost and time to undertake the Facilities Study.

10. Once the Applicant executes the Facilities Study agreement and pays the Utility pursuant to the terms of that agreement, the Utility will conduct the Facilities Study. The Facilities Study shall include a detailed list of necessary Electric Delivery System upgrades and a cost estimate for completing such upgrades, which may not be exceeded by 125 percent in any future Utility facilities installation. The Facilities Study shall be completed within sixty (60) Business Days of the Applicant's delivery of the executed Facilities Study agreement, though the Utility may take longer when a proposed Generating Facility will be impacted by other proposed Generating Facilities.

11. Within five (5) Business Days of completion of the last study that the Utility deems necessary, the Utility shall execute and send the Applicant an Interconnection Agreement using the standard form agreement provided in Attachment 4 of these Interconnection Procedures. The Interconnection Agreement shall include a quote for any required Electric Delivery System modifications, subject to the cost limit set by the Facilities Study cost estimate. The Facilities Study shall 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.

12. Within forty (40) Business Days of the receipt of an Interconnection Agreement,[31] 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

[31] Typically, the Applicant will be eager to sign and return the Interconnection Agreement quickly, particularly where no expense is involved. However, the Interconnection Agreement can include a significant commitment by the Applicant to pay for Utility upgrades. Forty Business Days are provided to allow the Applicant time to finalize financing, if needed.

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.

13. The Utility shall inspect the completed Generating Facility installation for compliance with requirements and shall attend any required commissioning tests pursuant to IEEE Standard 1547. For systems greater than 10 MW, IEEE Standard 1547 may be used as guidance. 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.

14. The Applicant shall notify the Utility if there is any change in the anticipated start date of interconnected operations of the Generating Facility. 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. Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 5 or other inspector-provided documentation.

15. Fees: An Application fee shall not exceed \$100 plus \$10 per kW of Generating Capacity 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.

IV. GENERAL PROVISIONS AND REQUIREMENTS

A. Online Applications and Electronic Signatures

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

2. Each Utility shall dedicate a page on their website to interconnection procedures. That page shall be able to be reached by no more than three logical, prominent hyperlinks from the Utility's home page.[32] The relevant

[32] For instance, a Utility's home page could have a hyperlink to a subpage for clean energy,

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.[33]

B. Dispute Resolution

1. For a dispute related to these rules, either Party may submit a written request to the other Party for an informal meeting by phone, electronic media, or in person to attempt to resolve the dispute. Following such a request, each Party shall make available a person with authority to resolve the dispute. A meeting shall be scheduled for at least one hour, but may be shorter at the option of the Party requesting the meeting. The meeting shall take place at a time and in a manner agreeable to the Party receiving the request within three (3) Business Days of the Party's receipt of the request for a meeting. If a dispute involves technical issues, persons with sufficient technical expertise and familiarity with the issue in dispute from each Party shall attend the informal meeting.

2. If an informal meeting of the Parties does not resolve a dispute, the Parties may mutually agree to further discussions or either Party may seek resolution of the dispute through the complaint or mediation procedures available at the Commission. Dispute resolution at the Commission will be initially conducted in an informal, expeditious manner to reach resolution with minimal costs and delay. If no resolution is reached after informal discussions, either Party may file a formal complaint with the Commission.

C. Utility Reporting Requirement

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which has a hyperlink to a subpage for customer-sited generation, which has a hyperlink to these procedures.

[33] Electronic signatures are generally recognized in commercial activities, and 47 states have adopted the substance of the Uniform Electronic Transaction Act (UETA), a model act developed by the National Conference of Commissioners on Uniform State Laws.

Each Utility shall electronically make available a spreadsheet listing all interconnected Generating Facilities with their respective resource types, Generating Capacities, year of interconnection, and zip code of geographic location. At a minimum, such information shall be provided to the Commission by March 1 of each year. Such information shall be submitted in both a database format for data analysis and in an image format that is legible and intuitive when printed.

D. 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.

4. The authorized hourly rate for engineering review under Supplemental Review or Level 4 shall be $100 per hour.[34]

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[35]), or to perform or pay for additional tests to obtain approval to interconnect.

6. A Utility may only require an Applicant to purchase insurance covering

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[34] 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.

[35] 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.

Utility damages, and then only in the following amounts:[36]

a. For non-inverter-based Generating Facilities:

Generating Capacity > 5 MW	$3,000,000
2 MW < Generating Capacity $\leq$ 5 MW	$2,000,000
500 kW < Generating Capacity $\leq$ 2 MW	$1,000,000
50 kW < Generating Capacity $\leq$ 500 kW	$500,000
Generating Capacity $\leq$ 50 kW	no insurance

b. For inverter-based Generating Facilities:

Generating Capacity > 5 MW	$2,000,000
1 MW < Generating Capacity $\geq$ 5 MW	$1,000,000
Generating Capacity $\geq$ 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 interconnection equipment Certified in accordance with Section I.C.

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.

9. 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, an annual test in which the Interconnection Customer's Generating Facility is disconnected from the Utility's equipment to ensure that the Generating Facility stops delivering power to the Electric Delivery System.

   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

[36] 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.

has jurisdiction over the interconnection. Periodic test reports or a log for inspection shall be maintained.

10. 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.

11. 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.

12. 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.[37]

13. 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.[38] 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.

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[37] 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.

[38] 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.

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.[39] 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.

"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.

"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 Standard 1547.

"Available Capacity" means the Total Capacity less the sum of Installed Capacity and Queued Capacity.

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

"Certified" has the meaning provided in Section I.C of these procedures, regarding IEEE and UL standards applicable to Generating Facility components.

"Commission" means the *[insert name of the state utility commission]*.[40]

"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.

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[39] 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.

[40] For a utility not regulated by a state utility commission, the regulator of the utility should be listed with the appropriate defined term, such as "Board" instead of "Commission."

"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.

"Facilities Study" has the meaning provided in Section III.F and Attachment 6 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 rated capacity of a Generating Facility in alternating current (AC). For an inverter-based Generating Facility, the Generating Capacity is the rated capacity of the inverter.

"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.

"Impact Study" has the meaning provided in Section III.F and Attachment 6 of these procedures.

"Installed Capacity" means existing aggregate generation capacity in megawatts (MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online).

"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 2 to these Interconnection Procedures. For Levels 2, 3 or 4, the standard form Interconnection Agreement is provided in Attachment 4 to these Interconnection Procedures.

"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.[41]

"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 2 of these procedures.

Level 2 has the meaning provided in Section III.B and Attachments 3 and 4 of these procedures.

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

Level 4 has the meaning provided in Section III.D and Attachments 3 and 4 of these procedures.

"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 the Application or an Interconnection Request with a later queue priority date.

"Minor System Modifications" means modifications to a Utility's Electric Delivery System, including activities such as changing the fuse in a fuse holder cut-out, changing the settings on a circuit recloser and other activities that usually entail less than four hours of work and $1000 in materials.

"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 in the interconnection of a Generating Facility with an Electric Delivery System at which the harmonic limits are applied and shall have the same meaning as in IEEE Standard 1547.

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41 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.

"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.

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

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

"Queued Capacity" means the aggregate generation capacity in MW of Applicants' Generating Facilities intending to interconnect to a substation/area bus, bank or circuit.

"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 Standard 1547.

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

"Total Capacity" means the aggregate capacity of a substation/area bus, bank or circuit and is equal to the sum of Installed Capacity, Available Capacity and Queued Capacity.

"UL" means Underwriters Laboratories, 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.[42]

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[42] 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:
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.

Applicant:

Name: ____

Address: ____

City: State, Zip: ____

Telephone (Day): ______________________ (Evening): ______________________

Fax: ____________________ Email Address: ______________________________

Utility Customer Number (if applicable): ______________________________

Electricity Provider (if different from Utility):______________________________

Contact: (if different from Applicant)

Name: ____

Address: ____

City, State, Zip: ____

Telephone (Day): ______________________ (Evening): ______________________

Fax: ____________________ Email Address: ______________________________

Generating Facility:

Location (if different from above): ______________________________

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

____

Inverter Manufacturer: ____

Model: ____

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

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

System Design Capacity: ____________ (kW) ______________ (kVA)

Prime Mover: Photovoltaic / Turbine/ Fuel Cell / Other (describe): ____________________

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

Is the equipment UL1741 Listed? Yes: _______ No: ________

If Yes, attach evidence of UL1741 listing.

Estimated Installation Date: ______________ Estimated In-Service Date: _________________

List components of the Interconnection Equipment Package that are certified:

Equipment Type	Certifying Entity
1. ______________________________________	___________________________________
2. ______________________________________	___________________________________
3. ______________________________________	___________________________________

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

Applicant Signature (may be electronic)

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 and IEEE standard; or

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

2.2.3 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 Standard 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 is reasonable 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 3:
Level 2, Level 3 and Level 4 Interconnection Application

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.

Applicant requests review under (select one):

______ Level 2 _______ Level 3 ________ Level 4

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

Utility: ____

Address: ____

Fax Number: ____

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: ____

Generating Facility Location (if different from above): ______________________________

Telephone (Day): ______________________ (Evening):___________________________

Fax: __________________________________ 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): ____________

2. Generating Facility Specifications

Prime Mover: Photovoltaic / Turbine/ Fuel Cell / Other (describe): ________________________

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

Type of Generating Facility: ____ Inverter ____ Synchronous ____ Induction

Generating Facility Nameplate Rating: _________________(kW) ___________________ (kVA)

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

Typical Reactive Load (if known): ___________________

Maximum Physical Export Capability Requested: _______________ kW

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

Individual generator data (attach additional sheets if needed)

Manufacturer, Model Name & Number: ____

Version Number: ____

Nameplate Output Power Rating in kW: (Summer) ___________ (Winter) _______________

Nameplate Output Power Rating in kVA: (Summer) ___________ (Winter) _____________

Rated Power Factor: (Leading) _____________________ (Lagging) _____________________

Total Number of generators to be interconnected pursuant to this Application: _______________

Elevation: __________________

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

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

____

Inverter-based Generating Facilities

Inverter Manufacturer, Model Name & Number: ____

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

Harmonics Characteristics: ______________________________

Start-up requirements: ______________________________

Rotating Machines (of any type)

RPM Frequency: ______________________________

Neutral Grounding Resistor (If Applicable): ______________________________

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.

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

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

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

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

Manufacturer: ___________________ Type: _____________ Size: ________Speed: __________

Interconnecting Circuit Breaker: (if applicable)

Manufacturer: _________________________ Type: ________________________________

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

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.	______________________	______________________	______________________

Discrete Components: (if applicable)

(Enclose 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: ____________________________

<u>Current Transformer Data:</u> (if applicable)

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

Manufacturer: ____

Type: _____________ Accuracy Class: ___________ Proposed Ratio Connection: ______

<u>Potential Transformer Data:</u> (if applicable)

Manufacturer: ____

Type: _____________ Accuracy Class: ___________ Proposed Ratio Connection: ______

4. General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Generating Facility equipment, current and potential circuits, and protection and control schemes. 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 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 copy of any site documentation that describes and details the operation of the protection and control schemes.

Is available documentation enclosed? ______ Yes ______ No

Enclose 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 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 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 5 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 4:
Level 2, 3 and 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 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.

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

1.5.4 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, Underwriters Laboratories, and any operating requirements.

1.5.5 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.

1.5.6 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 Standard 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 5 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 leading to 0.95 lagging.

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. 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 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.D.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: ____________________________ Fax: ____________________

Email: ____________________________

Utility:

Attention: ______________________________________

Address: _______________________________________

City: ______________________________ State: _______ Zip: ________

Phone: ____________________________ Fax: ____________________

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: ______________________________ Fax: ____________________

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. 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: ______________________________ Fax: ____________________

Email: ______________________________

Utility's operating representative:

Attention: ____

Address: ____

City: ________________________________ State: _______ Zip: ________

Phone: ______________________________ Fax: ____________________

Email: ______________________________

Article 11. Signatures

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

<u>For the Utility</u>:

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

<u>For the Interconnection Customer</u>:

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Exhibits incorporated in this Agreement: [*which 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 Standard 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 apply to Levels 1, 2 or 3 interconnections but may apply, in the discretion of the Utility, to Generating Facilities approved under Level 4);

f) copies of, Impact and Facilities Study agreements.]

ATTACHMENT 5:
Certificate 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): _________________________________
Facsimile Number: _____________________ E-Mail Address: ____________________________

Electrician:

Installing Electrician: ___________________________ Firm: ___________________________
License No.: ____
Mailing Address: ____
City: _______________________________ State: ______________ Zip Code: _____________
Telephone (Daytime): ___________________ (Evening): _________________________________
Facsimile Number: _____________________ 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 6:
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 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. Sample study agreements are provided on the following pages.

Interconnection 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 to perform an 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 an Impact Study consistent with Section III.F of the Interconnection Procedures.
3. The scope of the 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 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 Impact Study may be extended.
5. The 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.

7. The 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 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

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 on; and

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

Whereas, the Utility has completed or waived an 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 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 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 description, estimated cost, and schedule for required facilities to interconnect the Generating Facility to the Electric Delivery System and (2) shall address the short circuit, instability, and power flow issues identified in the 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 $10,000.
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, 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 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 Impact Study (if performed)?

_______ Yes ______ No

Exhibit SCS-4

Kevin Fox, et al., Updating Small Generator Interconnection Procedures, National Renewable Energy Laboratories (Dec. 2012), available at: http://www.nrel.gov/docs/fy13osti/56790.pdf.

Exhibit SCS-4

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Updating Small Generator Interconnection Procedures for New Market Conditions

Kevin Fox, Sky Stanfield, Laurel Varnado, and Thad Culley
Keyes, Fox & Wiedman LLP

Michael Sheehan, P.E.
Failte Group LLC

Michael Coddington
National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
NREL/TP-5500-56790
December 2012

Contract No. DE-AC36-08GO28308

Updating Small Generator Interconnection Procedures for New Market Conditions

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National Renewable Energy Laboratory

Prepared under Task No. SM12.2040

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NOTICE

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Table of Contents

ACRONYMS

CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
DG	Distributed generation
FERC	Federal Energy Regulatory Commission
FIT	Feed-in tariffs
GW	Gigawatts
IEEE	Institute of Electrical and Electronics Engineers
ISP	CAISO Independent Study Process
kV	Kilovolts
kVA	Kilovolt-Amps
MW	Megawatts
MWh	Megawatt hours
PCC	Point of Common Coupling
PG&E	Pacific Gas & Electric
PV	Photovoltaic
RPS	Renewable Portfolio Standards
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SEPA	Solar Electric Power Association
SGIA	Small Generator Interconnection Agreement
SGIP	FERC Small Generator Interconnection Procedures
UETA	Uniform Electronic Transaction Act
WDAT	Wholesale Distribution Access Tariffs

EXECUTIVE SUMMARY

This report recommends reforms to federal and state interconnection procedures to meet the demands of a growing national marketplace for solar photovoltaic (PV) and other small renewable generators that interconnect to electric distribution systems. Updating federal and state interconnection processes can have a significant, positive impact on the efficiency and transparency with which renewable energy systems are interconnected nationwide, which in turn can have a significant impact on the cost of meeting state policy goals. For instance, with increasing interconnection applications, recent experience shows many applications at the distribution system-level do not actually go forward to implementation. Thus, reforming interconnection procedures may indeed make the process more effective for everyone involved – system owner and integrators, as well as the electric utilities.

Interconnection processes serve two fundamental purposes: 1) they provide a transparent and efficient means to interconnect generators to the electric power system; and 2) they maintain the safety, reliability and power quality of the electric power system. Federal and state regulators are faced with the challenge of keeping interconnection procedures updated against a backdrop of evolving technology, new codes and standards, and considerably transformed market conditions. This report is intended to educate policymakers and stakeholders on beneficial reforms that will keep interconnection processes efficient and cost-effective while maintaining a safe and reliable power system. Although the discussion in this report focuses on PV, which is the dominant generating technology presently seeking interconnection to electric distribution systems, the interconnection reforms recommended in this report apply to all generating technologies.

Section 1 of the report provides a concise history of the major activities that helped shape the national landscape for interconnection procedure development between 2000 and 2006. Section 1 highlights the development of statewide interconnection procedures for small generators in California in 2000; the development of Institute of Electrical and Electronics Engineers (IEEE) Standard 1547: *The Standard for Interconnecting Distributed Resources With the Electric Power System* in 2003; the Federal Energy Regulatory Commission's promulgation of Small Generator Interconnection Procedures (SGIP) in 2005; and the federal Energy Policy Act of 2005 and its impact on state consideration of interconnection policies to facilitate growth in distributed energy resources.

Section 2 outlines three substantial market evolutions since 2006 that have triggered the need for interconnection reform across the United States. These new market conditions include: 1) tremendous growth in solar PV markets, prompted by state renewable energy goals; 2) an increase in generating system sizes and generators that do not primarily serve onsite load; and 3) growing areas of high solar penetration that raise new considerations for both utilities and developers in managing further development.

Section 3 discusses specific modifications worth considering, including expanding the amount of information made available to developers in a pre-application report process;

increasing the efficiency with which interconnection applications are processed, particularly for very small generators; updating initial technical review screens to increase the reliability and safety of interconnections; providing a supplemental review process for projects that fail initial review screens; and streamlining the study process to make more efficient use of utility resources and spread system upgrade costs across interconnection applicants.

Section 4 recaps and summarizes the recommendations provided in Section 3.

Attachment 1 provides California Rule 21 Supplemental Review Screens (Rule 21 G.2)

INTRODUCTION

By 2015, the United States will need to interconnect more than 30,000 MW of new renewable generating capacity to meet existing state and federal renewable energy policy goals.[1] By 2035, the additional generating capacity needed to satisfy existing policy goals increases to 100,000 MW.[2] Already, state and federal policies are promoting nearly 1,900 MW of solar PV installations annually.[3]

State and federal interconnection policies, which clarify the steps and responsibilities for interconnecting new generating facilities to the nation's electric power system, have a direct and substantial impact on the timing and cost of bringing new generating capacity online. An effective interconnection process, which contributes to lowering the cost of interconnection and therefore the overall cost of developing new capacity, facilitates market entry by smaller generators, increases wholesale market competition, and encourages investment in needed generating capacity and electric transmission and distribution system infrastructure.[4]

Ensuring that federal and state interconnection processes are adequate is a necessary step to achieving these goals. However, the effort required to update interconnection policy can overwhelm even a well-resourced regulatory agency. Interconnection policies address complex, technical issues, and the utilities and developers that engage in the process often have divergent views about the goals the process should aim to achieve.

Utilities are responsible for maintaining the safety and reliability of electric power systems. Many are liable to regulators for their failure to do so. From a utility standpoint, the interconnection of even a small generator can raise potential safety and reliability impacts that may need to be addressed. Utilities are thus inclined to want sufficient time to process interconnection applications to protect against any diminution in safety, reliability and service quality that may expose the utility to increased levels of risk. If there is any possibility for reliability or safety impacts, utilities will want to study those impacts to determine appropriate protective or mitigating measures.

For developers, the interconnection process is one of the most time-consuming and costly aspects of developing a generating facility. Frequently, developers claim that the process is opaque and consists largely of internal utility business practices such that implementation varies drastically from utility to utility.[5] Moreover, this lack of transparency and certainty introduces significant development risk. Delays in the interconnection process slow development and may undermine access to valuable tax incentives and utility solicitations.

Developers typically want greater access to information about the electric power system so they can better determine lower-cost, lower-impact places to interconnect. They also want more certainty and transparency regarding the cost and timeline for processing interconnection studies and greater justification by utilities as to why any interconnection upgrade requirements mandated by them are indeed necessary.[6]

Regulators are faced with the often challenging task of balancing these divergent perspectives to find "win-win" solutions that allow utilities to maintain the safety and reliability of electric power systems while providing developers a transparent, efficient, and cost-effective process that operates on reasonably predictable timeframes. Regulators are also faced with the challenge of keeping interconnection processes up to date against a backdrop of evolving technology, updates to relevant codes and standards, and changed market conditions.

Over the past decade, the combination of increasing electricity prices, decreasing cost of small generator technology, and strong financial incentives for renewable energy has triggered states such as California, Colorado, Hawaii, Massachusetts, New Jersey, and others to experience high volumes of interconnection applications and, in certain areas, high penetrations of solar PV and other renewable generators on their electric distribution systems. In these states, increased market interest in small to medium scale renewable projects has overwhelmed existing interconnection processes, leading to bottlenecks and significant delays.[7] Regulators have been called upon in those states to update interconnection policies to keep pace with the changed market conditions.

To assist with a reevaluation of existing interconnection policies, the National Renewable Energy Laboratory (NREL), United States Department of Energy, Sandia National Laboratories, and the Electric Power Research Institute published a February 2012 report titled *Updating Interconnection Screens for PV System Integration* ("*Interconnection Screens Report*").[8] The *Interconnection Screens Report* makes recommendations to improve the screening process for interconnection applications, with a focus on a ubiquitous 15% penetration screen that is found in many federal and state interconnection processes.[9] This screen is perceived as a significant barrier to PV deployment by many solar developers and other stakeholders.[10]

Recognizing the 15% screen as a perceived barrier to reaching higher penetrations of deployed solar PV systems, the *Interconnection Screens Report* makes short, medium and long-term recommendations to update this screen. The short-term recommendations include simple modifications to the screening process to include PV-specific screening criteria that better account for the daytime generating profile of solar PV. Longer-term solutions require cooperation among regulatory and governmental agencies, utilities, PV developers and others to work toward more widespread interconnection reform.

This paper follows up the *Interconnection Screens Report* to discuss ways in which state and federal regulators have recently reformed interconnection processes in light of changed market conditions, looking beyond just the 15% penetration screen. Relying on state practices and the *Interconnection Screens Report's* technical recommendations, this paper offers practical suggestions for updating state and federal interconnection policies. Recommendations in this paper focus on:

- Improved access to information about distribution system conditions at points of interconnection that enable applicants to self-screen projects in a manner that reduces applications for interconnections in certain areas
- Increased efficiency in the application process for very small, certified inverter-based systems that pose a low likelihood of adverse system impacts of the sort that require extensive study
- Modified fast track technical screens to accommodate generators interconnecting under new procurement programs and new renewable energy policies
- Expanded use of supplemental review for higher-penetration scenarios
- Improvements in the interconnection study process to streamline review and allow for efficiencies in processing applications.

Where appropriate, this paper suggests model interconnection procedure language to help inform decisions of federal and state regulators exploring this topic.

1. HISTORY OF SMALL GENERATOR INTERCONNECTION PROCEDURES

Existing interconnection processes for small generators were largely developed between 2000 and 2006 with few significant updates since that time. Prior to 2000, few states had uniform interconnection procedures. Instead, utilities regularly determined the procedural requirements that would govern the interconnection process on a case-by-case basis.[11]

For lack of another proven approach, many utilities applied interconnection procedures they had in place for qualifying facilities under the federal Public Utility Regulatory Policies Act of 1978. These procedures were largely designed for facilities interconnecting to high-voltage transmission lines and were often more cumbersome and expensive than what was needed for smaller facilities interconnecting to low- and medium-voltage distribution lines.[12] This created inefficiencies in which lengthy and costly studies were often required only to determine that upgrade costs would make a generator financially infeasible. This was particularly problematic for modestly-sized residential and commercial solar PV systems that were primarily intended to serve onsite energy needs.

A series of developments from 2000 to 2006 led to a rapid evolution in the development of standard interconnection processes for small generators interconnecting to distribution systems. This section provides an overview of the rapid evolution and deployment of interconnection procedures in the U.S. during that period.

December 2000: California's Rule 21

In 2000, California was among the first states to adopt comprehensive procedures for distribution system interconnections when the California Public Utilities Commission adopted Rule 21.[13] Rule 21 implemented a screening process through which utilities could easily and objectively review an interconnection application to determine whether further studies or additional protective measures may be required. The initial review screens were designed primarily to ease the interconnection process for generators intended to serve onsite load. Rule 21 also included timelines to ensure the interconnection process would move forward in a timely manner.

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

June 2003: IEEE 1547 Standard

In 2003, the IEEE developed technical Standard 1547: *The Standard for Interconnecting Distributed Resources with the Electric Power System.* Standard 1547 provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of distributed generation (DG) interconnection with electric power systems. Specifically, it provides comprehensive guidelines for "responses to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests."[14] It was developed through an extensive, consensus-based stakeholder process and has since received widespread support and has informed the technical requirements found in federal and many state interconnection policies for small generators.

The IEEE 1547 standard is not a single static standard. However, it is the first in a family of standards, with the intent that later IEEE 1547.1 through .8 standards be used in conjunction with standard IEEE 1547. The evolving series of IEEE 1547 standards include IEEE subgroups currently developing guidance and recommended practices: a) to determine the appropriate criteria, scope and extent of distribution impact studies for distributed resource interconnections, and b) to address changes to the current standard to accommodate high penetrations of intermittent generators. These will be standards 1547.7 and 1547.8 respectively. Although this work will undoubtedly inform future modifications to state and federal interconnection processes, there is much in the way of screening and processing of interconnection applications that IEEE standards do not address.

A notable limitation of the 1547 standard is that it does not address technical considerations defining the maximum allowable amount of generation beyond the point of common coupling—the point at which one generating facility is physically interconnected to the utility electric power system.[15] Standard IEEE 1547 does not address operations and impacts upstream or downstream from that point. In addition, it does not address non-technical issues such as the timeframe or cost of interconnection..

These issues are left to the determination of regulators in the development of interconnection processes and other valuations.

May 2005: FERC Small Generator Interconnection Procedures

In 2005, the Federal Energy Regulatory Commission (FERC) adopted Small Generator Interconnection Procedures (SGIP) and a corresponding Small Generator Interconnection Agreement (SGIA).[16] The SGIP and SGIA are based on FERC's Large Generator Interconnection Procedures and Agreement, but apply to generating facilities of 20 Megawatts (MW) in capacity or less.[17]

The FERC SGIP was vetted by a broad range of industry participants and adopted through FERC Order 2006 in May 2005, and Orders 2006-A and 2006-B in the subsequent year.[18] The SGIP and SGIA apply to FERC jurisdictional interconnections, including facilities that a) interconnect to FERC-jurisdictional transmission systems, or b) interconnect to FERC-jurisdictional distribution systems to sell wholesale generation in interstate commerce (e.g. a wholesale generator is already interconnected with the specific distribution line and the distribution line is covered by a FERC-approved Open Access Transmission Tariff).

SGIP includes three levels of review: Level 1 is a simplified screening process for certified inverter-based systems less than 10 kilowatt (kW); Level 2 is a "Fast Track Process," for eligible generators no larger than 2 MW; Level 3 is a "Study Process" for all other systems 20 MW or less. SGIP applies ten interconnection screens for the first two review levels, including the previously noted screen that requires an interconnection study for generators that cause aggregate generation capacity to exceed 15% of annual peak load on a line section of a radial distribution circuit.

SGIP was developed both to govern FERC-jurisdictional interconnections and to serve as a model that state regulators may use as a starting point for developing their own interconnection procedures and agreement.[19]

August 2005: Energy Policy Act of 2005

A survey in 2000 by NREL found that virtually all distributed-generation projects met some sort of resistance from utilities when they try to interconnect with the grid.[20] Partly in response to that finding, Congress included Section 1254 in the Energy Policy Act of 2005 (EPAct '05), which required state regulatory commissions and certain non-regulated utilities to consider adopting interconnection procedures based on the IEEE 1547 Standard and current "best practices."[21]

At least 31 states adopted or amended their interconnection processes in some form or another in the years following the enactment of EPAct '05.[22] Many of these states modeled their interconnection policies on FERC's SGIP. A few Western states modeled their procedures on California's Rule 21.[23] It is not clear whether these policies were adopted as a result of federal law. It is evident, however, that EPAct '05 had a significant impact by raising awareness about interconnection issues and by spurring dialogue at a state regulatory level. As of August 2012, 43 states plus the District of Columbia and Puerto Rico had adopted interconnection policies.[24]

2. INTERCONNECTION NEEDS GOING FORWARD

Many key steps in the development of standard interconnection processes for small generators occurred prior to 2006. As the U.S. market for solar PV technologies and small renewable generators has diversified and expanded in recent years, it has become increasingly important to reevaluate and update existing interconnection processes to properly accommodate and encourage this growth now and into the future without compromising the safe and reliable operation of the nation's electric power systems.

The growth and expansion in the solar market has largely been a result of the widespread adoption of state Renewable Portfolio Standards (RPS) over the last decade. Most of the country's 30 RPS policies have been established or considerably expanded since 2005,[25] and 17 of these policies include a solar or DG carve-out.[26] Available data shows that by 2010, national RPS obligations extended to half of the retail electric load consumed in the United States[27] and required utilities to generate or purchase close to 100 million Megawatt hours (MWh) of renewable and alternative energy generation.[28]

To meet new demands for solar energy generation, state policies have expanded traditional mechanisms that supported smaller customer-owned installations, such as residential rooftop PV, to include larger systems that supply multiple customers. For example, since 2005, community solar programs have emerged in at least 15 states.[29] Definitions of community solar vary from state to state, and even from project to project, but generally speaking, community solar programs allow multiple customers to receive benefit from, or assume shared ownership of, a single solar system. Most community solar installations have been large, ground-mount systems, with little or no onsite load being served.

Solar policies have also expanded to include wholesale programs designed to encourage power exports to the electric power system. These wholesale generators may serve little or no onsite load. Wholesale policies aimed at DG have expanded rapidly over the past five years and include feed-in tariffs (FIT), auction mechanisms, and competitive solicitations. By 2010, 7 of the top 10 states for installed solar capacity had one or more types of wholesale DG programs.[30] In the last few years alone, California has authorized almost 3 gigawatts (GW) of DG procurement programs, mostly through requests for proposals, auctions, and FIT programs.[31]

As a result of the growth in DG procurement programs, many utilities across the nation have experienced an increasingly high volume of interconnection applications, both for large and small generators. In 2005, only 79 MW of grid-connected PV capacity was installed across the United States. Five years later, the grid-connected solar PV capacity installed in just one year totaled 878 MW,[32] over ten times the cumulative amount installed just five years earlier and double the capacity that had been installed the prior year. Annual grid-connected PV capacity more than doubled again in 2011 to 1,845 MW (see Figure 1 below), which brought the grid-connected PV capacity in the United States to 4,000 MW by the end of that year.[33] That is a 500% increase in 7 years.

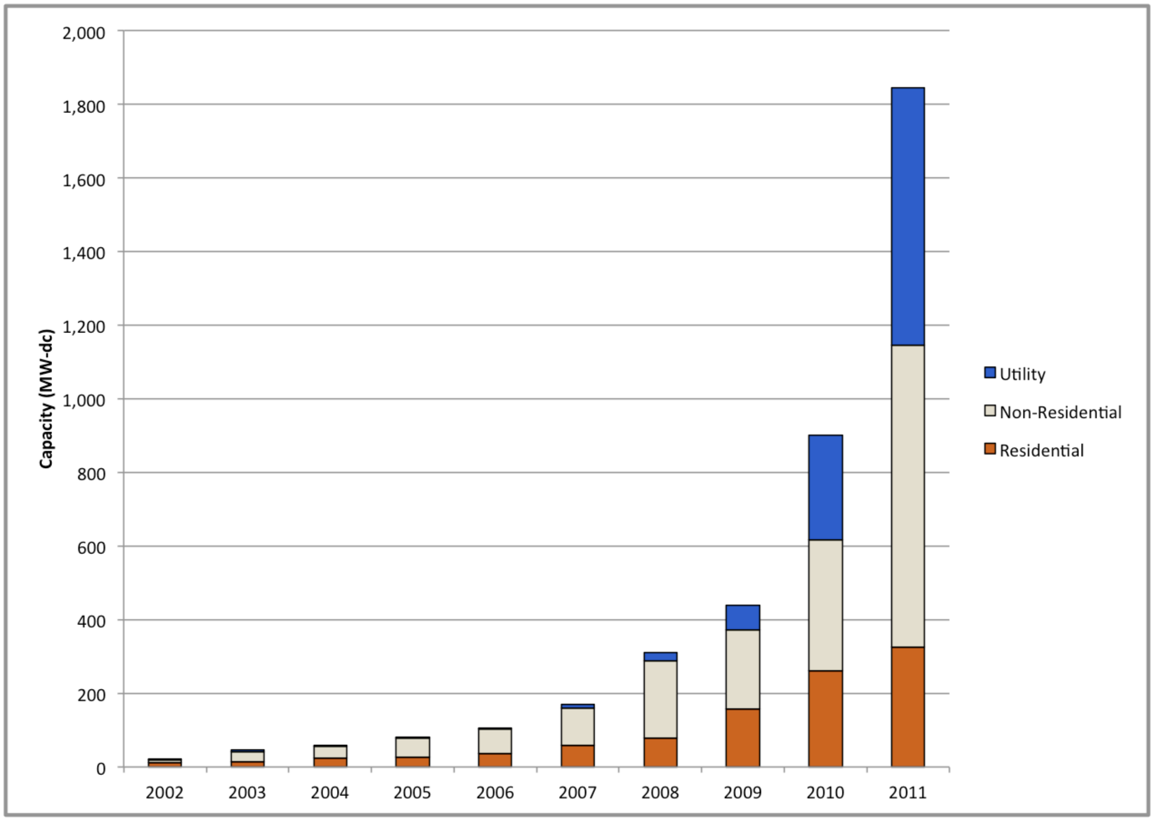

Figure 1. Annual Installed Grid-Connected PV Capacity

Solar Electric Power Association (SEPA)'s 2011 Utility Solar Rankings report describes the incredible undertaking this can mean, particularly for utilities in the top solar states:

> "Utilities are adapting to solar as their fastest growing electricity source. In 2011, utilities interconnected over 62,500 PV systems, 89% of which were residential homes, and which was a 38% growth over 2010. Thirteen utilities interconnected more than 1,000 PV systems and 22 interconnected more than 500 systems. To put this in perspective, about 350 non-solar power plants (> 1 MW) were expected across the entire U.S. in 2011. This annual volume of smaller, distributed solar interconnections is unlike anything the utility industry has previously managed, and conservative forecasts indicate that this number will grow to more than 150,000 interconnections in 2015."[34]

Although dramatic, the installed-capacity figures for solar PV do not fully convey the total number of interconnection applications being received by utilities in states with robust renewable energy policy requirements. Many interconnection applications do not lead to installed capacity because the applicants abandon project development after learning that expensive upgrades may be needed. Thus, the number of interconnection applications—and the work associated with every interconnection application—can greatly exceed both the total installed capacity and the number of systems that are ultimately interconnected. For example, the California Independent System Operator claims its queue has four times the amount of new generating capacity than is necessary to meet California's 33% RPS goal, and it expects 75% of projects currently in the queue will not be completed.[35]

As the amount of installed PV and DG capacity has increased, utilities have begun to experience high penetrations of PV on areas of their distribution systems. Continued rapid growth in solar and DG markets will inevitably result in more areas with a high penetration of DG resources. There is no technical consensus on the percentage of DG resources that defines high penetration on a given utility distribution feeder. Moreover, the impact of DG on the distribution system varies according to factors such as a) the type of resource, b) the expected performance of the resource, c) the usage patterns of customers on the distribution feeder, and d) the location of the DG on the feeder.

From an engineering perspective, a circuit has reached "high penetration" when utility engineers determine that upgrades need to be made to the circuit before additional generation can be installed. There are no absolute technical limits to grid penetration. However, many utilities and research organizations around the country have begun studying the impact that high-penetration PV is having, or may have, on electric power systems in their regions.[36] For example, Hawaii's Kauai Island Utility Cooperative has been testing a 1.2 MW PV project that supplies up to 90% of a distribution circuit's demand and has not experienced any disruption to the overall power quality on that circuit.[37] This is an important preliminary finding, given that Hawaii has an RPS mandate to achieve 40% renewable energy by 2030—the most ambitious in the country.[38]

Although most utilities do not publish information about penetration levels on their distribution feeders, it is clear that several regions of the country are already experiencing high penetration due to the sheer volume and concentration of DG that has interconnected or is requesting interconnection. In SEPA's 2011 Utility Solar Rankings report, the authors noted that, "[t]he nation's most solar active utilities integrated almost 1,500 megawatts (MW-ac) of new solar, equivalent to six natural gas power plants…"[39]

It is also clear that these high penetration solar regions have expanded beyond just California and are now moving into Eastern states. In 2008, 93% of the nation's total annual solar capacity was installed in the Western region. By 2011, however, Western states held only 61% of the nation's annual installed solar capacity,[40] and only two California utilities were among the top ten for Cumulative Solar Watts-per-Customer (see Figure 2 below).[41]

2011	2010	Utility	Watts (AC)
1	Not Ranked	Vineland Municipal Electric (NJ)	991.2
2	5	Maui Electric Co. (HI)	209.3
3	66	Blue Ridge Mountain EMC (GA)	194.7
4	11	Atlantic City Electric (NJ)	185
5	2	Kauai Island Utility Co-op (HI)	179.1
6	18	Arizona Public Service - APS (AZ)	176.3
7	1	Southern California Edison (CA)	151.9
8	117	Fayetteville Public Utilities (TN)	150.1
9	9	Hawaiian Electric Co. (HI)	148.5
10	6	Pacific Gas & Electric (CA)	146.2

Figure 2. 2011 Cumulative Solar Watts-per-Customer

As U.S. and individual state energy needs grow and evolve, it has become increasingly important for regulators to revisit and update interconnection procedures to ensure they remain adequate in the face of a dynamic and growing market. In 2011, the California Public Utilities Commission (CPUC) opened a rulemaking to re-examine California's Rule 21 interconnection procedures in light of changed market conditions, stating:

> "…when a generator seeks to primarily offset on-site load, interconnection under the existing Rule 21 generally occurs efficiently. In contrast, generators seeking to export a portion or all of their generation to the utility's distribution system lack a straightforward means of interconnection under the effective Rule 21. Exporting generators eligible to use Rule 21 as the interconnection tariff include those participating in a number of procurement programs administered by the Commission, including the renewable feed-in tariff, the efficient combined heat and power feed-in tariff and Qualifying Facilities up to 20 megawatts."[42]

Several other states such as Hawaii, Massachusetts, and New Jersey have engaged in similar interconnection reform processes. Many of the reforms being considered are an attempt to accommodate the influx of interconnection applications being filed by participants in programs implemented to meet state policy goals. In Hawaii, a multi-party stakeholder process convened from 2010 to 2011 produced a broad range of recommendations to reform Hawaii's Rule 14H interconnection process. Likewise, the CPUC-initiated rulemaking from 2011 led to a broadly-supported proposal put forth by a range of parties, including California's three largest investor-owned utilities, to significantly overhaul the California Rule 21 interconnection process. Efforts to reform state interconnection processes in Massachusetts and New Jersey were ongoing as of this publication. Not surprisingly, these states have a diverse and rapidly-growing solar market and have experienced the most pressing need to address interconnection reform.

3. DISCUSSION OF POSSIBLE SGIP MODIFICATIONS

With the exception of the handful of states and utilities that have recently updated their interconnection processes, most existing interconnection processes were implemented prior to significant changes in the solar market that have occurred over the last seven years, and were designed for lower penetrations that are increasingly being reached.

The FERC SGIP process and the state processes modeled after SGIP provide a reasonably cost-effective and efficient process for small DG at penetrations up to 15% of peak load on a distribution feeder. However, the SGIP process becomes more expensive, time consuming, and less certain once that penetration level is reached. In many parts of the country, this penetration has been reached, and the *Interconnection Screens Report* notes that the lack of a well-defined process for interconnecting generators to the distribution system at higher penetrations has become a barrier to continued PV system deployment.[43] Some developers have claimed that some utilities are closing feeders to new interconnections after 15% of peak load penetration is reached.[44]

Interconnection procedures must be updated if they are to continue to provide an efficient and cost-effective process for interconnecting small generators. A well-designed interconnection process allows utilities to maintain the safety and reliability of the electric power system while providing a transparent, efficient, and cost-effective process that operates on predictable timeframes. Such a process can lower the cost of developing new generating capacity, facilitate market entry by smaller generators, increase wholesale market competition, and encourage investment in needed infrastructure.

SGIP has been an influential interconnection model in the United States. It has been incorporated into the tariffs of FERC-jurisdictional utilities and therefore has a foothold in nearly every state within the continental United States. Also, many states have used SGIP as a template for the development of their state interconnection processes. SGIP's three levels of review were incorporated into interconnection procedures in numerous states across the U.S. including, but not limited to, Colorado, Connecticut, Florida, Indiana, Maine, Michigan, Oregon, New Jersey, New Mexico, New York, North Carolina, Ohio, Utah, and Virginia.[45] Many states also use screens that are based on, or are very similar to, those used in the SGIP Fast Track.[46]

Because SGIP has been widely adopted and very influential, it is an appropriate focus for a discussion about interconnection reform in this report. In light of significant changes in the marketplace over the last six years, modifications to SGIP and the state processes modeled on SGIP will help ensure the interconnection process remains relevant in the face of a rapidly-evolving marketplace and will ensure continued open access for small generators. Updates to SGIP will also ensure that SGIP continues to serve as a relevant model for state policymakers to use in updating state interconnection processes.

The following sections examine key components of the SGIP process and discuss potential improvements and/or areas that warrant further study to respond to the increased volume and high-penetration scenarios discussed above. The "Pre-application Information" section discusses the information presently available to an applicant prior to submitting an interconnection request, and possible ways to increase access to relevant information to enable applicants to pre-screen suitable locations. This information would, in turn, reduce the number of applications utilities may need to process for projects in locations that are not likely to be financially viable.

The subsequent three sections focus on the three levels of SGIP review: the Level 1 10 kW Inverter Process, the Level 2 Fast Track process for generators 2 MW or less, and the Level 3 full Study Process for all other generators up to 20 MW in capacity. These sections highlight areas of SGIP that may be creating inefficiencies in the interconnection process or provide inadequate screening for potential technical issues. Where possible, each of these sections discusses modifications that have been approved by FERC or state regulatory agencies.

PRE-APPLICATION INFORMATION

As markets for solar PV and DG grow, utilities are increasingly being faced with lengthy interconnection queues. However, a significant number of projects in the queue drop out after they receive study and/or Fast Track results, or other conditions make it apparent that a proposed interconnection is not economically viable. The number of dropouts is likely to increase as higher penetrations are reached and fewer generators are able to interconnect without triggering expensive upgrades.

One method to avoid interconnection queues being clogged with projects that may ultimately prove unviable is to provide potential applicants with additional information about system conditions at a proposed point of interconnection in advance of an application being submitted. If applicants have access to additional utility-supplied information, they may be able to avoid filing speculative interconnection requests and can relieve some of congestion in utility interconnection queues. Additional information may also facilitate more efficient use of the existing electric power system by helping identify areas with available capacity where interconnections may proceed at lower cost with no or few upgrades.

SGIP Section 1.2 currently provides potential applicants with the option of requesting information on the electric system at a proposed point of interconnection:

> "Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Transmission Provider's Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements."

However, Section 1.2 does not provide a timeframe for when information must be provided in response to a request or the level of detail about a proposed point of interconnection that a potential applicant can expect to receive.

California has taken two important steps in providing additional information about proposed points of interconnection to potential applicants. First, as part of revisions to

California Rule 21, a pre-application report would allow developers to request specific system information about a proposed point of interconnection for a $300 fee.[47] A developer must provide sufficient information to clearly identify the proposed point of interconnection. Once a request is received, a utility must provide the information within 10 business days of a request. The type of information that Rule 21 requires utilities to provide, where available, includes total, queued, and available circuit capacity, line voltage, distance of proposed point of interconnection to substation, peak and minimum load data, and, number of phases available at site.[48]

The revisions to California Rule 21 only require a utility to provide pre-existing information, meaning the utility is not required to conduct any new analysis in order to respond to a request. The information provided is also understood to be subject to change prior to an application being submitted. Conditions on the electric power system are dynamic, and thus the information provided may be outdated by the time an application is submitted.

In addition to the pre-application report, the CPUC has required utilities to publish maps of their distribution systems that identify areas with capacity available. Hawaii has taken a similar approach in providing information via online maps on the penetration levels that have been reached on distribution circuits. These maps enable developers to screen wider areas for potentially good locations for interconnection. Though they do not provide sufficient detail to accurately predict the outcome of application of the Fast Track screens, they provide a useful initial screening tool. These maps may also help the utilities reduce the number of specific information requests to which they may need to respond.

The pre-application provision in SGIP currently allows for the exchange of relevant information, but does not provide specific timeframes, or allow utilities to be compensated for time spent preparing information, or provide applicants with certainty as to what information will be made available. In order to reduce the number of speculative applications and increase the efficiency of the interconnection study process for potential applicants, SGIP section 1.2 could be modified to include greater specificity.

Below, we have provided a possible modification to SGIP Section 1.2 modeled on California Rule 21 revisions:

1.2.2 In addition to the information described in Section 1.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal request along with a non-refundable processing fee of $300 for a pre-application report on a proposed project at a specific site. The Transmission Provider shall provide the pre-application data described in Section 1.2.3 to the Interconnection Customer within 10 Business Days of receipt of the written request and payment of the $300 processing fee.

1.2.3 Subject to Section 1.2.4, the pre-application report will include the following information:

a. Total capacity (in MW) of substation/area bus, bank, or circuit based on normal or operating ratings likely to serve proposed site.

b. Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank, or circuit (i.e., amount of generation online) likely to serve proposed site.

c. Aggregate queued generation capacity (in MW) for a substation/area bus, bank, or circuit (i.e., amount of generation in the queue) likely to serve proposed site.

d. Available capacity (in MW) of substation/area bus or bank and circuit most likely to serve proposed site (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

e. Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

f. Nominal distribution circuit voltage at the proposed site.

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

h. Relevant line section(s) peak load estimate, and minimum load data, when available.

i. Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed site and the substation/area. Identify whether substation has a load tap changer.

j. Number of phases available at the site.

k. Limiting conductor ratings from proposed point of interconnection to distribution substation.

l. 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.

1.2.4 The pre-application report need only include pre-existing data. A pre-application report request does not obligate the Transmission Provider to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Transmission Provider cannot complete all or some of a pre-application report due to lack of available data, the Transmission Provider shall provide Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on “available capacity” does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of submission of the complete Interconnection Request.

LEVEL 1 (10 KW INVERTER PROCESS) – POSSIBLE MODIFICATIONS

The 10 kW Inverter Process uses the Level 2 Fast Track technical screens to evaluate the safety and reliability of a proposed interconnection (see discussion on Level 2 below), but it allows qualified generators to use a shorter application that integrates an interconnection agreement.[49] This process allows a utility reviewing an application to execute and return an interconnection agreement to the customer quickly, after initial review is complete and all the Fast Track screens are passed. FERC intended the 10 kW Inverter Process to be "quick, inexpensive, and user friendly"[50] and this proposal supports those goals.

A number of states have adopted modifications to the 10 kW Inverter Process that improve the efficiency of review for very small generators. These changes are discussed below.

Possible Modification: Increase Eligible System Sizes

The SGIP 10 kW Inverter Process is intended for generators that are unlikely to trigger adverse system impacts. Inverter-based equipment has a lower likelihood of causing adverse system impacts because such equipment can quickly disconnect when a disturbance occurs.[51] Despite a reduced likelihood of adverse impacts, this process requires the same amount of technical screening as is given to generators up to 2 MW participating in Fast Track. The primary benefits of the 10 kW Inverter Process are the reduced cost and ability to submit a relatively short, combined application and interconnection agreement. These benefits accrue to both a) customers installing small, inverter-based systems, and b) utilities through the reduction in administrative time spent processing a separate interconnection agreement.

Many states feature a 10 kW Inverter Process or "Simplified" interconnection option for very small generators similar to SGIP. For example, New Mexico,[52] Pennsylvania[53] and Florida[54] provide simplified processes for systems 10 kW or less. Other states have expanded the quick, inexpensive, and user-friendly aspect of the 10 kW Inverter Process to systems of larger sizes. For example, Oregon provides a simplified process for inverter-based systems 25 kW or less that are UL 1741 certified.[55] In Oregon's case, the residential net metering eligibility limit is also 25 kW, meaning residential customers installing net-metered generation have a highly efficient interconnection path. Massachusetts provides a simplified review for systems up to 25 kW, so long as they are interconnecting using a three-phase service and meet other conditions.[56]

At the time SGIP was first adopted, most residential PV systems were well under 10 kW, but as the market has grown, so has the size of the average PV installation. Recent data shows that the size of residential systems, which still make up the bulk of the PV systems installed in the U.S., is 5.7 kW_{DC}.[57] Although the size of an average residential system is still less than 10 kW, many state programs allow for generators larger than 10 kW to net-meter. As the volume of residential interconnection applications increases, it makes sense to ensure continued administrative ease in the interconnection of these generators.

Because all generators that interconnect under the 10 kW Inverter Process are subject to the Fast Track screens, increasing eligibility above 10 kW will not reduce the screening applied to a generator for safety, reliability, and power quality issues. As the state examples demonstrate, it is unlikely that utilities need a more complicated application form or interconnection agreement for generators up to 25 kW, and possibly even larger generators. Thus, it may be reasonable to extend this process to a greater number of residential and small commercial systems by increasing the size limit of generators eligible for the Fast Track screens to 25 kW in order to reduce administrative burdens for both applicants and utilities.

To effectuate an increase in the 10 kW Inverter Process to accommodate generators up to 25 kW, references in SGIP and similar state procedures to "10 kW Inverter Process" can be replaced with "25 kW Inverter Process".

Possible Modification: Shorten Processing Timelines

The SGIP 10 kW Inverter Process follows the Level 2 Fast Track timelines. A utility is presently required to notify a customer that an application is complete within 10 business days from the date of submission, and the time to complete the initial technical review screens is 15 business days from time an application is deemed complete.

Several states have shortened timelines that apply to interconnection of very small generators. The states in Table 1 have adopted either 1) shorter timeframes for notifying a customer that an interconnection application is complete, or 2) the time to complete initial review.

Table 1. States with Fast Track Timelines Shorter than SGIP

State/Rule	Time to Notify Customer that Application is Complete	Time to Complete Initial Review
SGIP 10 kW Inverter Process	10	15
Maryland	5	15
New Jersey (PSE&G Tariff)	3	10
Massachusetts Interconnection Document	3	10

As the examples in Table 1 illustrate, a 10 kW interconnection request can be processed more quickly than is currently required in the SGIP. In addition, several states have established a default approval mechanism so that simplified interconnection requests will be deemed approved unless an applicant is notified otherwise. Vermont and Virginia both have provisions that "deem" an interconnection request approved for very small net metering generators when initial review has not been completed within the required timeframes. A recent Vermont law provides for automatic approval for net-metered generators 10 kW or less after 10 days, so long as a customer completes registration and certification of compliance and a utility does not deliver a letter to the customer detailing any issues concerning the interconnection.[58] In Virginia, net-metered generators 25 kW or less are deemed to be approved for interconnection unless a utility notifies a customer within 30 days.[59]

An advantage of the Vermont and Virginia approaches is that interconnection customers have a higher degree of certainty on the maximum time it will take to receive an approved interconnect. Incorporating a deemed-approval process into SGIP for the smallest inverter-based systems would help ensure that the interconnection of these generators may be processed in predictable timeframes. With the potential for "plug-and-play" solar PV systems to be brought to market through mainstream retailers, the processing of interconnection requests for very small inverter-based generators will need to be routine.

To increase the efficiency of processing interconnection applications, the 10 kW Inverter Process could be shortened to confirm that a customer's application is complete 3 business days after receipt. This would achieve a significant reduction in the time it takes an interconnection customer to interconnect using the Inverter Process as opposed to the standard Fast Track Process. In addition, an automatic approval process may be worth considering as well.

Proposed Redline of SGIP § 1.3 (insert the following after the fourth sentence of § 1.3)

1.3 Interconnection Request

[. . .] If the Interconnection Customer is applying electronically using the 25 kW Inverter Process Application and Agreement, the Transmission Provider shall notify the Interconnection Customer within three Business Days of the receipt of the Interconnect Request as to whether the Interconnection Request is complete or incomplete. For all other Interconnection Requests, the Transmission Provider shall notify the Interconnection Customer within ten Business Days of the receipt of the Interconnection Request as to whether the Interconnection Request is complete or incomplete. [. . .]

Possible Modification: Online Application and Electronic Signatures

Order 2006 envisioned a combined interconnection application and agreement (SGIP Attachment 5) as "eliminat[ing] the additional step of signing an interconnection agreement if the proposed interconnection passes the screens."[60] A combined application and agreement has been adopted in a number of states, and several states and utilities have simplified things further by moving to an online interconnection application. This reflects the general advance and acceptance to conduct more business online since the time Order 2006 was issued.

In California, both San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE) feature online applications for interconnections of small net-metered systems.

SDG&E allows net-metered systems up to 30 kW to complete an application and agreement through an online portal.[61] SCE offers online submittal of a simplified interconnection application for net metered generators via a Microsoft Excel spreadsheet that can be filled out and emailed directly to the utility's interconnection department.[62]

Online applications are efficient because they shorten the time it would take for a utility to process a complete interconnection request. They can also help to quickly identify deficiencies in an application, for both the applicant as well as the utility. In addition, online applications create an electronic trail that increases accountability. For example, Con Edison's general online document management system allows its customers in New York to confirm receipt of their application and associated documents and track major milestones in the process.[63] In addition to Con Edison, Pepco (Maryland), PSE&G (New Jersey), and National Grid (Massachusetts) feature an online application form for simplified interconnection that can be filled out and transmitted to the utility via email.

Incorporation of an online interconnection application into SGIP could increase the efficiency of interconnection and reduce mistakes and the number of incomplete applications without undermining or affecting the integrity of the review process. Following are possible redlines to incorporate the option of an electronic application submittal process.

Proposed Redline of Attachment 5 (Section 1.0 and 2.0 on p. 1):

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider ("Company"), by mail, email or online via the Transmission Provider's website.

2.0 If submitted electronically, the Company acknowledges receipt of the Application by creating an automatic email confirmation number and email transmission to the Interconnection Customer. If not submitted electronically, the Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.

The time to process a simplified application is also affected by the requirement that a "wet" signature be included on an application. To effectuate the move to an electronic submittal method, as proposed above, SGIP could be modified to allow for electronic signatures. The standard 10 kW Inverter Process application form currently requires an interconnection customer to physically sign and mail an application.

Electronic signatures are generally recognized in commercial activities, and 47 states have adopted the substance of the Uniform Electronic Transaction Act (UETA), a model act developed by the National Conference of Commissioners on Uniform State Laws.[64] Accordingly, revisions to the 10 kW Inverter Process Application and Agreement form to allow use of electronic signatures could further streamline the administrative process for small generators without any detriment to safety, reliability or power quality. Although a utility may be concerned that there is a lack of verification when a customer submits an application without a signature, SCE's approach, which allows a customer to attach a digital copy of the customer's electric bill to the application, may be one means to provide identity verification.[65]

Below are proposed modifications to SGIP that would incorporate the option for electronic signatures of the 10 kW Inverter Application.

Proposed Redline of SGIP Attachment 5 [p.4]

> Interconnection Customer Electronic Signature
>
> By submitting this document, which includes electronic submission, 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 Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

LEVEL 2 (FAST TRACK PROCESS) – POSSIBLE MODIFICATIONS

Fast Track consists of an initial review and, if necessary, a supplemental review. Initial review applies 10 technical screens that FERC intended to identify "proposed interconnections that clearly would not jeopardize the safety and reliability of the Transmission Provider's electric system."[66] FERC's use of "clearly" indicates that these screens were intended to allow interconnection without study in situations in which there is not a "close call" regarding possible impacts to safety, reliability, and power quality. Passage of these screens provides an expedited path to interconnection without additional study.[67] Supplemental Review serves as a second chance for generators that fail one or more of the initial review screens, providing the utility an opportunity to determine that a generator may nevertheless be interconnected consistent without unacceptable impacts to safety, reliability, or power quality.[68]

Several of the Fast Track screens may not be optimally designed to facilitate the rapid growth of solar PV and increasingly higher penetrations of DG. Although publicly available information on technical screen failure rates is limited, the information that exists shows that Fast Track failure in high-penetration markets is predominantly caused by SGIP Screen 2, which limits aggregate capacity on a line section to 15% of peak load.[69] High failure rates have also been found for Screen 9, which evaluates transmission impacts, and Screen 10, which fails projects needing any construction or upgrades on the utility system. Below, we discuss possible modifications to these screens as well as the Fast Track eligibility limit.

Possible Modification: Fast Track Eligibility

Before beginning the Fast Track screening process, a proposed generator must meet the eligibility criteria set out in SGIP section 2.1, which requires that a generator be "no larger than 2 MW" and meet "the codes, standards, and certification requirements" established in SGIP Attachments 3 and 4.[70] With a growing number of state policies facilitating an expansion of DG larger than 2 MW, there are an increasing number of generators seeking interconnection that exceed the 2 MW limit. Requiring all of these generators to proceed through a detailed study process may prove costly and resource-intensive. So, whether a size limit is appropriate, or even necessary, has come under increasing scrutiny in state and federal forums.

The 2 MW size limit for Fast Track was first adopted by FERC in Order 2006. In Order 2006, FERC rejected the argument that Fast Track should have no size limit, stating that it was adopting the 2 MW threshold "as a critical eligibility criterion for using the screens" because "[i]t helps ensure the safety and reliability of the Transmission Provider's electric system."[71] FERC did not elaborate on the specific safety and reliability issues the 2 MW eligibility limit was intended to address. Thus, the 2 MW limit may best be viewed as a proxy for the generator size, above which safety and reliability impacts were believed to potentially give rise to the need for a full study of interconnection impacts.

Despite FERC's statements in Order 2006, FERC has since approved deviations for specific utilities. In 2011, FERC approved an increase to 5 MWs for generators connecting to the California Independent System Operator (CAISO) transmission system.[72] Following FERC's approval of modifications to the CAISO Fast Track eligibility limit, SCE and Pacific Gas & Electric (PG&E) sought modifications to their FERC-approved Wholesale Distribution Access Tariffs (WDAT).[73] SCE chose to retain the 2 MW limit,[74] but PG&E kept the Fast Track eligibility of 2 MW on a 12kV interconnection and raised the eligibility to 3 MW on a 21 kV interconnection and 5 MW for interconnections at higher voltages.[75] FERC deferred to the utilities' chosen size limits, respecting SCE's argument that differences in its system prevented it from moving to the higher size limit chosen by PG&E.[76]

State procedures typically use one of three approaches in determining eligibility for Fast Track review. The majority of states mirror the SGIP size limit of 2 MW.[77] A number of state interconnection procedures limit their applicability to the size of the local net metering eligibility limit, which is generally no larger than 2 MW.[78] Finally, a handful of states, particularly those that based their interconnection standards on the former California Rule 21, do not limit the size of systems eligible for Fast Track.[79]

Although California Rule 21 did not have a size threshold for a number of years, recent modifications to California's Rule 21 introduce the following size thresholds on Fast Track eligibility:

> "Non-Exporting and Net Energy Metered Generating Facilities are eligible for Fast Track evaluation regardless of the Gross Nameplate Rating of the proposed Generating Facility. Exporting Generating Facilities with a Gross Nameplate Rating no larger than 3.0 MWs on a 12 kV, 16 kV or 33 kV interconnection for Southern California Edison, 1.5 MW on a 12 kV interconnection for San Diego Gas & Electric, and 3.0 MW on a 12 kV or higher interconnection for PG&E are also eligible for Fast Track evaluation."[80]

Although there is no clear technical justification for setting Fast Track eligibility at any particular level, establishing a size threshold can serve both a technical and process-oriented function. Generator size is a critical factor in determining whether a generator may have potential impacts on the distribution and/or transmission system. The larger a generator, the more likely it is to fail one or more of the Fast Track screens and require Supplemental Review or detailed study. Establishing a reasonable threshold provides transparency regarding the timeframe likely to interconnect, and it helps ensure that generator interconnections that may pose impacts on safety or reliability may be studied so a utility has an opportunity to determine the requirements necessary to mitigate those impacts.

Another purpose of a size limit is to reduce the number of generators that are needlessly run through the Fast Track screens if they are almost certainly going to require further study. In light of the increasing number of interconnection requests, the cap can set realistic expectations about the speed with which interconnection can proceed for larger generators. A size limit also relieves utilities of the burden of processing a high volume of applications through Fast Track that have little chance of interconnecting through that process. The cap may thus reduce tension between utilities and applicants and result in a more efficient interconnection process.

This does not, however, answer the question of whether 2 MW remains an appropriate threshold for Fast Track eligibility. As noted above, recent tariff modifications in California suggest it may be reasonable to vary the limit based on relevant technical considerations at the point of interconnection, such as the capacity of the distribution line to which a generator seeks to interconnect.[81] In addition to voltage of the distribution line, there may be other relevant factors to consider in setting a limit, including whether a generator is located on a network or radial distribution circuit and how far a generator is located from a utility substation.

This discussion suggests that it may be valuable to consider whether the size limit could be set in a more nuanced manner that takes into account system conditions at the point of interconnection. For example, generating facilities located close to a substation and on a main distribution line are less likely to raise impacts that may require study than generating facilities located at the end of a long distribution line. Table 2 provides an example of how these considerations could be integrated into a more nuanced Fast Track eligibility approach.

Table 2. Fast Track Eligibility

Line capacity	Fast Track Eligibility- regardless of location	Fast Track Eligibility- on > 600 amp line and < 2.5 miles from substation
< 4kV	< 1MW	< 2 MW
5kV – 14 kV	< 2MW	< 3 MW
15 kV – 30 kV	< 3MW	< 4 MW
31 kV – 60 kV	< 4MW	< 5 MW

Possible Modification: SGIP Screen 2 – Penetration Screen

SGIP, and the vast majority of state interconnection procedures, screen Fast Track applicants in part by looking at the penetration level of distributed generation interconnected to the nearby distribution system. Specifically, Screen 2 of SGIP asks whether a generator will cause aggregate generation to exceed 15% of the line section's annual peak load.[82] With increased penetrations of distributed generation and larger generators seeking to interconnect, this screen is more likely to be failed.[83] An evaluation of whether the screen is set at the appropriate level, and whether there are alternate methods of assuring system safety and reliability at higher penetrations without requiring detailed studies may be appropriate to respond to changed conditions.

The penetration screen was first established in California's Rule 21 to address the possibility that operating requirements may be different for generators at higher penetrations and therefore may require additional study to safely interconnect.[84] As penetration increases, the risk of "unintentional islanding, voltage deviations, protection miscoordination, and other potentially negative impacts" may increase.[85] These risks become more significant when there is a possibility that generation will exceed minimum load on a circuit or when distances from the substation grows.

At the time Screen 2 was created, few utilities were collecting minimum load data for most circuits, thus the 15% of peak load measurement was identified "as a surrogate for knowing the actual minimum load on a line section."[86] The *California Interconnection Guidebook* explains: "A typical line section minimum load is at least 30% of the peak load, therefore at 15% aggregate, the generating capacity would be no more than 50% of the minimum load of the Line Section."[87]

It is still true that utilities do not consistently have minimum load data for all circuits, however as more utilities install Supervisory Control and Data Acquisition (SCADA) systems and roll-out smart grid features there is an increasing amount of data available. In addition, the *Interconnection Screens Report* concludes that "minimum load can be estimated based on standard load profiles for various customer classes that many utilities maintain and update on an annual basis."[88] Other methods are also available for calculating or estimating minimum load that may be similar to methods used for determining peak load levels of line sections. Use of an equivalent minimum load measurement may enable a greater number of generators to interconnect without study on certain circuits, but on other circuits, such as those with highly seasonal load patterns, use of minimum load may reduce the number of generators that can connect without study.

Some states have incorporated minimum load screening into their interconnection procedures. Montana's interconnection procedures require total generation capacity to be below 15% of peak load screen *or* "the annual minimum load of the line section."[89] In Arizona, model interconnection procedures developed by stakeholders state that aggregate generation must be below 15% of peak load, and "must also be less than 50 percent of the minimum daytime feeder or line section load, where these data are available, unless the minimum load is zero."[90]

These states have modified initial review screens to evaluate minimum load where data exists or can be calculated. According to the *California Interconnection Guidebook* the equivalent to 15% of peak load would be 50% of minimum load, although a less conservative minimum load level could also be considered (i.e. 75% or 100% of minimum load). Montana appears to use 100% of minimum load.

Rather than modifying the 15% screen in the initial review process, utilities in Hawaii and California recently agreed to incorporate a minimum load threshold into Supplemental Review processes of their respective state procedures. In both states, if a generator fails the 15% of peak load screen, it will be required to undergo Supplemental Review. In Hawaii, Rule 14H then specifies that if "the aggregate generating capacity per Line Section is no greater than 50% of the Line Section minimum kW load during the period when the proposed generation is available (including noon on Sunday for solar photovoltaic systems)," a generator will be allowed to interconnect without detailed study.[91] Under procedures in California, if it is determined that the generating capacity is less than 100% of minimum load on a line section a generator may be allowed to interconnect without detailed study if two additional supplemental review screens determine the interconnection does not raise potential power quality, voltage, safety, or reliability concerns that require detailed study.[92] If the generating capacity exceeds 100% of minimum load, the generator will likely require detailed study.

Data regarding minimum and peak loads on a circuit are necessarily based on historic levels combined with reasonable forecasts for growth or diminishment of load. These estimates are no guarantee of future load levels, however, as load can shift with changes in the economy, investments in energy efficiency, and other conditions outside of the utility's control. Minimum load can also change as a result of distribution system reconfigurations. Allowing generators to interconnect at penetrations levels close to—or at—a circuit's minimum load via the Fast Track on Supplemental Review gives utilities an opportunity to identify whether additional interconnection requirements are necessary without requiring the time and expense of a detailed study.

Both Hawaii and California will utilize minimum load measurements that are relevant for the time period that a generating facility will be online. This is important for solar PV technologies that are only online during daylight hours when minimum loads tend to be highest in most parts of the country. Thus, the minimum load can be measured between the hours of 10 a.m. and 2 p.m. for fixed solar systems. California's Rule 21 also includes a longer time period for generators using tracking systems.

In California, if minimum load data is not available, the utility will try to calculate minimum load, estimate it from existing data, or determine it from a power flow. If none of these options are available, the utility will default to using the 15% of peak load screen.[93]

The approaches agreed upon in California and Hawaii have potential to allow a greater number of generators to interconnect quickly while also providing the utility with sufficient opportunity to evaluate whether modifications need to be made to ensure safe and reliable operation at higher penetrations. Although increasing penetrations of generators boost the likelihood of unintentional islanding, high steady-state voltage, and the need to ensure protection coordination, it may be possible to properly evaluate those risks and identify modifications through a brief additional review without subjecting a proposed interconnection to a detailed study process. The merits of a refined Supplemental Review are discussed in more detail below.

Possible Modification: SGIP Screen 5 – Short Circuit Duty

SGIP Screen 5 determines whether the addition of the proposed Small Generating Facility will cause the short circuit current contribution ratio on the distribution system to exceed acceptable limits. This screen provides an important system check, but is one that is unlikely to be triggered by very small generators, including synchronous and induction generators.

For a number of years in California, generators below 11 Kilovolt-Amps (kVA) have been exempt from the short circuit duty screen.[94] In addition, to increase the efficiency of the review process, Hawaii recently adopted modifications to its Fast Track equivalent process to allow generators below certain sizes to skip screens where they are unlikely to cause issues of the sort addressed by the screen. In particular, Rule 14H contains an exemption that allows all generators below 10 kW to skip the short circuit contribution screen.[95] In addition, Hawaii allows generators up to 250 kW that are inverter-based to skip the short-circuit contribution screen.[96] Allowing very small generators to skip this screen is possible because their fault current level is insignificant compared to the feeder and thus they do not contribute significantly to short circuit current ratio issues.

At this time, it is appropriate to consider allowing very small systems of up to 25 kW to skip SGIP Screen 5. Allowing inverter-based systems up to or exceeding 250 kW to skip the screen may also be possible without significant system impacts but may require additional technical study before being adopted in SGIP. The approach of allowing generators up to 25 kW to skip the screen will enable distribution engineers to review applications more quickly, benefitting both the utility and the interconnection applicant, and will align well with an increase in the 10 kW Inverter Process to 25 kW, as recommended above.

Proposed Redline Modification of SGIP Section 2.2.1.5:

> The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability. Proposed Small Generating Facilities below 25 kW shall be exempt from this screen.

Possible Modification: SGIP Screen 6 – Line Configuration

The sixth SGIP Fast Track screen reviews the type of electrical service provided to a proposed generating facility and the line configuration at the point of interconnection and the transformer connection. This screen assesses the potential for overvoltage on the distribution system as a result of a loss of ground, or a phase, during a system fault.[97] The threat of overvoltage occurs on certain line configurations; the screen identifies those that are not a problem and allows those generators to proceed. However, generators connecting to a three-phase, four-wire primary distribution line with a three-phase transformer will fail the screen unless they are "effectively grounded."[98]

IEEE Standard 1547-2008 covering interconnection of distributed generation resources notes the need to ensure that the generating facility under review "shall not cause overvoltages that exceed the rating of the equipment connected to the Area EPS [Electric Power System] and shall not disrupt the coordination of the ground fault protection on the Area EPS."[99] However, the Standard does not recommend appropriate grounding methods to prevent overvoltages. As a result, the line configuration screen may push generators into a detailed study despite the fact that an appropriate grounding method can often be determined without a detailed study.

California's Rule 21 and Hawaii's Rule 14H include additional options that allow generators connecting to a three-phase, four-wire service to pass the line configuration screen if the aggregate nameplate rating of the generating facility is less than or equal to 10% of the line section's peak load.[100] In addition, in Rule 21, the line configuration screen "does not apply to Generating Facilities with a Gross Rating of 11 kVA or less."[101] In Hawaii, generators below 10 kW also bypass this screen.[102]

Currently, generators that fail the line configuration screen may be required to undergo a full study. However, once sufficient information is known about the proposed generator type and the point of interconnection, there is a relatively fixed number of known grounding solutions that are available to resolve overvoltage concerns.[103] Thus, rather than subjecting generators that fail the line configuration screen to a full study, specific equipment configurations that address overvoltage concerns may be addressed through a quicker review.

In recent revisions to Rule 14H, Hawaii added an option that allows generators that fail the line configuration screen to resolve overvoltage concerns through Supplemental Review. The utility and applicant may select from a list of pre-identified solutions based upon the technology and interconnection location.[104] Likewise, California's Rule 21 contains a general option embedded in the initial review screens that would allow generators that fail the line configuration screen to undergo "a quick review" of the failed screen to determine the requirements to address any failure.[105] This is similar to an option in SGIP that allows a utility to interconnect a generator through Fast Track despite the failure of a screen if it determines that the generator "may nevertheless be interconnected consistent with safety, reliability, and power quality standards…"[106]

Since identification of a technical solution for resolving the risk of overvoltage identified in the line configuration screen does not require full study, a revision to SGIP to clarify that resolution of this issue is appropriate through the Initial Review and/or Supplemental Review process may improve the efficiency and clarity of the procedures.

Based upon the experiences in California and Hawaii, the following SGIP revisions warrant consideration. Screen 6 could be modified in two ways: All generators below 11 kVA could be allowed to skip the screen, and generators below 10% of the line section's peak load could be allowed to pass the screen regardless of line configuration. For example:

2.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. 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 Transmission Provider's electric power 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.

Primary Distribution Line Type Configuration	Type of Interconnection to be Made to Primary Distribution Line	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

These modifications will allow utilities to continue to maintain safety, reliability, and power quality by identifying generators that pose overvoltage concerns and mitigating them through a technical solution. However, these modifications will also improve the efficiency and cost-effectiveness of the interconnection process by avoiding a full study when one is not needed. Although utilities currently have discretion under SGIP to resolve the overvoltage issues though section 2.2.3 or Supplemental Review, an explicit articulation of this option will improve transparency and certainty for applicants.

Possible Modification: SGIP Screen 9 – Transient Stability

SGIP Screen 9 examines whether a proposed generating facility will contribute to transient stability issues in the vicinity of the proposed point of interconnection. This screen evaluates whether the addition of the proposed generating facility will impact the ability of the electric power system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.[107] It requires that any generating facility that would cause the aggregate generation on the circuit to exceed 10 MW in an area with known or posted transient stability limitations to undergo further study.

Recent conversations on this topic in California, in PJM's service territory, and nationally have highlighted that the question posed by this screen may not actually be identifying the precise issue of central concern for small distribution level interconnections. A survey done in 2008 of electrical engineers and other experts in this area found that there was a general consensus that this screen should be modified to improve its ability to identify generators that need full study before they can be safely interconnected.[108] The current screen inquires whether a generating facility may contribute to known or posted transient stability issues, however there are no transient stability issues posted by most of the ISOs and thus it is often hard for utility distribution engineers to apply this screen.

In addition to the ambiguity in the current screen, it also does not address an issue of particular concern for small, distribution-interconnected generators being reviewed through Fast Track: whether the proposed generating facility has interdependencies with other queued generators on the transmission or sub-transmission system and thereby needs further study. As DG reaches higher penetrations, there is an increased likelihood aggregate generating capacity on the distribution system will have upstream impacts on the transmission system.

Recent variations to this screen have emerged in California and New Jersey to address this issue. In Rule 21, California recently adopted a modification to the transient stability test to more accurately address the transmission dependency issue.[109] The revised Rule 21 screen now asks whether the generator is interconnecting in an area with known transient stability limitations and whether it has interdependencies with any earlier queued transmission system interconnection requests. A generator will require detailed study if either circumstance exists.

In the Eastern United States, PJM recently sought approval for modifications to its FERC-regulated tariff to adopt a separate queue and expedited review process for non-transmission dependent generators.[110] The intent behind this change was to reduce the number of generators that need to be re-studied because an earlier queued generator with which they may interact dropped out of the queue.[111] PJM thus adopted a screening process to identify generators that would not impact the transmission system. The process evaluates the potential impacts of a proposed generator on the transmission system using a linear (DC) power flow program to analyze each transmission facility and to determine whether any contingencies can overload it. The results are then unitized in a manner that enables PJM to determine the MW impact a generator would have on a particular flowgate.[112] This process is different than a straightforward Fast Track screen because it is also used to determine cost allocation and deliverability. Nevertheless, it provides an example of another approach to evaluating transmission dependency as part of the interconnection process.

Taking into account the approaches in California and PJM's territory, it may be appropriate for SGIP Screen 9 to be modified in a manner that also examines whether a generator has dependencies with other generators yet to be studied on the transmission system. Since California's approach fits more neatly within the Fast Track screening process, it is proposed here.

Proposed Redline Modification of SGIP Section 2.2.1.9:

> The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall 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 busses from the point of interconnection), or the proposed Small Generating Facility shall not have interdependencies, known to the Transmission Provider, with earlier queued Transmission System interconnection requests.

Possible Modification: SGIP Screen 10 – No Construction

Currently, generators that are eligible for and pass through the first nine screens of the SGIP Fast Track process may be unable to interconnect without Supplemental Review or a full study if they require construction of any facilities by the utility on its system, as they will fail SGIP Screen 10.[113] This includes generators that need low-cost upgrades such as a service entrance or other interconnection facilities, as well as higher-cost modifications that require construction deeper into the distribution provider's system.

Generators that fail Screen 10 may be able to proceed through Supplemental Review, but only if construction is limited to "minor modifications to the Transmission Provider's electric system."[114] Generators that require more significant construction must go through the full study process. State procedures that mimic SGIP generally include a similar no construction screen.[115] Procedures modeled after California Rule 21 do not contain a similar restriction.[116]

When SGIP was developed, the type of facility most likely to utilize Fast Track was an onsite generator designed to primarily serve onsite load, with only excess generation sent to the local distribution system through an existing service entrance. These generators are less likely to require construction by the utility on its system. However, as the number of distributed generation facilities selling wholesale power has expanded, the no-construction screen has become one of the more commonly failed screens.[117]

Screen 10 serves at least two purposes in the interconnection process. First, a study may be needed to determine the extent of the construction needed by a utility on its own system. Second, a study may be needed to provide an estimate of the cost of upgrades for which the applicant will be responsible. In both cases, however, if upgrades are limited to those that only serve the interconnecting generator, a full study process may not be necessary. Therefore, modifications to this screen may be appropriate to help increase the efficiency of the Fast Track process.

When PG&E and SCE modified their federal small generator interconnection procedures in 2011, FERC approved modifications to their Fast Track and Supplemental Review processes to allow generators that require limited upgrades to proceed with a Fast Track interconnection without a full study. SCE modified its tenth screen to allow generators to pass Fast Track review so long as the upgrades needed are limited to those “solely attributable to the Generating Facility.”[118] Applicants wishing to interconnect without a full study must agree to pay the full cost of those upgrades without the benefit of an estimate. PG&E retained the original SGIP language in Screen 10, however it added to the “customer options meeting” a step that allows generators to proceed to Supplemental Review if interconnection facilities are required.[119] In Supplemental Review, the customer is given the option of agreeing to pay the costs upfront or of selecting to have a facilities study completed.[120] Generators that require distribution or network upgrades are required to proceed to a full study.[121]

In considering ways to increase the efficiency of the interconnection process while also ensuring continued safety and reliability, it is important to keep in mind the purpose of interconnection study processes. As discussed more in a later section, interconnection studies identify potential safety and reliability issues with a proposed generating facility and what upgrades, if any, may be required to address those issues. A study process also identifies the likely cost of required upgrades and how the associated costs will be allocated. However, as the updates in California illustrate, not all construction requires a detailed study to identify and mitigate potential safety and reliability issues. In addition, interconnection customers may be willing to accept responsibility for costs of certain upgrades with less specificity in exchange for a more efficient interconnection process.

Thus, with an increase in the number of small wholesale generators seeking interconnection to distribution systems, it may be possible to replace the tenth screen with a more suitable process that provides a utility increased time to estimate costs for necessary construction as the potential construction becomes more complex. For example, for generating facilities needing only interconnection facilities or minor modifications to the distribution provider's electric system, the utility could be given 15 days to develop a cost estimate and provide an interconnection agreement. For generators requiring more than minor upgrades, the distribution provider could be given 30 days to develop the cost estimate and provide an interconnection agreement. Alternately, the utility could opt to conduct a Facilities Study, if necessary, but no feasibility or system impact study would be required. Similar changes and timeframes could be incorporated into the Supplemental Review process. In all cases, the applicant would have to agree to pay the costs associated with the upgrades after reviewing the good-faith estimate provided by the utility.

In addition, a process could be created to allow a customer to opt into a Facilities Study (either after initial review or Supplemental Review) to determine the likely cost of upgrades prior to committing to them, or proceed directly to an interconnection agreement if agreement is received to pay the full costs of any upgrades.

Possible Modification: Supplemental Review

When a generator fails any one of the ten SGIP Fast Track screens, SGIP provides the applicant an opportunity to request a Supplemental Review if the utility concludes that such review might determine that the generator could interconnect without a full study.[122] The procedures do not define what the scope of the review will be or what issues may be resolved through the process.

As the number of applicants failing the initial review screens grows, Supplemental Review offers an opportunity to serve the twin goals of interconnection by providing additional time to resolve some of the safety and reliability concerns identified by the initial review screens while still allowing for efficient and cost-effective interconnection overall. In most cases, if the proposed generation facility is below 100% 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.

Recent modifications to the state procedures in Hawaii and California demonstrate how Supplemental Review may be used to evaluate generators connecting at higher penetrations. First, both states define the scope of the review process and what issues will be examined. In Hawaii, the "intent of the Supplemental Review is to provide a slightly more detailed review of only the conditions that cause the Generating Facility to fail the Initial Technical Review."[123] In California, the intent is to provide the utility with time to address certain specified conditions that may be adequately addressed with only limited additional review rather than requiring a full study. Defining the intent of the process and putting in place specific technical screens and timelines gives developers more certainty on what they can expect out of the process.

Both Hawaii and California retained the 15% of peak load screen in initial review, but the Supplemental Review procedures were then drafted to allow generators below a higher minimum load threshold to connect without a full study if any concerns identified at the higher penetration can be resolved. In Hawaii, for generators that fail the 15% of peak load screen, a full study shall not be required if the aggregate generating capacity is below 50% of minimum load on a line section for most generators[124] and 75% of minimum load for single-phase PV generators up to 10 kW on single-phase transformers that participate in net metering.[125] For generators that fail the line configuration screen, the tariff states that a full study will not be required where "a feasible solution from a pre-identified list of solutions maintained by the Company has been identified and agreed upon between the Company and the Customer."[126] The utilities may also address other issues identified in the initial review screens including short-circuit contribution, interconnection to networked systems (spot networks or area networks), the need for a dedicated transformer, and protective device requirements.[127]

In California, the Supplemental Review process has three technical screens that are applied similar to those in the initial review. The first screen determines whether the generator will cause the aggregate generation capacity on the line section to exceed 100%

of the minimum load, measured when the proposed generator is expected to be operating.[128] If a generator passes that screen, it will be subject to two additional screens.[129] The second screen applies power quality and voltage tests to identify operating requirements for the interconnecting generator or to determine whether a full study is required to identify those requirements. The third screen looks generally at whether the location of the proposed facility or the aggregate generation capacity on the line section could adversely impact safety or reliability, and if so, whether those can be addressed without requiring a full study.[130]

Under the SGIP rules for Supplemental Review, utilities have discretion to allow generators to interconnect that fail one or more of the initial review screens. Improving the clarity of the Supplemental Review process will likely provide additional certainty to applicants about the technical issues that will be considered in evaluating an interconnection and may guide them in site selection and planning. A revision to the Supplemental Review process may also enable a greater number of generators to proceed without further study, even without relaxation of the initial technical screens.

For a more defined and transparent Supplemental Review, the following modifications could be considered:

- Incorporate a requirement that generators below 100% of minimum load on a distribution feeder line section, measured during the hours the proposed facility will be online, be allowed to proceed through Supplemental Review.
- Include specific screens for Supplemental Review that provide additional guidance on the power quality, voltage regulation, safety, and reliability considerations that will be reviewed.

The Rule 21 Supplemental Review screens are attached to this report as Attachment 1.

LEVEL 3 (STUDY PROCESS) – POSSIBLE MODIFICATIONS

For generators that do not pass Fast Track, or are ineligible for Fast Track, SGIP requires generators to participate in a Study Process that consists of an initial scoping meeting and potentially three sequential studies: 1) a Feasibility Study; 2) a System Impact Study; and 3) a Facilities Study.

The Study Process determines potential impacts a proposed generator may have at or near the point of interconnection and what facilities or upgrades are necessary to maintain the safety, reliability and power quality of the electric power system. Perhaps the most important consideration for both the applicant and the utility is the level of study needed to determine interconnection requirements for a particular interconnection request. Put another way, what specifically should be addressed in an interconnection Study Process?

The answer may depend on the system configuration at the point of interconnection. For example, an interconnection to a spot or area distribution network may require a utility to look at impacts of reverse power flow to network protectors located at or near the point of interconnection. Likewise, impacts to service quality and the maintenance of voltage within normal operating ranges may depend on a proposed generator's distance from a substation, the type and location of voltage regulation devices, and the presence or absence of other generators (and types of generators) interconnected or proposed to interconnect to the same distribution feeder.

Failure of Fast Track technical review screens may help determine the appropriate focus of the Study Process. However, for interconnection applications that are not eligible for Fast Track, and therefore have not been subject to the application of Fast Track technical review screens, such screens would not provide any guidance in helping to determine the appropriate scope of an interconnection study. The Fast Track technical review screens also do not attempt to screen for every possible impact to electric power system reliability that may need to be assessed in the Study Process. For example, the present Fast Track screens do not look at the impact of reverse power flow on voltage regulation devices.

The three SGIP studies allow utility distribution engineers to take a fairly broad look at potential impacts to system reliability. Each has a different purpose. The Feasibility Study is a preliminary technical assessment of the proposed interconnection that looks for any potential adverse system impacts.[131] The System Impact Study is a detailed assessment of the effect the interconnection would have on the transmission provider's electric system and any other affected systems.[132] Depending on the generating facility, the System Impact Study may be required for both the transmission system and, separately, the distribution system.[133] The Facilities Study determines what modifications to the transmission provider's electric system are needed, including the detailed costs and scheduled completion dates for these required modifications.[134] This differentiated study process provides a developer with opportunities to exit the process as interconnection costs become clearer.

Prior to beginning the studies, the transmission provider and customer may attend a scoping meeting at which they may decide to skip the Feasibility Study and proceed directly to either a System Impact Study or a Facilities Study.[135] The parties may also agree to skip the Facilities Study and proceed directly to an interconnection agreement following the results of the Feasibility Study or System Impact Study.[136] Agreement on the scope and cost of a study is reflected in an interconnection study agreement entered between the applicant and the utility.

The length of time allowed for completion of the SGIP studies varies. The following table lists the time SGIP allows for each study, along with an estimate of the total time required after accounting for the time necessary to enter various study agreements.

Table 3. SGIP Study Timeframes

Stage of Study Process	Study Time	Total Time
Feasibility Study	30 business days	45-50 business days
System Impact Study	30-65 business days	45-70 business days
Facilities Study	30-45 business days	35-50 business days

As the ability to skip one or more of the three studies suggests, it is not clear that a three-study process is necessary for small generators, particularly for small residential and commercial installations. The ability to skip one or more of these studies may be enhanced if modifications to the Fast Track screening process can help to identify potential issues that may need a closer look during the Study Process.

A number of examples exist of recent changes made to shorten the study process from three to either one or two studies. In 2010, the CAISO adopted modifications to its interconnection tariff that made a number of changes to the study process. The CAISO moved most projects that used to proceed through the three serial studies into one annual "cluster study" that is composed of two different study phases. Phase I provides a preliminary look at the possible upgrades needed and options at the point of interconnection that could reduce overall upgrade costs, and provides a maximum cost responsibility for transmission system network upgrades along with a good-faith cost estimate of the interconnection facilities.[137] After this study is completed, there is an opportunity for applicants to decide whether they want to proceed with interconnection, and if they do, to put down a financial security deposit. The Phase II study is a more detailed look that updates the results of Phase I to account for withdrawal of some interconnection requests, and provides a final assessment of upgrades and cost allocation.[138]

In addition to the adoption of the cluster process, the CAISO also retained a serial study process for certain qualified applicants that were not electrically related to other queued generators and thus did not need to be studied in the cluster.[139] The CAISO's Independent Study Process (ISP) is similar to the SGIP Study Process, but it eliminates the Feasibility Study and consolidates the study process into a System Impact Study and a Facilities Study (which can be waived if no interconnection facilities or upgrades are identified). SCE and PG&E mirrored these changes for the most part in the modifications to their FERC-approved interconnection tariffs, which were approved in 2011.

The CAISO and SCE tariffs provide 90 calendar days for the completion of a System Impact Study.[140] CAISO and SCE provide 90 calendar days for the completion of a Facilities Study where upgrades are required, and 60 calendar days where only interconnection facilities are identified.[141]

The original California Rule 21, and numerous state procedures modeled on it, only provides for a single "Interconnection Study" rather than a three-part study process. Under the approved revisions to Rule 21, projects that do not qualify for interconnection under Fast Track will either be studied under an ISP process similar to the CAISO's process described above, or will be studied as part of the cluster study being conducted under the IOU's WDATs.[142]

The one-study process in place in many states and the two-study process recently adopted in California suggest that a full three-study process may not be necessary, particularly for small generators. In particular, the role of the Feasibility Study is fairly limited since much of the crucial detail of interest to generators, particularly regarding cost, does not come until the later studies.

The changes adopted in California do not necessarily shorten the overall study process, since the duration of each study is greater than that provided for in SGIP.[143] However, it is worth considering whether the times required for the System Impact Study and Facility Study can be kept the same in SGIP, or only modestly increased, even if the Feasibility Study is eliminated.

Possible Modification: Moving from Serial Study to Group/Cluster Study

As discussed above, the SGIP uses a serial study process for determining interconnection requirements for a particular generator.[144] Under a serial study approach, interconnection requests are studied one at a time, on a first-come, first-served basis. The order of requests received is made publicly available through posted interconnection queues.[145] Under this approach, an interconnection request may not be studied until all queued-ahead generators have been studied. The reason is two-fold. First, the amount of utility resources that can be devoted to the processing of interconnection requests may be limited. If utility resources are limited, it may be necessary to complete the study of generators further ahead in line to free up resources to study later-queued interconnection requests.

A second factor is the necessity to complete the interconnection of queued-ahead generators to determine the anticipated system configuration for the study of later-queued generators. This is an important consideration, because upgrades that may be required to interconnect a generator that is ahead in the queue may facilitate the interconnection of generators further behind in the queue. On the other hand, if a generator earlier in the queue decides not to move forward with its interconnection, and therefore upgrades that would have been completed to accommodate that generator are not completed, the study of later-queued generators would not assume the existence of those upgrades. The result is that a generator further back in the queue may be responsible for the completion of the upgrades that would have otherwise been completed to facilitate the interconnection of the queued-ahead generator, if it had gone forward.

There may also be a need to re-study the later interconnection requests. A high number of speculative projects in an interconnection queue that drop out during or after the study process can result in a ripple effect that can impact and necessitate restudy of applicants further back in the interconnection queue. This lengthens the serial study process and increases costs. In sum, the requirements for a generator further back in the queue may not be able to be determined until the status of all generators that are ahead in line have been determined.

The serial study process may work well in situations where a utility is a) processing a low volume of interconnection applications such that existing resources are sufficient to timely handle the volume of interconnection requests being received, and b) generators seeking interconnection are sufficiently independent such that the ability to move forward with studies is not significantly delayed by the need to process earlier interconnection requests to determine the base case for generators farther back in the queue. The serial study process becomes less efficient when the volume of interconnection requests and interrelatedness of interconnection requests reaches a point where significant delays in processing interconnection requests results. Under these conditions, the serial study process can lead to long delays, and other options may need to be explored.[146]

When a utility begins to receive sufficiently high volumes of interconnection requests, and high penetrations are reached such that multiple interconnection requests may impose impacts on the same area of an electric power system, a group or cluster study process may be more efficient. ISOs and individual utilities in the United States have identified some of the possible benefits of studying interconnection requests in groups or clusters and have adopted changes to implement these procedures. FERC recently approved modifications to the Open Access Transmission Tariffs for CAISO, MISO and PJM that reflect a move toward group studies.[147] Two of the California IOU's followed CAISO's lead and adopted a cluster study process for interconnection requests interrelated with the transmission system.[148] Finally, the CPUC is considering adopting a group study process for distribution-level interconnections under Rule 21.[149]

There are a number of advantages to a group study approach. First, a group study process may make more efficient use of limited utility resources by enabling multiple studies to be combined. Second, a group study process may allow interconnection applications to be processed more quickly. Studying a group of projects at once eliminates the need for later queued projects to wait in line. Finally, a group study process may allow for a beneficial sharing of costs across generators, both for study and for upgrades that may be necessary to accommodate the interconnection of multiple generators. Imposing the full cost of upgrades—which may facilitate the interconnection of multiple generators—on the first generator that triggers the upgrades may pose a barrier to market growth. By studying generators together, the costs of upgrades can be spread equitably across the generators that may ultimately benefit.

There may also be negatives to the group study approach. First, the transmission cluster study process in California takes nearly two years to complete. Thus, while it may place a lower burden on utility resources, it also may require more time overall.[150] However, in California the serial study queues were so clogged that there was an expectation that it could take many years to complete the process.[151] Second, where a location has a high number of speculative projects in its interconnection queue, utilities may need to develop a method of sorting out how many total combined MW to realistically study and how to estimate and assign the cost of upgrades. Assuming that only a percentage of interconnection requests will actually move forward, studying the full number of proposals could result in inflated estimates of the amount of upgrades actually required.

An important consideration in a group study process is which interconnection requests to study together. The answer should generally depend on which interconnection requests pose interrelatedness considerations. Projects that are transmission dependent likely need to be studied with other transmission-dependent projects. However, projects that do not interact with the transmission system could be studied in smaller groups with only the other projects they interact with on the distribution system.

The group study approaches being implemented across the United States appear to offer significant promise for dealing with high volume and high penetration situations at the distribution level. Each region has taken a slightly different approach to the issue at this stage and further information is needed on what the pros and cons are of each approach. This is a possible area for improvement of SGIP that warrants further consideration.

4. RECOMMENDATIONS

This section recaps and summarizes the recommendations provided in Section 3:

- Update federal and state interconnection procedures to meet the demands of a growing national marketplace for solar PV and other small renewable generators interconnecting to electric power distribution systems.
- Incorporate a pre-application report through which an interconnection applicant can request information about specific, relevant technical conditions at a proposed point of interconnection.
- Extend the 10 kW Inverter Process to generators up to 25 kW.
- Shorten the time for determining a 10 kW Inverter Process application is complete to 3 business days after receipt.
- Consider automatic approval of 10 kW Inverter Process applications after an identified timeframe unless an applicant is notified otherwise by a utility.
- Allow for online submission of interconnection applications.
- Allow for electronic signatures to be provided on interconnection applications.
- Consider modifying Fast Track eligibility to take into account system conditions at the point of interconnection. A proposed approach is provided in Table 2.
- Allow generators up to 25 kW to skip the short circuit duty screen (SGIP Screen 5).
- Modify the line configuration screen (SGIP Screen 6) in two ways: allow generators less than 11 kVA to skip the screen; and allow generators below 10% of the line section's peak load to pass the screen regardless of line configuration.
- Modify the transient stability screen (SGIP Screen 9) in a manner that examines whether a generator has dependencies with other generators yet to be studied on the transmission system.
- Replace the no construction screen (SGIP Screen 10) with a process that provides a utility increased time to estimate costs for necessary construction as potential construction becomes more complex.
- Allow a customer to opt into a Facilities Study (either after Initial Review or Supplemental Review) to determine the likely cost of upgrades prior to

committing to them, or allow a customer to proceed directly to an interconnection agreement if agreement is received to pay the full costs of any upgrades.

- Provide a more defined and transparent Supplemental Review process, including consideration of the following: incorporate a requirement that generators below 100% of minimum load on a distribution feeder line section, measured during the hours the proposed facility will be online, be allowed to proceed through Supplemental Review; and include specific screens for Supplemental Review that provide additional guidance on the power quality, voltage regulation, safety and reliability considerations that will be reviewed.
- Consider replacing a three-study process with a two-part study process, and consider whether the times required for the System Impact Study and Facility Study to be completed can be kept the same, or only modestly increased, even if the Feasibility Study is eliminated.
- When a utility begins to receive sufficiently high volumes of interconnection requests and high penetrations are reached such that multiple interconnection requests may impose impacts on the same area of an electric power system, a group or cluster study process may be more efficient than a serial study process.

5. CONCLUSIONS

The U.S. solar industry is fast approaching the limits of the practicality of existing interconnection processes. Interconnection reform is necessary and unavoidable if we hope to achieve the renewable energy goals of states, federal departments, and the private sector. This report serves as an extension of the NREL *Interconnection Screens Report*, and, as such, provides an important procedural bridge to that next iteration of interconnection reforms needed in the United States.

The report focuses on the federal SGIP, specifically recommending changes to the pre-application process and the 10 kW, Fast Track, and Study Processes; however, these recommendations could generally be applied to many state interconnection procedures as well. Many of these recommendations result from the work of stakeholder collaborations in states like Hawaii and California, which are currently experiencing high-penetration areas and high volumes of interconnection applications.

When we consider the experience of these states, we begin to get a glimpse of the emerging scenarios in the rest of the country. As the cost of solar PV systems decline and demand increases, it will be increasingly important to streamline interconnection processes in other states. This interconnection reform process will not only result in a more responsive, agile solar industry but also a safer and cleaner electric power system.

6. ATTACHMENT 1: California Rule 21 Supplemental Review Screens (Rule 21 G.2)

G. Engineering Review Details

2. Supplemental Review Screens

The Supplemental Review consists of Screens N through P. If any of the Screens are not passed, a quick review of the failed Screen(s) will determine the requirements to address the failure(s) or that Detailed Studies are required. In certain instances, Distribution Provider may be able to identify the necessary solution and determine that Detailed Studies are unnecessary. Some examples of solutions that may be available to mitigate the impact of a failed Screen are:

1. Replacing a fixed capacitor bank with a switched capacitor bank

2. Adjustment of line regulation settings

3. Simple reconfiguration of the distribution circuit.

a. Screen N: Penetration Test

Where 12 months of line section minimum load data is available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate Generating Facility capacity on the Line Section less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the Generating Facility?

- If yes (pass), continue to Screen O

- If no (fail), a quick review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Screen O. (Note: If Electrical Independence tests and Detailed Studies are required, Applicants will continue to the Electrical Independence Tests and Detailed Studies after review of the remaining Supplemental Review Screens).

Note 1: If none of the above options are available [for determining minimum load], this screen defaults to [the 15% peak load screen].

Note 2: The type of generation will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen. Solar generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for systems utilizing tracking systems), while all other generation uses absolute minimum load.

Note 3: When this screen is being applied to a [net energy metered] Generating Facility, the net export in kW, if known, that may flow across the Point of Common Coupling into Distribution Provider's Distribution System will be considered as part of the aggregate generation.

Note 4: Distribution Provider will not consider as part of the aggregate generation for purposes of this screen Generating Facility capacity known to be already reflected in the minimum load data.

Note 5: NEM Generating Facilities with net export less than or equal to 500 kW that may flow across the Point of Common Coupling into Distribution Provider's Distribution or Transmission System will not be studied in the Transmission Cluster Study Process, but may be studied under the Independent Study Process.

Significance: Penetration of Generating Facility installations that does not result in power flow from the circuit back toward the substation will have a minimal impact on equipment loading, operation, and protection of the Distribution System.

b. Screen O: Power Quality and Voltage Tests

In aggregate with existing generation on the line section,

a) Can it be determined within the Supplemental Review that the voltage regulation on the line section can be maintained in compliance with Commission Rule 2 and/or Conservation Voltage Regulation voltage requirements under all system conditions?

b) Can it be determined within the Supplemental Review that the voltage fluctuation is within acceptable limits as defined by IEEE 1453 or utility practice similar to IEEE 1453?

c) Can it be determined within the Supplemental Review that the harmonic levels meet IEEE 519 limits at the Point of Common Coupling (PCC)?

- If yes to all of the above (pass), continue to Screen P

- If no to any of the above (fail), a quick review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Screen P. (Note: If Electrical Independence tests and Detailed Studies are required, Applicants will continue to the Electrical Independence Tests and Detailed Studies after review of the remaining Supplemental Review Screens).

Significance: Adverse voltages and undesirable interference may be experienced by other Customers on Distribution Provider's Distribution System caused by operation of the Generating Facility(ies).

c. Screen P: Safety and Reliability Tests

Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create impacts to safety or reliability that cannot be adequately addressed without Detailed Study?

- If yes (fail), review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Section G.3

- If no (pass), Supplemental Review is complete.

Significance: In the safety and reliability test, there are several factors that may affect the nature and performance of an Interconnection. These include, but are not limited to:

- Generation energy source

- Modes of synchronization

- Unique system topology

- Possible impacts to critical load customers

- Possible safety impacts.

The specific combination of these factors will determine if any system study requirements are needed. The following are some examples of the items that may be considered under this screen:

1. Does the Line Section have significant minimum loading levels dominated by a small number of customers (i.e. several large commercial customers)?

2. Is there an even or uneven distribution of loading along the feeder?

3. Is the proposed Generating Facility located in close proximity to the substation (i.e. <2.5 electrical line miles), and is the distribution line from the substation to the customer composed of large conductor/cable (i.e. 600A class cable)?

4. Does the Generating Facility incorporate 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?

5. Is operational flexibility 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?

6. Does the Generating Facility utilize certified anti-islanding functions and equipment?

Endnotes

1 Lori Bird, David Hurlbut, Pearl Donohoo, Karlynn Cory, and Claire Kreycik, *An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015*, National Renewable Energy Laboratory, Technical Report NREL/TP-6A2-45041, p.3 (March 2009), *available at* www.nrel.gov/docs/fy10osti/45041.pdf.

2 2011 National Summit on RPS, Presentation of Lawrence Berkeley National Laboratory, Oct. 26-27, slide 22: http://www.cleanenergystates.org/assets/Uploads/2011-RPS-Summit-Combined-Presentations-File.pdf.

3 Larry Sherwood, *U.S. Solar Market Trends 2011* (Interstate Renewable Energy Council), p. 5 (July 2012).) *available at* http://www.irecusa.org/news-events/publications-reports/.

4 *See Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, FERC Stats. & Regs. ¶ 31,180 (Order 2006), order on reh'g., Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005)(Order 2006-A), *order on reh'g*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006)(Order 2006-B), *available at* http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

5 *See* Solar Energy Industries Association Petition for Rulemaking to Update Small Generator Interconnection Rules and Procedures for Solar Electric Generation, FERC Docket No. RM12-10-000 (SEIA Petition) (February 16, 2012).

6 *See Massachusetts Distributed Generation Interconnection Report*, Prepared for Massachusetts Department of Energy Resources and Massachusetts Clean Energy Center by KEMA, pp. 25-26 (July 2011), *available at* www.mass.gov/eea/docs/doer/renewables/dg-inter.pdf.

7 *See, e.g., PJM Interconnection, L.L.C.*, FERC Docket No. ER12-1177-000, Transmittal Letter, p. 1 (February 29, 2012) ("[PJM] hereby submits modifications to its Open Access Transmission Tariff ("PJM Tariff") to implement interconnection queue process reforms that are intended to relieve bottlenecks in the interconnection queue and provide for greater certainty and transparency."); *Cal. Independent System Operator Corp.,* FERC Docket No. ER11-1830-000, Transmittal Letter, p. 2 (October 19, 2010) ("[S]ince 2008, the ISO has experienced a large and rapidly increasing volume of small generator interconnection requests, to a level which has made it impossible for the ISO to study these projects serially under the method within the timelines of the current [SGIP]"); *So. Cal. Edison Co.,* Docket No. ER11-2977-000, Transmittal Letter, p. 3 (March 1, 2011) ("The revisions proposed by SCE will create a set of comparable rules for processing Small and Large Generator Interconnection Requests ("IRs") and address the delays in processing the WDAT's SGIP queue."); *Pacific Gas & Electric Co.*, FERC Docket No. ER11-3004-000, Transmittal Letter, p. 4 (March 2, 2011) ("Like the CAISO, PG&E has similarly experienced a dramatic increase in the number of small generator interconnection requests to interconnect with PG&E's distribution system. These requests, which are processed through PG&E's WDT SGIP, have also arisen as a result of California's RPS requirements. Currently, PG&E has a backlog of over 170 interconnection requests for small generators."); *see also Hawaiian Elec. Co.*, Hawaii Public Utilities Commission Docket No. 2010-0015 (2011) (addressing reforms to Rule 14H); Order Instituting Rulemaking, California Public Utilities Commission (CPUC) Docket No. R.11-09-011 (2012) (addressing reforms to California's Rule 21 to accommodate increasingly large numbers of interconnection requests to the distribution grid from exporting and wholesale generators).

8 Michael Coddington, Benjamin Kroposki, Barry Mather (National Renewable Energy Laboratory); Kevin Lynn, Alvin Razon (Department of Energy); Abrahim Ellis, Roger Hill (Sandia National Laboratories); Tom Key, Kristen Nicole, Jeff Smith (Electric Power Research Institute), *Updating Interconnection Screens for PV System Integration,* National Renewable Energy Laboratory Technical Report NREL/TP-5500-54063 (Interconnection Screens Report) (January 2012), *available at* www.nrel.gov/docs/fy12osti/54063.pdf.

9 FERC SGIP § 2.2.1.2 ("For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is

that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.").

10 *See* SEIA Petition, p.1.

11 *See* Kevin Fox and Jason Keyes, *Comparison of the Four Leading Small Generator Interconnection Procedures* (Solar America Board for Codes and Standards), p. 1 (2008), *available at* http://www.solarabcs.org/about/publications/reports/interconnection/index.html.

12 *See Id.*

13 *See* CPUC Decision 00-12-037 (December 21, 2000), *available at* http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION//4117.pdf.

14 http://standards.ieee.org/findstds/standard/1547-2003.html.

15 IEEE Std 1547™ -2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems ("It is beyond the scope of this standard to address the methods used for performing EPS impact studies, mitigating limitations of the Area EPS, or for addressing the business of tariff issues associated with interconnection.").

16 FERC Order 2006, *available at* http://www.ferc.gov/EventCalendar/Files/20050512110357-order2006.pdf.

17 *Id.*

18 FERC Order 2006, FERC Order 2006-A, and FERC Order 2006-B, *supra*, note 4.

19 *See* FERC Order 2006 at P 512.

20 R. Brent Alderfer, Thomas Starrs, and M. Monika Eldridge, *Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects*, NREL/SR-200-28053 (Revised July 2000), *available at* www.nrel.gov/docs/fy00osti/28053.pdf.

21 The mention of 'best practices' was an indirect reference to the National Association of Regulatory Commissioners (NARUC) Small Generation Resource Interconnection Procedures.

22 *See Connecting to the Grid* (Interstate Renewable Energy Council), vol. 12, no. 1*, available at* http://www.irecusa.org/wp-content/uploads/January_2009_-_Connecting_to_the_Grid.pdf.

23 For example, Hawaii (Rule 14H), Nevada (Rule 15), and New Mexico incorporate significant portions of Rule 21 into state commission-approved interconnection tariffs.

24 *Database of State Incentives for Renewables and Efficiency* (DSIRE), Summary Maps, Interconnection, *available at* http://www.dsireusa.org/documents/summarymaps/interconnection.pdf.

25 *See* 2011 National Summit on RPS, Presentation of Lawrence Berkeley National Laboratory, Oct. 26-27, slide 8: http://www.cleanenergystates.org/assets/Uploads/2011-RPS-Summit-Combined-Presentations-File.pdf.

26 *See* DSIRE, Summary Maps, RPS Policies, *available at* http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

27 *See* 2011 National Summit on RPS, Presentation of Lawrence Berkeley National Laboratory, Oct. 26-27, slide 7: http://www.cleanenergystates.org/assets/Uploads/2011-RPS-Summit-Combined-Presentations-File.pdf.

28 *See* Lawrence Berkeley National Laboratory, RPS Compliance Data Spreadsheet, *available at* http://www.dsireusa.org/rpsdata/index.cfm (June 2012).

29 *See, e.g., The Bottom Line On…: Answers to frequently asked questions about climate and energy policy* (World Resources Institute)*,* Issue 19, pp.1-2 (January 2011), *available at* http://pdf.wri.org/bottom_line_emerging_solar_metering_policies.pdf; *Connecting to the Grid* (Interstate Renewable Energy Council), Vol. 13, No. 8, p.2 (August 2010), *available at* http://www.irecusa.org/2010/08/august-2010-connecting-to-the-grid-newsletter/.

[30] Kevin Fox & Laurel Varnado, *Sustainable, Multi-Segment Market Design for Distributed Solar Photovoltaics* (Solar America Board for Codes and Standards), p. 31 (October 2010), *available at* http://www.solarabcs.org/about/publications/reports/market-design/pdfs/ABCS-17_studyreport.pdf.

[31] *See* CPUC, RPS Procurement website, *available at* http://www.cpuc.ca.gov/PUC/energy/Renewables/procurement.htm (last visited June 28, 2012).

[32] *See* SEIA Petition, p. 6.

[33] *See U.S. Solar Market Trends 2011*, p.5, *supra*, note 3.

[34] Becky Campbell & Mike Taylor, *2011 SEPA Utility Solar Rankings,* p. 6 ("Utility Solar Rankings") (May 2012), *available at* www.solarelectricpower.org/media/257582/final%202011%20utility%20solar%20rankings%20report.pdf.

[35] *See Cal. Independent System Operator Corp.*, 140 FERC ¶ 61,070, at P 4 (July 24, 2012) (noting the CAISO's claims that its queue has four times the amount of new generating capacity necessary to meet a 33% RPS goal and that it expects that 75% of these projects will not be completed). *See also Briefing on Generation Interconnection Trends*, presentation by Bob Emmert to the CAISO Board of Governors Meeting, General Session, July 13-14, 2011, slide 2 (Reporting that the CAISO had over 70 GW of renewable energy projects in its current queue, including over 35 GW of solar PV), *available at* www.caiso.com/2bba/2bba799624040.pdf*; Briefing on Renewable Integration in the ISO Generator Interconnection Queue*, presentation by Bob Emmert to the CAISO Board of Governors Meeting, General Session, October 27-28, 2011, slide 2 (*showing that a significant amount of queued capacity dropped out of the queue between July 2011 and October 2011, including approximately 7 GW of solar PV)*, *available at* http://www.caiso.com/Documents/BriefingRenewableIntegration_in_ISO_GeneratorInterconnectionQueue_Presentation.pdf.

[36] *See* United States Department of Energy SunShot Initiative, High Penetration Solar Portal, *available at* https://solarhighpen.energy.gov/projects/does_high_penetration_solar_deployment_projects (last accessed June 30, 2012).

[37] K. Burman, J.Keller, and B. Kroposki (National Renewable Energy Laboratory); P. Lilienthal, R. Slaughter, and J. Glassmire (Homer Energy, LLC), *Renewable Power Options for Electrical Generation on Kaua'i: Economics and Performance*, NREL/TP-7A40-52076, p. 34 (November 2011), *available at www1.eere.energy.gov/office_eere/pdfs/52076.pdf.*

[38] DSIRE, Summary Maps, RPS Policies, *supra*, note 26.

[39] Utility Solar Rankings, p. 7, *supra*, note 34.

[40] *Id.* at p. 22.

[41] *Id.* at p. 14.

[42] Scoping Memo and Ruling of Assigned Commissioner, CPUC Docket No. R.11-09-011, (Order Instituting Rulemaking to improve distribution level interconnection rules for certain classes of electric generators), (6/20/2012), *available at* http://docs.cpuc.ca.gov/EFILE/RULC/169188.htm.

[43] Interconnection Screens Report, p. 10.

[44] *See, e.g.,* Motion to Intervene and Comments of SunPower Corporation, FERC Docket No. RM-12-10-000, p. 3 (March 26, 2012) (alleging that certain utilities rejects are rejecting all projects, whether state or federal jurisdictional, once "the amount of proposed solar generation exceeds 15% of a circuit's rated peak capacity"), *available at* http://elibrary.ferc.gov/idmws/File_list.asp?document_id=14006815; Motion to Intervene and Comments of enXco Development Corporation, FERC Docket No. RM-12-10-000, pp.3-4 (March 27, 2012) (alleging that a distribution utility in Massachusetts has a practice of setting hard capacity

limits on individual circuits based on voltage class), *available at* http://elibrary.ferc.gov/idmws/File_list.asp?document_id=14006814.

45 A summary of each state's interconnection procedures is available at DSIRE: http://www.dsireusa.org.

46 For example, Connecticut, Illinois, Kentucky, North Carolina, Pennsylvania, South Dakota, and others adopted the SGIP technical screens for their respective Fast Track processes. Other states feature slight variations to certain of the SGIP screens, or do not include certain of the screens, including Virginia and Oregon and high penetration states such as Colorado, New Jersey and Massachusetts. Though initial review in Hawaii and California is structured differently, the technical review screens are highly consistent with the SGIP.

47 Rule 21, E.1. The California Public Utilities Comission approved revisions to Rule 21 through Decision No. 12-09-018, issued on September 20, 2012. The previously effective Rule 21 and the newly adopted, revised version of Rule 21 are included as Attachments to the decision: Attachment E and Attachment A, respectively. Decision No. 12-09-018 is *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M028/K168/28168335.pdf.

48 *Id.*

49 SGIP Attachment 5 contains the terms and conditions of the 10 kW Inverter Process agreement, and establishes the procedure for utility processing. Since the interconnection agreement is embedded within the application documents, the customer does not need to complete a separate interconnection agreement.

50 FERC Order 2006 at P 405.

51 FERC Order 2006 at P 403; *see also* Interconnection Screens Report at p. 2.

52 N.M. Code R. § 17.9.568.10.

53 52 Pa. Code §§ 75.34(1), 75.37.

54 Fla. Admin. Code § 25-6.065(4)-(6).

55 O.A.R. 860-082-025(2)(a).

56 Massachusetts Model Interconnection Tariff: Standards for Interconnecting Distributed Generation § 3.0, D.P.U. Order No. 09-03-A, Appendix B, *available at* www.env.state.ma.us/dpu/docs/electric/09-03/82009noiapb.pdf.

57 *US Solar Market Trends 2011*, p. 7, *supra*, note 3.

58 Vermont Public Service Board, "Order implementing registration procedure for net-metered photovoltaic generation systems up to 10 kilowatts in capacity, pursuant to 30 V.S.A. § 219a(c)(1)" (May 31, 2012).

59 20 V.A.C. 5-315-30.

60 FERC Order 2006 at P 402.

61 SDG&E's online application for interconnection and net metering of systems 30 kW or less, *available at* https://nemapplication.sempra.com.

62 SCE's online NEM application, *available at* http://www.sce.com/customergeneration/solar-nem-application.htm.

63 Con Edison's Solar Energy Interconnection website, *available at* http://www.coned.com/dg/solarenergy/interconnection.asp.

64 *See* National Conference of State Legislatures' map of states that have adopted UETA, *available at* http://www.ncsl.org/issues-research/telecom/uniform-electronic-transactions-acts.aspx; *see also* Electronic Signatures in Global and National Commerce Act, Pub. L. No. 106-229, 114 Stat. 464 (2000) (codified at 15 U.S.C. § 7001 et seq.) (applies to the three states that have not adopted the UETA).

65 SCE's online NEM application for systems 10 kW or less, *supra*, note 62.

66 FERC Order 2006 at P 18.

67 FERC Order 2006 at P 171.

68 SGIP § 2.4.1.

69 Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) currently track the queues for WDAT applications and provide screen failure data. Queue data with screen failure detail is available for SCE at www.sce.com/nrc/aboutsce/regulatory/openaccess/wdat/wdat_queue.xls (Based on data updated on July 6, 2012)**;** and for PG&E at www.pge.com/includes/docs/word_xls/b2b/newgenerator/wholesalegeneratorinterconnection/PGE_WDT_Queue_29June2012.xls (Based on data updated on June 29, 2012).

70 SGIP § 2.1.

71 FERC Order 2006 at P 172.

72 CAISO GIP at § 5.1. CAISO explained: "From a transmission engineering perspective, a 5 MW generating facility is relatively small and generally would cause no greater impact than a 2 MW generator, such that including 5 MW facilities in the Fast Track Process will not jeopardize the safety and reliability of the ISO controlled grid." *Cal. Independent System Operator Corp.,* FERC Docket No. ER11-1830-000, Transmittal Letter to FERC, p. 21 (Oct. 19, 2010). FERC agreed, noting that SGIP was designed for distribution level interconnections and "may have been more restrictive than necessary when applied to the CAISO [transmission] grid." *Cal. Independent System Operator Corp.,* 133 FERC ¶ 61,223, at P 115 (December 16, 2010).

73 PG&E's tariff is known as their Wholesale Distribution Tariff (WDT), but for simplicity sake we will refer to both the utility tariffs as WDATs.

74 SCE WDAT GIP at Section 1.

75 PG&E WDT GIP at § 2.1 ("The Fast Track Process is available . . . if the Generating Facility is no larger than 5 MW (up to 3 MW for a 21kV interconnection, and up to 2MW on a 12kV interconnection) . . .").

76 *See So. Cal. Edison Co.*, 135 FERC ¶ 61,093, at PP 74-75.

77 *See, e.g.,* DSIRE, State Interconnection Pages: Connecticut, Indiana, Maine, Iowa, Oregon, Utah, Colorado, South Dakota, Illinois, North Carolina, Virginia, District of Columbia, Delaware, Pennsylvania, New Jersey, and New Mexico, *supra*, note 45.

78 *See, e.g.,* DSIRE, State Interconnection Pages: Nebraska, Georgia and Louisiana, *supra*, note 45.

79 *See, e.g.,* DSIRE, State Interconnection Pages: Massachusetts, Nevada, Hawaii, *supra*, note 45.

80 Rule 21 at E.2.b.i, *supra*, note 47. The SDG&E eligibility limit for fast track differs from those of SCE and SDG&E due to differences in the voltage level and conservation voltage requirements of SDG&E's distribution system.

81 *See So. Cal. Edison,* 135 FERC ¶ 61,093, at P 65 ("[SCE] agrees that the screens are the limiting factor in determining fast track eligibility, particularly at voltages of 16 kV and below. [SCE] states, however, that for voltage circuits greater than 16 kV, the screens would not necessarily be able to filter out projects larger than 2 MWs due to higher average peak loads on higher voltage circuits.").

82 *See, e.g.,* SGIP § 2.2.1.2; Rule 21 Screen M, *supra*, note 47; *but see, e.g.,* Massachusetts Standards for Interconnecting Distributed Generation, Appendix B, Figure 1 (applying as the penetration screen a threshold of 7.5% of circuit annual peak load.); New Jersey Interconnection Procedures, N.J.A.C. § 14:8-5.5(f) (Setting the aggregate generation capacity at "10 percent (or 15 percent for solar electric generation) of the total circuit annual peak load.").

83 *See* SCE and PG&E queue data, *supra*, note 69.

84 *See, e.g.,* Rule 21 (old) Screen 4 Significance Notes, *supra*, note 47 (Attachment E to Decision No. 12-09-018); California Energy Commission (CEC), *California Interconnection Guidebook: A Guide to Interconnecting Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California's Electric Rule 21*, p. 43 (CEC Guidebook) (September 2003), *available at* www.energy.ca.gov/reports/2003-11-13_500-03-083F.PDF.

85 Interconnection Screens Report, p. 2.

[86] CEC Guidebook, p. 43, *supra*, note 84; Interconnection Screens Report, p. 2 ("The capacity penetration threshold is expressed in terms of peak load, as opposed to the intended metric (minimum load) because peak load data is tracked and accessible to utilities.").

[87] CEC Guidebook, p. 43, *supra*, note 84; Interconnection Screens Report, p. 2 ("For typical distribution circuits in the United States, minimum load is approximately 30% of peak load.").

[88] Interconnection Screens Report, p. 7.

[89] Administrative Rules of Montana 38.5.8410(2)(a) (Montana Small Generator Interconnection Procedures).

[90] Arizona Interconnection Document, Section 4.2(a), *available at* http://images.edocket.azcc.gov/docketpdf/0000074361.pdf (attached as Exhibit to Decision No. 69674).

[91] Hawaii Rule 14H, Appendix III, 3(d).

[92] Rule 21 G.2, Screen M & N.

[93] *Id.* (Note 1).

[94] *See, e.g.,* Rule 21 (old) I.3.f (allowing projects 11 kVA or less to skip the short-circuit contribution and line configuration screens), *supra*, note 47 (Attachment E to Decision No. 12-09-018); Rule 21 § G.1.f, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[95] Rule 14H, Appendix III, Section 2, Screen 6.

[96] Rule 14H, Appendix III, Section 2.

[97] SGIP § 2.2.1.6.

[98] *Id.*

[99] IEEE Standard P.1547-2008 (4.1.2) Integration with Area EPS Grounding (working group draft).

[100] Rule 21 at G.2.h, *supra,* note 47 (Attachment A to Decision No. 12-09-018). For further explanation, see Mike Sheehan, *Photovoltaic Generation: Temporary Overvoltage Impact and Recommendations* (Solar America Board for Codes and Standards), p.16 ("The 10% limit ensures that the local load is much greater than the output of the generating facility so that the load causes a significant voltage drop and prevents the possibility of overvoltage caused by loss of system neutral grounding.") (Temporary Overvoltage Report) (*publication pending*).

[101] *Id.*

[102] Hawaii Rule 14H at 38D-8, 38D-12.

[103] For a more complete discussion of the grounding options see Temporary Overvoltage Report, *supra*, note 100.

[104] Hawaii Rule 14H at 38D-17.

[105] Rule 21 at G.1, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[106] SGIP § 2.2.3.

[107] North American Electric Reliability Corporation, Glossary of Terms Used in Reliability Standards, Apr. 20, 2009, available at: www.nerc.com/files/Glossary_2009April20.pdf.

[108] Michael Sheehan and Thomas Cleveland, *Updated Recommendations for Federal Energy Regulatory Commission Small Generator Interconnection Procedures Screens* (Solar America Board for Codes and Standards), p. 8 (July 2010).

[109] Rule 21 § G.1.l, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[110] PJM Interconnection L.L.C., Transmittal Letter and Clean Tariff, Docket No. ER12-1177-000 (Feb. 29, 2012).

[111] *Id.* at 12-13.

[112] Proposed PJM Tariff Sections 110.1.1, 111.1.1, and 112.1.1s.

[113] SGIP § 2.2.1.10.

[114] SGIP §§ 2.3.1 (providing changing meters, fuses, or relay settings as examples of minor modifications), 2.4.1.2, 2.4.1.3.

[115] *See, e.g.* DSIRE, State Interconnection Pages: Illinois, Colorado, and North Carolina; *but see* Indiana and South Dakota, *supra*, note 45.

[116] *See, e.g.* DSIRE, State Interconnection Pages: New Mexico, Massachusetts, and Nevada, *supra*, note 45.

[117] *See* SCE and PG&E queue data, *supra*, note 69.

[118] SCE WDAT § 6.5.10; *see also So. Cal. Edison Co.,* 135 FERC ¶ 61,093, at P 94.

[119] PG&E WDT § 2.3.3; *see also Pacific Gas & Electric Co.*, 135 FERC ¶ 61,094, at P 65.

[120] PG&E WDT § 2.4.1.1.

[121] PG&E WDT § 2.3.4.

[122] SGIP § 2.3.2.

[123] Hawaii Rule 14H, Sheet No. 34D-16.

[124] Hawaii Rule 14H, Appendix III, 3(d).

[125] "Hawaiian Electric companies ease pay to solar electric power", Hawaiian Electric Company News Release, September 18, 2012, *available at*: http://www.heco.com/vcmcontent/StaticFiles/pdf/20120918-easier2addsolar2roofs.pdf.

[126] Hawaii Rule 14H, Appendix III, 3(d).

[127] Hawaii Rule 14H, Sheet No. 34B-9 – 12.

[128] Rule 21 G.2, Screen N, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[129] Rule 21 G.2, Screen O, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[130] Rule 21 G.2, Screen P, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[131] SGIP § 3.3; SGIP Attachment 6.

[132] SGIP § 3.4; SGIP Attachment 7.

[133] SGIP § 3.4.2.

[134] SGIP § 3.5; SGIP Attachment 8; FERC Order 2006 at P 44.

[135] SGIP § 3.2.2.

[136] SGIP § 3.3.4; 3.4.5.

[137] CAISO Tariff § 6.4.

[138] CAISO Tariff § 7.1.

[139] CAISO Tariff § 4.0.

[140] CAISO Tariff § 4.4.4; SCE WDAT § 5.8.1.2. PG&E provides for 60 *business days,* which is roughly similar to 90 calendar days. PG&E WDAT Attachment 7, § 7.0 & 9.0.

[141] CAISO Tariff § 4.5.3; SCE WDAT § 5.8.2.3. PG&E provides 60 business days where upgrades are required and 45 business days where only interconnection facilities must be studied. PG&E WDAT Attachment 8, § 7.0.

[142] Rule 21 E.2.b, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[143] Though it should be noted that in California the utilities were rarely able to keep the time allocated for each study due to the increasing volume of requests they were reviewing. This may be the case in other high volume states.

[144] SGIP § 1.6.

[145] *See, e.g.,* www.oatioasis.com/FPC/FPCdocs/GIS_Queue_Table_061212.mht (Florida Power Corporation generator queue); www.oatioasis.com/DUK/DUKdocs/genqueuedetails.pdf (Duke Energy Carolinas generator queue).

[146] *See, e.g., Cal. Independent System Operator Corp.,* FERC Docket No. ER11-1830-000, Transmittal Letter, p. 2 (October 19, 2010) ("[A]s more projects enter the queue, a study backlog develops and becomes increasingly large as more projects enter the queue, because subsequent projects must wait for the results of the studies of any electrically related earlier queued projects to be studied."); *So. Cal. Edison Co.,* Docket No. ER11-2977-000, Transmittal Letter, p. 3 (March 1, 2011) ("SCE similarly estimates that it would take as long as six to seven years to complete the studies for all of the Small Generators currently in the SCE queue."); *Pacific Gas & Electric Co.*, FERC Docket No. ER11-3004-000, Transmittal Letter, p. 4 (March 2, 2011) ("Because each project has its own separate timeline, a study for one project can not be undertaken until the studies for previous, electrically-related projects are completed. As additional small generator interconnection requests enter the queue, a study backlog develops and becomes increasing large.").

[147] *See, e.g., PJM Interconnection, L.L.C.*, Docket No. ER12-1177-000, 139 FERC ¶ 61,079 (2012); *Cal. Independent System Operator Corp.,* Docket No. ER11-1830-000, 133 FERC ¶ 61,223 (2010); *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER08-1169-000, 124 FERC ¶ 61,183 (2008). The approved tariffs are *available at* www.pjm.com/~/media/documents/manuals/m14a.ashx (PJM Manual 14A); www.caiso.com/Documents/AppendixY_2012-04-18.pdf (CAISO Appendix Y); https://www.midwestiso.org/_layouts/MISO/ECM/Download.aspx?ID=19304 (MISO Attachment X).

[148] *See, e.g., So. Cal. Edison Co.*, 135 F.E.R.C. ¶ 61,093 (2011); *Pacific Gas & Elec. Co.*, 135 F.E.R.C. ¶ 61,094 (2011). The approved tariffs are *available at* http://asset.sce.com/Documents/About%20SCE/WholesaleDistributionAccessTariffv3.pdf (SCE Attachment G); www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/tariffs/PGE_Wholesale_Distribution_Tariff.pdf (PG&E Attachment I).

[149] *See* Motion for Approval of Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations, CPUC Docket R.11-09-011, p.7 (March 16, 2012) (recommending that the CPUC consider distribution group studies as part of Phase II of the rulemaking in Docket No. R.11-09-011), *available at* http://docs.cpuc.ca.gov/EFILE/MOTION/162852.PDF.

[150] *See* Interstate Renewable Energy Council's Motion to Intervene in FERC Docket No. ER11-3004-000, Attachment G: Cluster Timeline (slide from January 25, 2011 presentation on "Redefined PG&E WDT Generation Interconnection Proposal: Generation Interconnection Procedures") (March 23, 2011), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12594944.

[151] *See So. Cal. Edison Co.,* 135 FERC ¶ 61,093 at P 28.

Exhibit SCS-5

Coddington, M.H., *et al.* (2008) *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*. National Renewable Energy Laboratory. Technical Report: NREL/TP-581-42675, available at:
www.nrel.gov/docs/fy08osti/42675.pdf.

Exhibit SCS-5

National Renewable Energy Laboratory

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Innovation for Our Energy Future

Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch

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Technical Report
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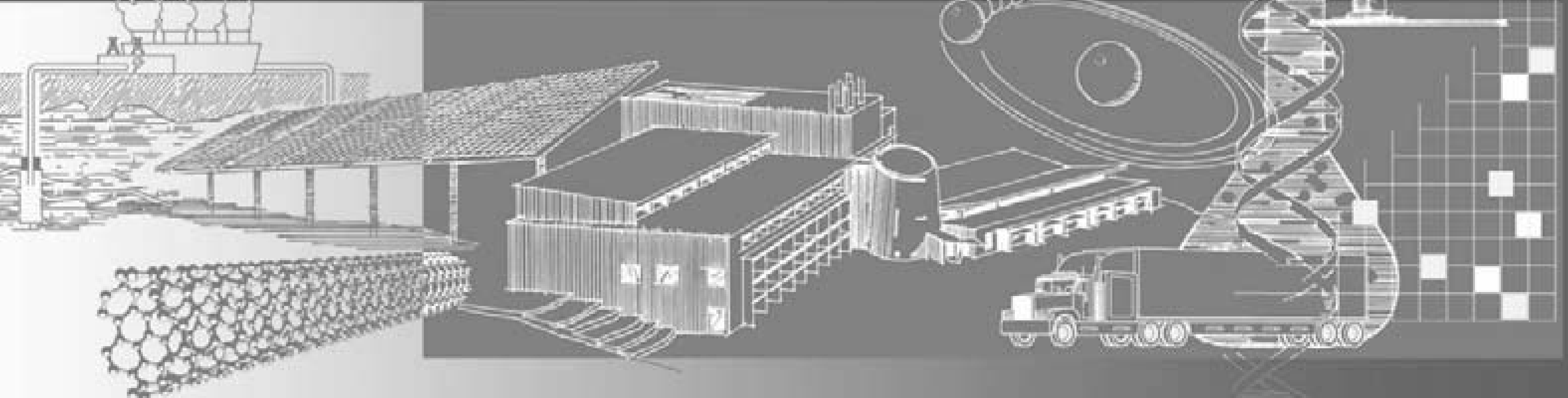

Exhibit SCS-5

Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch

M.H. Coddington, R.M. Margolis, and
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Prepared under Task No. PVB7.6301

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List of Acronyms

AC	alternating current
EDS	external disconnect switch
IEEE	The Institute of Electrical and Electronics Engineers
NEC	National Electrical Code
NESC	National Electrical Safety Code
PG&E	Pacific Gas and Electric
PUC	public utility commission
PV	photovoltaic
SMUD	Sacramento Municipal Utility District
UL	Underwriters Laboratories

Executive Summary

The utility-accessible alternating current (AC) external disconnect switch (EDS) for distributed generators, including photovoltaic (PV) systems, is a hardware feature that allows a utility's employees to manually disconnect a customer-owned generator from the electricity grid. Proponents of the EDS contend that it is necessary to keep utility line workers safe when they make repairs to the electric distribution system. Opponents assert it is a redundant feature that adds cost without providing tangible benefits.

In this paper, we examine the utility-accessible EDS debate in the context of utility-interactive PV systems for residential and small commercial installations. We also evaluate the rationale for EDS requirements. In particular, we focus on the safety, reliability, and cost implications of the EDS. We observe that in a number of states in which public utility commissions (PUCs) and utilities have gained experience with PV systems, they have decided to eliminate the EDS requirement. These decisions typically require that utility-interactive PV systems use inverters that meet relevant Underwriters Laboratories (UL) and Institute of Electrical and Electronics Engineers (IEEE) standards. We argue that, going forward, a number of factors are likely to convince additional PUCs and utilities to eliminate the EDS requirement. These include demonstrated safety and effectiveness of UL- and IEEE-listed inverters, a need to re-evaluate safety practices and rules in light of technological advances and regulatory changes, a desire to reduce the administrative burden of requiring the EDS, and growing pressure to remove barriers to entry for PV systems.

Table of Contents

1. Introduction

Photovoltaic (PV) systems are a maturing technology. In the United States in 2006, the number of installed PV systems exceeded 30,000, and the number is continuing to grow. This paper focuses on residential and small-commercial PV systems that interconnect with the electricity grid. (See Figure 1.)

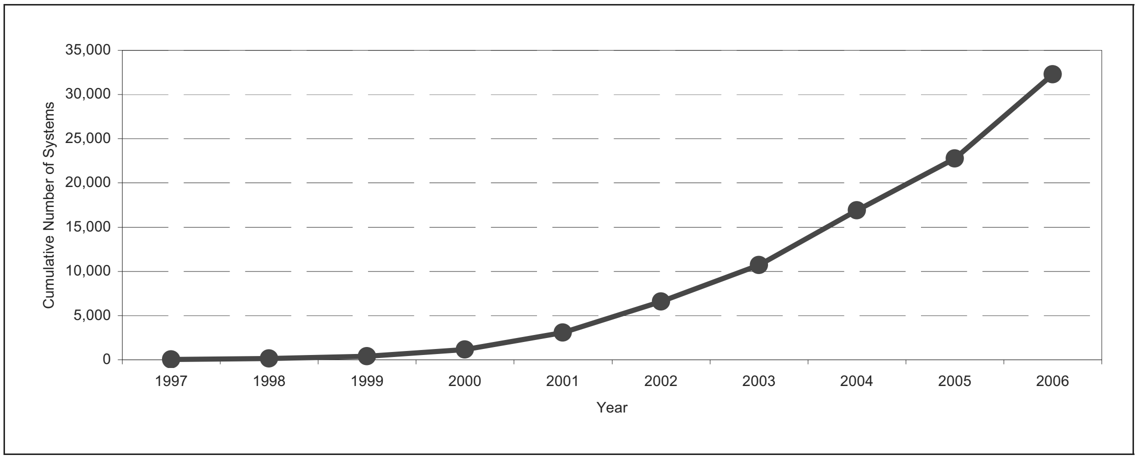

Figure 1. Utility-interactive PV systems installed in the United States, 1997–2006 [1]

Many electric utilities require a customer-owned, utility-accessible external disconnect switch (EDS), often within sight of the revenue meter. This requirement has been an issue of debate among utilities, state public utility commissions (PUCs), and PV system integrators/installers for several decades.

Some people ask: "Why is a utility-accessible EDS necessary? Is it worth the additional cost?" Others ask, "Why take a chance, even if it is remote, with issues of safety and reliability?" Having a utility-accessible EDS for each PV system on a distribution line may allow for maximum safety, but some people question the use of such a device in practical utility operations.

PV systems must meet a variety of codes and standards to be accepted by the local authority having jurisdiction. For example, the National Electrical Code® (NEC) covers all electrical installation requirements on the customer side of the utility revenue meter. Underwriters Laboratories (UL) Standard 1741 [2] covers inverters, which convert direct-current (DC) power to alternating-current (AC) power for use by the customer or utility. The Institute of Electrical and Electronics Engineers (IEEE) Standard 1547™ [3] provides interconnection requirements for PV systems at the point of common coupling and is referenced in the utility connection requirements of UL 1741. In addition, most electric utilities design and operate their electric distribution systems to meet the standards of the National Electrical Safety Code® (NESC), which does not address PV systems directly.

The development of IEEE 1547 and UL 1741 involved varied groups of balloters and contributors (known as working groups). Both standards were developed by groups that included significant utility representation. For example, for IEEE 1547, electric utility representatives comprised 34% of the 230 balloters [4]. UL 1741 also had a significant utility presence in standard development [5].

IEEE 1547, UL 1741, and the NEC do not address the use of customer-owned, utility-accessible EDSs for PV systems. IEEE 1547 does recognize that an EDS is not a universal requirement but that a utility may desire an EDS for its own use. These codes and standards require that PV systems automatically disconnect from the grid in the event of an electric outage. However, many utilities require a redundant utility-accessible EDS in the event of a grid-related problem.

In addition to the utility-accessible EDS, PV systems have several disconnect methods in the event of electric outages, fires, or maintenance. PV systems disconnect from the grid to prevent electricity generated by them from feeding into the grid when a problem occurs on it. Some disconnecting equipment, such as ground fault protection and inverter relays, is automatic. Others—including DC disconnects, inverter DC breakers, inverter AC breakers, EDSs, PV system circuit breakers in customer panels that are backfed, main breakers,[1] utility production meters,[2] and utility revenue meters—are manual. Although the NEC requires a disconnecting means in a readily accessible location, it does not specify that it be outdoors or accessible to utility personnel [6].

Clearly, if a utility-accessible EDS is required, it makes sense for utilities to integrate its use into their standard practices and procedures. Thus, it is worth examining the implications of using EDSs in utility service territories in which there are significant or growing numbers of PV systems and evaluating whether they are a practical tool for enhancing safety.

Several significant issues are involved. First, as the number of PV systems increases, the work and time needed to troubleshoot an outage on a distribution circuit with PV systems (and EDSs) will increase. Second, if utility line workers are required to use a group of EDSs on a line section, the EDSs must be incorporated into switching orders.[3] Third, the geographic information system departments at utilities will need to maintain accurate and timely maps to help dispatchers and line workers locate the EDSs during emergencies. And fourth, if line workers choose to ignore EDS requirements, utilities may face liability in the event of injury or equipment damage and must consider if disciplinary action will be taken.

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[1] Not all homes and businesses have a main disconnect.
[2] Production meters are required by some utilities to track the total energy output of a system.
[3] Switching orders are used by utilities to plan and track the de-energization and re-energization of sections of lines and equipment in a safe manner

Pacific Gas and Electric (PG&E) and Sacramento Municipal Utility District (SMUD), both major electric utilities in California, changed their policies for inverter-based PV systems. Their decisions to eliminate utility-accessible EDS requirements for smaller PV systems were based on expected cost and time savings for the utilities and their customers. These utilities have a large and growing number of customer-sited PV systems to consider, and the EDS requirement was delaying installations and multiplying administrative costs.

It is worth noting that PG&E has the most interconnected PV systems in the United States and SMUD has been one of the most aggressive adopters of PV technology in the country. The fact that these utilities have eliminated their EDS requirements is likely indicative of a trend. As other electric utilities gain experience with PV technology and a better understanding of the safety features required by the UL and IEEE standards for PV inverters, they are likely to follow PG&E and SMUD and eliminate their utility-accessible EDS requirements.

2. Safety, Reliability, and Cost: Prime Focal Points for Utilities

Utilities have an "obligation to serve"[4] in a safe, reliable, and economical manner. The incorporation of utility-accessible EDSs into utility operations has implications for many of the utility's core considerations.

2.1. Safety

Electric utilities supply a commodity that has inherent danger. Line workers understandably believe that no task is more important than maintaining a safe workplace. In an emergency, all line workers are assigned duties to restore the system as quickly and safely as possible. As they work to restore power, they must be extremely cautious. U.S. electric utilities typically follow the NESC[5] for safe working practices to establish proper clearances and safeguard persons from hazards in the installation, operation, and maintenance of electric distribution systems.

Line workers must "consider the electric supply equipment and lines to be energized, unless they are positively known to be de-energized."[6] If a line worker determines that other sources are feeding the circuit, he must locate and open the source or work the line energized.

2.2. Reliability

There is an increasing demand on utilities and PUCs to reduce outage durations.[7] Some utilities face significant fines and penalties if they fail to meet standards set by their state PUCs. Public scrutiny is a driving factor as well. Prolonged outages cause repercussions for utility customers, and in turn the utility, which may result in an increase in complaints to PUCs.

Although safety is the highest priority for utility line workers, restoring power quickly and efficiently is also important. Although the presence of a utility-accessible EDS for PV systems on distribution lines may allow increased protection for utility personnel, it can be questioned if the device would be used by the utility, especially in the event of a large system outage.

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[4]A public utility's duty to serve has its origins in common law principles. See [8].
[5]The NESC is a publication of IEEE (Accredited Standards Committee C2-2007).
[6]Per the NESC Section 42 420.D "Energized Unknown Conditions."
[7]Two nationally recognized and published reliability indices are the System Average Interruption Duration Index and the Customer Average Interruption Duration Index. The System Average Interruption Duration Index is an index of the average system outage duration over a 12-month average. The Customer Average Interruption Duration Index is an index of the average outage duration per customer over a 12-month average.

2.3. Cost

Operating a distribution system in a cost-effective manner is a goal for all utilities. There is immense pressure from ratepayers and PUCs to keep costs down and rates reasonable while maintaining safety and reliability. Every procedure that a line worker must complete must be examined carefully, as it will affect the cost of service. The time expended operating a group of EDSs must be scrutinized, and a decision must be made regarding whether to use these devices.

If a utility or PUC requires the installation of an EDS and it is incorporated into the utility's operational procedures, there is a significant cost to the utility and ratepayers. This is true even if the full cost of the EDS equipment is paid for by the PV system owner. Additional utility operational costs translate into higher electricity rates because those expenditures are typically recovered from ratepayers.

Although beyond the scope of this paper, it would also be useful to evaluate the full cost of inspecting, mapping, and using the EDS from the utility perspective to provide a realistic estimate of its effect on rates/tariffs.

3. Integrating Customer Photovoltaics into a Utility Distribution System

Utilities have historically relied on power sources such as coal, water, nuclear energy, oil, and natural gas to generate electricity. Their generation stations tie directly into the utility transmission system, and power is then transported to area substations and distributed over local distribution feeders. (The entire system is commonly referred to as the "grid.") In the traditional model, power flows in one direction: from the substation to the customer location. The grid was designed to operate safely following this model. Careful supervision and operation helped the utility operate a relatively safe and reliable electricity delivery system.

PV and other distributed generation technologies, however, introduce two-way power flow onto the grid, which raises a number of potential issues for grid operation and maintenance. The UL and IEEE standards were developed to enable distributed generators to operate safely and reliably with the grid.

3.1. Interconnection Standards: UL 1741 and IEEE 1547

UL is a nationally recognized testing laboratory that tests to standards for electrical equipment, primarily to ensure safety of consumer products. The UL listing relevant to EDSs is UL 1741 (2005), Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources. UL 1741 was initially published May 7, 1999, and the latest version includes significant revisions.

UL 1741 applies to inverters, the devices that convert the DC electricity output from solar PV cells into AC, which is used in homes and businesses. Based on IEEE 1547 requirements, UL-listed inverters for PV systems require the inverter to disconnect automatically from the grid.

3.2. Modern Electronic Inverters

Modern small-commercial and residential PV systems include UL-listed components that meet rigorous standards. Inverter technology has advanced considerably in the past decade, and new inverters are required to meet the stringent standards of UL 1741 and IEEE 1547. The NEC requires that an inverter de-energize its output upon loss of utility voltage and remain in that state until utility voltage has been restored [6]. Modern electronic inverters are reliable, intelligent, and comprehensively tested to ensure they do not backfeed to the grid during an outage.

Modern electronic inverters used in PV systems must meet UL 1741 standards to be "listed and labeled." UL 1741 incorporates IEEE 1547 requirements and IEEE 1547.1 [7] procedures for utility-interactive inverters. The NEC also requires that the system "shall automatically de-energize its output to the connected electrical production and distribution network upon loss of voltage in that system and shall remain in that state until the electrical protection and distribution network voltage has been restored" [6]. Numerous independent laboratories, including the National Renewable Energy Laboratory and Sandia National Laboratories, have tested and evaluated a variety of PV components and found that UL-listed inverters perform reliably, as specified.

In the case of an emergency when the grid is down, UL-listed inverters sense a situation known as “islanding”[8] and automatically disconnect if the utility source is absent. Under all abnormal or grid-outage conditions, a UL-listed inverter disconnects in 2 seconds or less and only reconnects after 5 minutes of normal utility conditions.

A manual utility-accessible EDS will require line workers to travel to homes and other buildings with utility-interactive PV systems and manually open the switches. In terms of response, a UL-listed inverter is obviously much faster because it disconnects from the grid quickly and without the need of human intervention.

[8] In this situation, islanding is unintentional. Islanding is a condition in which a portion of an area electric power system is energized by one or more local electric power systems while separated from the rest of the area electric power system. See [3] for additional information about islanding.

4. Defined Purpose of a Utility-Accessible External Disconnect Switch

The purpose of the utility-accessible EDS, from the utility perspective, is to enable line workers to lock out a customer source of power that could feed back onto the grid while utility line workers are working. In this context, a utility-accessible EDS could be used:

- When there is a specific customer-based problem and the utility wants to isolate that customer from the grid
- During the installation phase of new construction
- When line workers are replacing aged or damaged equipment on the utility's system
- During an unplanned electric outage (i.e., a "trouble" situation).

Figure 2. A typical residential PV installation includes (1) an EDS, (2) a DC disconnect, (3) an Inverter (with AC and DC breakers shown in the red circle), and (4) a revenue meter

Photo courtesy of Nicholas Lenssen.

Figure 2 illustrates the variety of equipment that could isolate the PV system from the utility grid. As shown, a typical PV installation has four options for a line worker to disconnect the system (in addition to the EDS). This is an example of a system with most of the system equipment installed outdoors, but some systems include equipment that is mounted indoors.

There are several means of disconnecting power in a typical PV system. The NEC requires (with some exceptions) that most systems have ground fault protection on the DC side of the inverter. The NEC also requires that the system have a means of disconnecting the system on the DC side of the inverter and the AC side of the utility-interactive inverter. In addition, the NEC states that a “disconnecting means shall be installed at a readily accessible location either outside of a building or structure or inside nearest the point of entrance of the system conductors.” Ungrounded conductors may be disconnected by either a switch or circuit breaker, per the NEC [6].

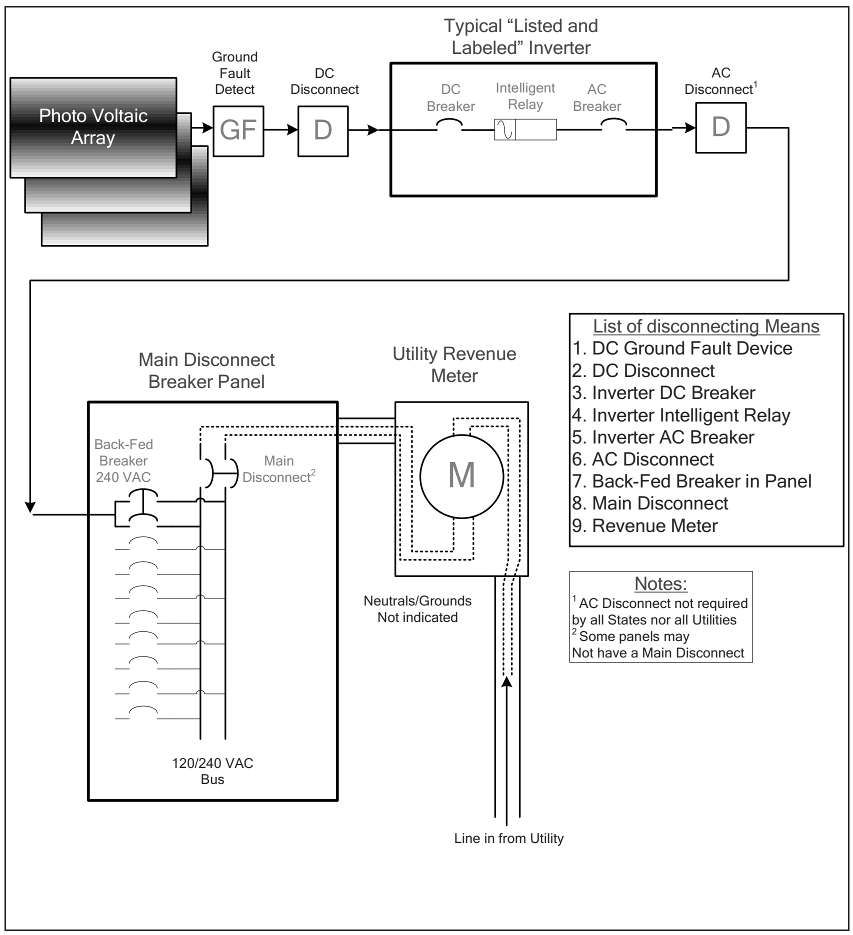

Figure 3. Typical residential/small commercial PV system schematic

It is important to note that there are at least six manual and automatic disconnect devices in a PV system. In Figure 3, there are nine means of disconnecting the PV system from the grid:

- Ground fault protection at or near the PV array[9]
- The DC disconnect switch between the PV array and the inverter
- The inverter DC breaker
- The inverter relay (This is an automatic device that disconnects the inverter if UL 1741 conditions are not met.)
- The inverter AC breaker
- The AC EDS
- The backfed circuit breaker (on the customer panel)
- The main disconnect (Not all buildings have a main disconnect.)
- The utility revenue meter (This historically has been used by utilities as a means of disconnecting customers for a variety of needs.).

Although the NEC contains specific requirements for a readily accessible disconnect switch, it does not require that it be installed outdoors.

[9] NEC-2008 690.5 “Ground Fault Protection” states requirements for ground fault protection.

5. Utility Line Practices

5.1. New Construction

New construction, whether it is overhead or underground, is usually performed while equipment is de-energized. Because there is a risk that a line could be energized during installation, equipment is grounded as a matter of procedure. Line workers are required to test and ground the line before they begin work to ensure they do not contact a live line and risk injury or death [9].

5.2. Customer-Related Problems

It is essential that utilities have the ability to isolate sources of problems on their systems, whether they are at the generation, transmission, or distribution level or a customer location. In normal business practice, if a utility worker believes there is a problem behind a customer's meter, the utility contacts the customer to resolve the problem. Only in unusual situations will utility personnel disconnect a customer by using the main disconnect or removing the revenue meter.

5.3. Trouble Situations

Utility line workers typically consider a line to be energized while working a "trouble" situation. This requires that they wear Occupational Safety and Health Administration- and American National Standards Institute-approved protective equipment, such as rubber gloves, fireproof clothing, eye protection, and insulated tools. Because all lines are considered energized during an outage, an EDS should not be necessary.

Utilities are aware that a small generator could be attached to a customer's service and, in error, create backfeed that places line workers in danger. But if a line crew works on an energized feeder, it will avoid injury if the proper procedures are followed. Similarly, when a crew works a line cold, the appropriate ground cables are installed, and the line is tested, it will avoid injury if the proper procedures are followed.

In the event of a feeder outage, a line crew will risk injury from a PV system only if *all* of the following events occur:

1. The inverter fails to disconnect automatically and somehow produces power without the necessary external voltage source present
2. The anti-islanding, voltage, and frequency methods fail in the inverter
3. The load at the output of the inverter matches the connected load of the PV owner and adjacent customers (This is statistically improbable.)
4. The line worker chooses to work the line energized but fails to follow procedures or;
5. The line worker chooses to work the line de-energized but fails to test and ground the line.

Therefore, a very unlikely series of events must occur to place a line worker at risk from a PV system installed without an EDS.

5.4. Normal Restoration of Outages and the Time Factor

In the event of an electric power outage, a utility will dispatch a line worker to:

- Troubleshoot the outage
- Clear the line or cause of outage
- Repair any damage
- Ensure the area that was damaged is now safe
- Restore power.

This process is expected to be completed as quickly as possible to restore power to affected customers. Average electric outage duration times in the United States are often under 2 hours.[10] However, keeping outage duration at less than 2 hours would be a commendable achievement if line workers had to visit each EDS on a feeder.

Because line workers are expected to troubleshoot and restore electric outages quickly, and because the restoration work is accomplished under the presumption that the lines are energized, it is unlikely that a line worker would use an EDS unless required to do so by documented utility switching procedures.

[10] Based on published utility reliability data. For a detailed explanation of reliability indices and published data, see report by LaCommare, K.H.; Eto, J.H. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*." LBNL-55718. Berkeley, CA: Ernest Orlando Berkeley National Laboratory, September 2004. Available at http://certs.lbl.gov/pdf/55718.pdf.

6. Work Practice Integration

When a utility requires a PV system owner to install an EDS, it must establish how the device will be incorporated into standard procedure. For example, if the EDS is tracked, will the utility use its customer information system and geographic information system, and will dispatchers use that information to resolve outages and write switching orders? If a line worker ignores the EDS installation, will the line worker or the utility face punitive damages or disciplinary action?

6.1. Prompt Restoration of Service Imperative

When a utility's distribution network is down, the utility is under intense pressure to restore power to customers as quickly as possible. Yet, if the utility relies on EDSs as part of its safety protocol, then its line workers must use these switches in an emergency or repair to the distribution network. Thus, the line workers must travel to each location with a utility-accessible EDS to lock the switch in the open position before starting repairs. After the repairs have been completed, the line workers must travel to each location and manually close the switch (to restore PV power to that customer). This would add considerable time to the process of restoring power to the grid.

In addition, such emergencies may take place under severe weather conditions, such as freezing rain, high winds, or flooding. Requiring line workers to navigate these conditions to travel to each location may pose additional risk to their safety. They could lose control of a vehicle while driving on ice, be forced to navigate flood waters, or have to contend with fallen tree limbs.

6.2. Other Sources of Power

Line workers must consider a line energized unless it is positively known to be de-energized, per Rule 420 of the NESC [9]. This critical rule takes into consideration that customers may have gas-powered generators tied to their home and businesses. All building supply stores sell gasoline-powered electrical generators and the electrical equipment necessary to properly isolate and power a home or business. However, because it is not mandatory that these systems be registered with the utility—and they are often not inspected by the appropriate authority having jurisdiction—utility line workers must assume they are energized during an electric outage. These generators are designed for standalone use, but they are simple to interconnect without provisions to avert backfeed into the grid.

7. Relative Cost of a Customer-Owned External Disconnect Switch

The installation of a utility-accessible EDS for PV systems has been a contentious issue for several years. Although some utilities and PUCs require an EDS for PV systems, most PV system installers and owners view the EDS as unnecessary in the era of modern inverter-based interconnection. For PUCs, the decision to require—or allow a utility to require—a utility-accessible EDS is a matter of balancing safety, reliability, and cost (to the utility, rate payers, and the PV system owner).

The cost of an EDS, which is typically several hundred dollars, is not insignificant to PV system owners. It is a particularly unwarranted cost if EDSs are required but not incorporated into utility operating procedures. If a utility requires its customers to install utility-accessible EDSs, it should incorporate the devices into its working rules and operations as practical procedure. Further, if EDSs are required for customer-owned PV systems, the utility should validate any problems with customer-owned systems and determine whether the EDSs are beneficial and thus justify their cost.

An illustrative case is documented in a study conducted by Cassandra Kling, a leader in the New Jersey Million Solar Roof Partnership and renewable energy program manager for the New Jersey Board of Public Utilities at the time, and Christopher Cook, a consultant [10]. Kling and Cook found that none of the EDSs studied had been used by utility maintenance staff. Furthermore, despite their lack of use, no safety incidents had been reported.

8. Review of Past Utility Commission Decisions Regarding External Disconnect Switches

The Energy Policy Act of 2005 calls for state PUCs (and various "non-regulated" utilities) to consider adopting certain standards for electric utilities. Under Section 1254 of the act, "Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547" and "shall be established whereby the services offered shall promote current best practices in interconnection" [11].

Because Federal Energy Regulatory Commission Order 2006 [12] for the interconnection of distributed generators does not require EDSs, there is no federal policy governing this issue. If a state elects to set policy on interconnection, it usually delegates the authority to create rules to the PUC or similar authority. Each state's PUC has the option to create its own rules.

Some states have ruled that inverter-based interconnections do not need EDSs, while others have ruled that inverter-based interconnections must have utility-accessible EDSs. And finally, some states leave the decision to the electric utilities, which often take the most conservative approach and require EDSs.

8.1. States' Stands on External Disconnect Switches

In the United States, 35 states have interconnection rules for distributed generation systems such as the inverter-based PV systems discussed in this paper. Among these states, 18 require an EDS for all systems, 8 specifically waive the requirement for small systems (that meet specific technical requirements), and 9 leave the decision to utilities. Table 1 provides a detailed overview of interconnection rules by state.

Table 1. Interconnect Requirements by State

State	Year	Comments
Alabama	NA	No state rules in effect
Alaska	NA	No state rules in effect
Arizona	2007	No state EDS requirement; utility discretion http://www.azcc.gov/utility/electric/dg.htm
Arkansas	2007	No EDS required for systems that meet conditions (see link) http://www.apscservices.info/rules/net_metering_rules.pdf
California*	2000	No state EDS requirement; utility discretion (SMUD and PG&E have waived the requirement for systems with self-contained meters that meet IEEE 1547, UL 1741, and NEC.) http://www.energy.ca.gov/distgen/interconnection/california_requirements.html

State	Year	Comments
Colorado	2005	No state EDS requirement; Utility discretion http://www.leg.state.co.us/clics/clics2007a/csl.nsf/fsbillcont3
Connecticut	2004	EDS required http://www.dsireusa.org/documents/Incentives/CT06R.doc
Delaware	2000	No EDS required for systems <25 kW http://depsc.delaware.gov/orders/6983.pdf
Florida	2002	No EDS required for systems ≤10 kW http://www.psc.state.fl.us/agendas/archive/071218cc/071218.html
Georgia	2001	No state EDS requirement; utility discretion http://www.dsireusa.org/documents/Incentives/GA04R.htm
Hawaii	2002	EDS required http://www.dsireusa.org/documents/Incentives/HI01Rc.pdf
Idaho	NA	No state rules in effect
Illinois	NA	No state rules in effect (Com Ed has decided that EDSs are not required for systems <40 kW.)
Indiana	2005	No state EDS requirement; utility discretion http://www.in.gov/legislative/iac/iac_title?iact=170&iaca=4
Iowa	2007	EDS required http://www.legis.state.ia.us/Rules/Current/iac/199iac/19915/19915.pdf
Kansas	NA	No state rules in effect
Kentucky	NA	No state rules in effect
Louisiana	2005	EDS required; utility may waive the requirement http://www.dsireusa.org/documents/Incentives/LA03Rb.pdf
Maine	NA	No state rules in effect
Maryland	2007	No EDS required for systems that meet IEEE, UL, and NEC http://mlis.state.md.us/2007RS/chapters_noln/Ch_119_sb0595E.pdf
Massachusetts	2006	No state EDS requirement; utility discretion http://masstech.org/DG/02-38-C_Attachment-B_Tariff-Recs_Clean_June-30-2006.pdf
Michigan	2003	EDS required http://www.michigan.gov/mpsc/0,1607,7-159-16377_43420---,00.html
Minnesota	2004	EDS required http://www.puc.state.mn.us/docs/orders/04-0131.pdf
Mississippi	NA	No state rules in effect

State	Year	Comments
Missouri	2007	EDS required http://www.sos.mo.gov/adrules/csr/current/4csr/4c240-20.pdf
Montana	1999	No state EDS requirement; utility discretion http://www.deq.state.mt.us/energy/Renewable/NetMeterRenew.asp
Nebraska	NA	No state rules in effect
Nevada	2003	No EDS required for systems <10 kW that meet IEEE, UL, and NEC http://www.leg.state.nv.us/Nrs/NRS-704.html#NRS704Sec774
New Hampshire	2001	No EDS required for systems <10 kW http://www.puc.state.nh.us/Regulatory/Rules/puc900.pdf
New Jersey	2004	No EDS required for systems <2 MW http://www.dsireusa.org/documents/Incentives/NJ11R2.htm
New Mexico	2007	EDS required; utilities may allow meter to serve as EDS http://www.nmcpr.state.nm.us/NMAC/parts/title17/17.009.0570.htm
New York	2004	EDS required http://www.dsireusa.org/documents/Incentives/NY02Rc.pdf
North Carolina	2005	EDS required http://www.dsireusa.org/documents/Incentives/NC04Rb.pdf
North Dakota	NA	No state rules in effect
Ohio	2007	EDS required http://dis.puc.state.oh.us/TiffToPDf/A1001001A07C28B45049D31500.pdf
Oklahoma	NA	No state rules in effect
Oregon	2007	No state EDS requirement; utility discretion http://apps.puc.state.or.us/orders/2007ords/07-319.pdf
Pennsylvania	2006	EDS required (can be inside and accessed using a lock box) http://www.dsireusa.org/documents/Incentives/PA07Rb.doc
Rhode Island	NA	No state rules in effect (Narragansett Electric does not require EDSs.)
South Carolina	2006	EDS required http://www.dsireusa.org/documents/Incentives/SC05R.pdf
South Dakota	NA	No state rules in effect
Tennessee	NA	No state rules in effect
Texas	2007	EDS required http://www.puc.state.tx.us/rules/subrules/electric/25.211/25.211ei.cfm

State	Year	Comments
Utah	2002	No EDS required (unless the public service commission deems it necessary) http://le.utah.gov/~code/TITLE54/54_11.htm
Vermont	2006	EDS required http://www.state.vt.us/psb/rules/OfficialAdoptedRules/5500_Electric_Generation_Interconnection_Procedures.pdf
Virginia	2000	No state EDS requirement; utility discretion http://leg1.state.va.us/cgi-bin/legp504.exe?000+reg+20VAC5-315-40
Washington	2006	EDS required; utilities may waive the requirement http://www.wutc.wa.gov/energy
West Virginia	NA	No state rules in effect
Wisconsin	2004	EDS required http://www.legis.state.wi.us/rsb/code/psc/psc119.pdf
Wyoming	2001	EDS required http://legisweb.state.wy.us/statutes/statutes.aspx?file=titles/Title37/T37CH16.htm
Washington DC	2003	No jurisdictional EDS requirement; utility discretion http://dceo.dc.gov/dceo/cwp/view,a,3,q,601821.asp

*California does not require EDSs for very small systems (<1 kW). Because most utility-interactive PV systems are larger than 1 kW, the EDS requirement for PV systems is left to utility discretion, for all practical purposes.

Source: Database of State Incentives for Renewable Energy (www.dsireusa.org), accessed during December 2007. Additional information was collected from state utility commission Web sites and utility Web sites.

The following summarizes the status of the EDS issue in select states:

- **Arkansas**
  The Arkansas Public Service Commission decided in 2002 that a “redundant visible, manual, lockable disconnect switch” was not required for customers that meet the IEEE 1547 standard, have installed the system properly, and operate the system as designed. Commission staff and each utility present asked for the switch, but the commission ruled the IEEE requirements were sufficient [13].
- **Colorado**
  Colorado passed HB07-1169 in 2007 and left the decision of utility-accessible EDSs up to the utilities. (This applies to investor-owned utilities, municipal utilities, and cooperatives). The largest utility in the state, Xcel Energy, requires EDSs for systems of all sizes.

- **Delaware**
  Delaware enacted a rule in July 2007 that allows inverter-based systems of 25 kW or less to be exempt from utility-accessible EDS requirements:

  > All inverter-based systems with a generating capacity of 25 kilowatts (kW) or less must comply with IEEE 1547 and UL 1741, in addition to Delmarva's technical guidelines. These installations are exempt from the pre-interconnection study. Furthermore, an EDS is not required for smaller inverter-based systems. (In emergencies, the utility reserves the right to disconnect the system without notification.) The customer accepts full responsibility for any risks involved with disconnecting the system" [14].

- **Florida**
  On Dec. 7, 2007, the Florida Public Service Commission ruled that inverter-based systems 10 kW or smaller are not required to have an EDS installed if they meet IEEE 1547 and UL 1741 requirements. However, if a utility insists on an EDS, the utility must pay for the full cost of the EDS. Systems larger than 10 kW are required to have an EDS.

- **Nevada**
  The Nevada PUC ruled in 2003 that if IEEE, NEC, and UL requirements are followed, the utility may not require additional devices such as an EDS. The commission's rule states that a "utility is prohibited from requiring certain customer generators to meet additional requirements" [15]. If customers abide by IEEE 1547, UL 1741, and NEC requirements, no additional controls, tests, or insurance are required.

- **New Jersey**
  In New Jersey, utilities contended that EDSs should be required for safety. The New Jersey Board of Public Utilities took great interest in the issue and invited several line workers to testify [16]. When asked if they had ever used an EDS, not one line worker said yes. Although utilities in New Jersey advocated for required EDSs, the board ruled against the requirement.

- **Virginia**
  The Virginia State Corporation Commission ruled that each electric distribution utility could make its own decision about EDS requirements. The commission ruled that PV systems that meet the NEC, IEEE 1547, and UL 1741 requirements are not required to have any additional safety equipment. However, a utility's net-metering tariff may require that customer generators include a utility-accessible EDS. The commission provided no criteria to the utilities with which to make the decision [17].

8.2. Forces That Shape External Disconnect Switch Policy

A combination of forces and stakeholders—including utilities, PUCs, solar-focused policies, and the solar industry itself—shape the direction of EDS-related policies.

In the past, PUCs have frequently been closely aligned with utilities with respect to the EDS issue and therefore have required utility-accessible EDSs based on the perceived need for additional safety. However, PUCs and utilities are changing their positions as they become more informed about existing interconnection standards, modern inverters, and real-world experience with utility-interactive PV systems. The accumulation of knowledge from utilities' experiences, such as that of PG&E and SMUD, will likely influence additional PUCs and utilities to consider different policies going forward. Given the pace of the state regulatory process, it is not surprising that standards and technology have evolved more rapidly than regulatory policy in many states.

Another factor that could hasten elimination of the EDS is government support for expanding PV markets. The most prominent example is the California Solar Initiative. Reaching the California Solar Initiative's goal of installing 3 GW of distributed PV systems in California by 2016 will require increasing emphasis on removing barriers to entry for PV at all levels, reducing installed system costs, and improving program administration. All of these pressures point toward removing the EDS requirement. As other states develop initiatives focused on expanding PV markets, whether to meet renewable portfolio standards or other policy purposes, similar pressures will likely emerge.

Finally, the solar industry's stance is that the utility-accessible EDS is redundant, adds unnecessary cost, increases operational complexity, and hampers market deployment of PV. Solar stakeholders argue that modern UL-listed inverters have virtually eliminated risk for utility line workers and that with the more than 30,000 interconnected PV systems in the United States, there has not been a single line worker injury caused by an inverter-based PV system [18]. As the PV industry grows, it will likely begin to play a stronger role in policy debates at the state and federal levels.

8.3. Implications for Utilities

The combination of well-developed standards, improved technology, and market experience is modernizing regulatory and utility policy with respect to the EDS issue. It is providing an open, technical-based, fresh look at decision-making. Over the next 5–10 years, additional utilities and PUCs will likely eliminate their requirements for utility-accessible EDSs for relatively small (i.e., tens to hundreds of kilowatts) utility-interactive PV systems. At least three factors will push utilities in this direction: a desire to streamline business processes, pressure to remove barriers to entry, and a need to re-evaluate safety practices and rules in light of technological and regulatory changes.

Because of the increasing number of interconnections involving distributed PV systems, utilities will need to streamline their interconnection business processes. Although interconnecting a few installations annually requires limited utility resources, as the number of installations grows—from dozens to hundreds and then to thousands annually—the administrative burden and associated costs will increase quickly. Depending on the regulatory arrangement, the additional costs of processing and approving the installation of an EDS may be borne by the customer (increasing the PV system cost) or the utility (increasing electricity rates for all customers). As the number of systems grows, there will be increasing pressure from rate payer interest groups and regulators to reduce or eliminate utility costs associated with the installation and tracking of EDSs in the service territory.

9. Changing Policy Climate

Although many states require utility-accessible EDSs for PV systems, the policy climate may be changing. As previously noted, two major utilities in California—which have significant installed bases of interconnected PV systems—changed their policies by removing their requirements for utility-accessible EDSs for utility-interactive PV systems.

Both Pacific Gas & Electric (PG&E) and Sacramento Municipal Utility District (SMUD) have been pioneers by adopting significant levels of PV generation into their distribution systems for more than a decade. Based on their experience with PV systems, both utilities changed their EDS rules. (See press releases for SMUD [19] and PG&E [20].) In short, they see EDSs as redundant safety features that add cost to PV installations and may act as a barrier to entry for PV systems. In addition, SMUD and PG&E have become confident that the listed and labeled systems operate properly when there are system problems. Finally, and one of the largest benefits of eliminating the EDS for the utilities, was the administrative cost savings realized from the utilities not having to check plans, validate installation locations, and track the devices in customer information systems and geographic information systems.

10. Conclusion

In this paper, we have examined the interplay between evolving technology and standards and changing perceptions of the need for utility-accessible EDSs and related regulations. Although utility arguments for requiring utility-accessible EDSs for grid-connected PV systems may have been justifiable 5 or 10 years ago, today the EDS issue is effectively addressed by UL and IEEE standards.

Going forward, at least four factors are likely to convince additional utilities and PUCs that EDSs are redundant and unnecessary:

- Increasing utility experience with utility-interactive PV systems that demonstrates the effectiveness and safety of UL-listed inverters
- Re-evaluation of safety practices and rules in light of technological advances and regulatory changes
- A desire to reduce or eliminate the administrative burden and associated cost of requiring utility-accessible EDSs
- Growing pressure to remove barriers to entry to meet growing state-level targets for PV installations.

Put simply, the utility-accessible EDS is increasingly viewed as redundant and unnecessary for residential and small-commercial PV systems with UL-listed inverters. Eight state PUCs (i.e., Arkansas, Delaware, Florida, Maryland, Nevada, New Jersey, New Hampshire, and Utah) have reached this conclusion and eliminated their EDS requirements for systems that meet criteria, and nine state PUCs have decided to leave the EDS decision up to individual utilities. In the states with utility choice, at least five utilities have eliminated the EDS requirement. These states and utilities accounted for more than 80% of total installed PV capacity in the United States in 2006.

If states and utilities deem renewable energy systems viable and desirable, then these entities must minimize economic barriers to system deployment while maintaining safe, reliable, and cost-effective utility service. Eliminating the economic and operational burdens of redundant equipment will encourage greater consideration of renewable energy systems by customers. Because many states have aggressive renewable energy goals, they must examine all potential barriers closely and make informed decisions regarding expensive and redundant equipment.

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Exhibit SCS-5

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14. ABSTRACT *(Maximum 200 Words)*
The utility-accessible alternating current (AC) external disconnect switch (EDS) for distributed generators, including photovoltaic (PV) systems, is a hardware feature that allows a utility's employees to manually disconnect a customer-owned generator from the electricity grid. This paper examines the utility-accessible EDS debate in the context of utility-interactive PV systems for residential and small commercial installations. It also evaluates the rationale for EDS requirements.

15. SUBJECT TERMS
external disconnect switch; EDS; interconnection; photovoltaics; PV; distributed energy; distributed energy resources; DER; DG

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Exhibit SCS-6

Utility External Disconnect Switch

Practical, Legal, and Technical Reasons to Eliminate the Requirement

Prepared by

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Interstate Renewable Energy Council

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Solar America Board for Codes and Standards Report

Utility External Disconnect Switch:

Practical, Legal, and Technical Reasons to Eliminate the Requirement

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Interstate Renewable Energy Council

September 2008

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Exhibit SCS-6

Executive Summary

Some states and utilities require that a utility external disconnect switch (UEDS) be installed between a photovoltaic (PV) power system and the utility grid as a device necessary for safety. Adding the UEDS provides a utility worker with an additional means of disconnecting a customer's system.

However, thousands of PV systems in many jurisdictions have been connected to the utility grid both safely and effectively without a UEDS. Indeed, there is increasing evidence that UEDSs are seldom, if ever, used. The history of safety recorded from these jurisdictions demonstrates that when PV hardware meeting Underwriters Laboratories (UL) and Institute of Electrical and Electronic Engineers (IEEE) standards is installed in compliance with the *National Electrical Code® (NEC)* and operated according to procedures mandated by OSHA and in accordance with recognized Best Practices, the UEDS is not needed to ensure safe operation of a PV system. In fact, for properly designed and installed Code-compliant PV systems, the UEDS provides little, if any, additional safety, beyond what is already present. Indeed, utilities increase their risk of liability when they require the UEDS for safety during maintenance or emergency.

Currently, eight states—Arkansas, Delaware, Florida, Nevada, New Jersey, New Hampshire, North Carolina, and Utah—have incorporated provisions into their interconnection procedures that appear to waive the requirement for a UEDS for small, inverter-based systems. Although the precise application of these provisions may be subject to debate, it is clear that an increasing number of states have decided to do away with the requirement for a UEDS for small, inverter-based systems. In addition, many utilities around the country have also eliminated the requirement for the UEDS on systems less than 10 kW. This list of utilities includes Pacific Gas and Electric and Sacramento Municipal Utility District (SMUD) in California and National Grid USA in the northeast United States. Importantly, more than half of all small, inverter-based photovoltaic systems installed in 2007 were in these jurisdictions with no UEDS requirement.

This report documents the safe operation of PV systems without UEDSs in several large jurisdictions and explains why, increasingly, the Best Practice is to eliminate the UEDS requirement. As described in this report, the UEDS fails to provide the "fail safe" protection that is its justification, is functionally redundant to the traditional practice of "pulling the meter," and adds unnecessary cost to a PV system. This report recommends adherence to established Best Practices for PV system interconnection because they provide safety without the UEDS or its unfavorable impacts.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Introduction

What is a Utility External Disconnect Switch?

Photovoltaic (PV) systems are designed to operate as electric power generators, connected in parallel with the utility grid, and to meet stringent equipment and interconnection standards. A utility-interactive inverter serves as the interface for the PV system providing voltage and frequency synchronization and serving as the system controller. The inverter converts the DC power produced by the PV array into AC power in harmony with the voltage and power quality requirements of the utility grid. This harmonious voltage and frequency synchronization requires the existence of the utility AC power as a reference signal. The grid-interactive inverters are designed to shut down in the absence of utility power.

In the United States, the *National Electric Code® (NEC)* and authorities having jurisdiction (AHJ) require that grid-interactive PV inverters meet the safety and operational requirements of Underwriters Laboratories (UL) standard 1741[1] in addition to the interconnection requirements of Institute of Electrical and Electronic Engineers (IEEE) standard 1547-2003[2]. These standards describe the safety, system protection, and power quality requirements that the inverter must meet. As noted above, these standards also specify operational requirements for safe operation when the inverter is connected to the grid. UL 1741 test standard evaluates inverters for compliance with the IEEE 1547 interconnection requirements to automatically prevent the PV source from supplying power to the grid when the utility grid is not energized.

Figure 1: Typical location of Utility External Disconnect Switch, marked with a yellow caution label, below the production meter. The revenue meter is to left.

A Utility External Disconnect Switch (UEDS) is a disconnect device that the utility uses to isolate a PV system to prevent it from accidentally sending power to the utility grid during routine or emergency maintenance. The UEDS is installed in an accessible location for operation by utility personnel. Figure 1 shows the UEDS in a typical installation. However, meter locations on buildings vary, depending upon local zoning law and utility practices, and line workers seeking to disconnect PV systems in an emergency, may find it difficult to locate the meter and the UEDS. For example, they could be mounted on a wall behind bushes or other obstructions. Also, emergencies often occur during inclement weather or at night.

Historical Background on Distributed Generation

Utilities have historically treated customer-sited generation equipment connected to the grid with similar scrutiny as their large central power plants. Since there is a wide variety of generator types and installations, this common approach may cause excessive interconnection requirements for small, inverter-based generating systems. Central power plants are synchronous generators that export large amounts of power on high-voltage transmission lines. In contrast, small renewable energy systems are inverter-based sources that connect relatively small generators of power to the low-voltage side of the distribution transformer. Some utilities require distributed resources to provide direct-transfer trip, Supervisory Control And Data Acquisition (SCADA), and redundant relay protection devices such as those used by central power plants. Over the past decade, standards and codes have been updated to facilitate the safe operation of small distributed energy systems. Inverters and other equipment meet these newer standards. Many utilities now have different rules and procedures for small distributed systems than they have for central power plants.

1 UL 1741(2005) Inverters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources

2 IEEE 1547 (2003), IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

Current Status of the Utility External Disconnect Switch Requirements

Several utilities (such as National Grid[3], Pacific Gas and Electric[4] (PG&E) and Sacramento Municipal Utility District[5] (SMUD)) and eight states (Arkansas, Delaware, Florida, Nevada, New Jersey, New Hampshire, North Carolina, and Utah)[6] have waived the requirement for a UEDS for small, inverter-based systems. Increasingly, utilities such as PG&E and SMUD are taking advantage of self-contained meters as the means for facilitating the desired accessible/visible break/lockable functions without requiring a UEDS. As a result, more than half of all photovoltaic installations in the US in 2007 were installed without a UEDS[7].

Utility testimony indicates that, for properly designed and installed Code-compliant PV systems, the UEDS provides little, if any, additional safety, when a self-contained meter is already present[8]. There remain state and utility interconnection rules and guidelines that still require an accessible, lockable, visible-break safety-disconnect switch (for example[9,10]). Some utility companies are reluctant to accept the growing body of evidence that this additional safety device is unnecessary.

Review of Literature, Standards, and Operations

Safety, OSHA, and ANSI

Safety, in all aspects of PV system installation, interconnection, and operation, is of paramount concern to the Solar ABCs and the continued growth of connecting renewable energy sources to the grid. The Occupation Safety and Health Administration (OSHA) provides the law of the land for electrical safety regulations although utilities may interpret this law in various ways. The OSHA Act of 1970 requires employers to provide employees with a workplace free from recognized hazards known to cause serious physical harm. Sub part S of OSHA 29CFR part 1910, "Standards for General Industry," contains requirements that deal with protection from electrical hazards. Switching and tagging, and lockout/tagout are the primary methods of hazardous energy control. OSHA rules direct utilities to follow three general steps in switching and tagging procedures: first, check to be sure the circuit is dead; second, ground the circuit conductors; and third, work with gloves.

OSHA 1910.269 and provisions of 1910.331 through 1910.335 cover electrical safety work practices. As part of the three-step process to lockout/tagout a line section, OSHA Section 1910.333(b)(2)(iv)(B) states that:

A qualified person shall use test equipment to test the circuit elements and electrical parts of equipment to which employees will be exposed and shall verify that the circuit elements and equipment parts are de-energized. The test shall also determine if any energized condition exists as a result of inadvertently induced voltage or unrelated voltage backfeed, even though specific parts of the circuit have been de-energized and presumed to be safe. If the circuit to be tested is over 600 volts, nominal, the test equipment shall be checked for proper operation immediately after this test.

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3 John J. Bzura PhD. email correspondence. *M.D.T.E. No. 1116-A Canceling M.D.T.E. No. 1088 Effective: April 2, 2007*. February 2008.

4 Pacific Gas and Electric Company. (Nov 2006). AC disconnect switches for inverter-based generation. Retrieved June 12, 2008 from http://www.pge.com/b2b/newgenerator/solarwindgenerators/disconnectswitches

5 "SMUD Waives Switch Requirement for Solar Systems: Move Makes Solar Installations Easier." SMUD, Feb. 21, 2007. http://www.smud.org/news/releases/07archive/02_21solar.pdf

6 Coddington, M.H., Margolis, R.M., & Aabakken, J. (2008). *Utility-interconnected photovoltaic systems: Evaluating the rationale for the utility-accessible external disconnect switch* page 23

7 Larry Sherwood, IREC personal communication July 6, 2008.

8 Public Service of Colorado testimony in Docket 07R-166E that its policy provides field personnel of either pulling the meter or utilizing the EUDS if they choose to disconnect a customer's system page 88

9 Ohio PUCo. Technical Requirement and Parallel Operation of Distributed Generation. page 1.4.2.

10 Exelon Energy Delivery Interonnection Guideslines for Generators 2 MVA or Less.Original: October 31, 2006. Page 8.

In contrast, utility standards for lockout/tagout usually reference the older, less rigorous American National Standards Institute (ANSI) standard Z244.1-2003 procedures. Where OSHA requires that a circuit be measured and verified as de-energized from all sources before servicing, the ANSI standard does not require this. The lack of a requirement to manually check for safe conditions has often been cited as the necessity for an accessible, lockable UEDS. However, OSHA procedures explicitly require the line section to be verified as de-energized prior to all service actions[11].

It is important to note that all grid interactive inverters installed in the U. S. have been tested to the UL 1741 and IEEE 1547 standards (explained below) that include passing the Unintentional Islanding Test, which verifies that the inverter does not operate independent of the utility. This evaluation also tests that these inverters cease to export power when the utility is de-energized.

Since the OSHA procedure must be performed *before* starting any maintenance or emergency work, a line determined to be de-energized and made safe via the OSHA safety procedures by a worker can not become energized by a grid-interactive inverter under any circumstances without reapplication of line voltage from the utility. Hence, since workers must determine that a line is de-energized and attach equipotential grounding before servicing, presence of the UEDS provides little additional protection for line workers.

National Electrical Code Requirements

The *National Electrical Code® (NEC)* requires all buildings or structures to have switches or breakers capable of disconnecting them from all sources of power[12]. The switches must be manually operable without exposing the operator to contact with live parts and must be readily accessible[13]. *NEC* 690.13 states: "Means shall be provided to disconnect all current-carrying conductors of a photovoltaic power source from all other conductors in a building or other structure." In addition, the switches must be permanently marked to identify them as PV system disconnects. In the case of solar generators, the *NEC* requires at least two manual disconnects on the inverter (one AC disconnect switch and one DC disconnect switch). In section 690.64, the *NEC* specifies that PV system inverters must have means for disconnecting AC, either with breakers in distribution panels or fusible switches. The *NEC* does not require that these disconnects be lockable or that they provide a visible-break separation, conditions placed on the UEDS.

More significant is the difference between the *NEC* and the utility in their working definition of the term "readily accessible." From the *NEC* perspective, a circuit breaker panel in the laundry room in a residence is readily accessible to the electrician who would come to repair a PV system (or general house wiring, electric range, etc.). So is the disconnect switch next to the inverter inside of the garage. If the house is locked and no one is home, then the electrician can't get to the breaker or the disconnect—or the inverter—and therefore can't work on the PV system, wiring, range, etc.

Utilities have a different perspective on *readily accessible*—their stated use of the utility disconnect would potentially require emergency access 24 hours a day, 7 days a week. It cannot be locked in a garage or laundry room. Since the utility usually has access to the customer's revenue meter, they typically want or require the PV utility disconnect switch to be located near the meter. Even though the meter may be located inside the house or building (in an area where the utility has 24-hour access), utility accessible locations are usually (though not always) on the building exterior, leading to the PV industry misnomer, *External* Disconnect Switch, rather than the more correct, Utility Accessible Switch designation.

11 OSHA standard interpretations: Recognition of ANSI ASSE Z244.1-2003 "Control of hazardous energy-lockout tag-out and alternative methods" consensus standard. Washington, D.C.: Occupational Safety & Health Administration.

12 National Fire Protection Association, *National Electrical Code (NEC)* 2008 section 690.13

13 ibid section 690.17 (1)

While in some cases the meter location may be a convenient point to connect the PV system—and thus a single switch could serve *NEC* and utility needs—in many cases it can be complicated and expensive to route. At times, it can be difficult to route PV output wires from a location that is both convenient and acceptable under *NEC* requirements (such as inside a garage) to a point acceptable to utilities. Meter locations on buildings vary depending upon local zoning law and utility practices, and line workers seeking to disconnect PV systems in an emergency may find it difficult to locate the meter and the UEDS. For example, they could be mounted on a wall behind bushes or other obstructions. Also emergencies often occur during inclement weather or at night. In those many cases where the *NEC* disconnect located near the inverter does not meet the utility's needs for readily accessible, the UEDS represents a redundant means to disconnect the system from the grid. In addition, this additional wire and equipment also contributes to system losses and potential maintenance concerns.

UL 1741 and Product Safety Evaluations

Safety of Inverter based system Subject to UL Testing under IEEE Standards 1547

The UL 1741 standard covers inverters, multi-mode inverters, converters, controllers, and interconnection systems for use with Distributed Energy Resources (DER). UL 1741 combines product safety requirements with the interconnection system test requirements developed in the IEEE 1547 standard to delineate the specific procedures and criteria for evaluating and certifying distributed generation products. UL 1741 goes beyond IEEE 1547 requirements to include product safety aspects. Rigorous tests must be passed for any inverter to obtain UL 1741 listing.

IEEE 1547 and IEEE 1547.1 were written to become the basis for DER interconnection of 60 Hz systems (i.e., North America voltage and frequency) and were based upon existing criteria for evaluating utility interconnection relays, and upon utility interconnection certification requirements from individual state and local public utility commissions (PUCs). Relays perform the protective functions that are integrated into an inverter. UL 1741 was revised in 2005 to directly reference the IEEE 1547 requirements and IEEE 1547.1 test procedures. IEEE 1547 references IEEE C37.90 and IEEE C62.41, standards that are normally applied to "utility grade" protection relays.

The combination of the UL 1741 and IEEE 1547 standards help to harmonize the utility interconnection requirements and equipment conformance validation across the United States. The IEEE 1547-compliant UL 1741 requirements became effective on May 5, 2007. Underwriters Laboratories Inc. and other Nationally Recognized Testing Laboratories (NRTLs) perform quarterly unannounced manufacturing inspections on the UL 1741 Listed equipment to verify that products continue to be produced in the same manner as when they were originally evaluated and tested. This process is intended to prevent variations in the critical components (hardware and software) that could affect the critical utility interconnection performance of the product.

Traditional Utility Protection Practices Not Evaluated as Rigorously as Inverter Based Interconnection

Unfortunately, utilities have not required that interconnection protection relays be Listed to UL 1741. Utility protection equipment is only required to meet the IEEE 1547.1 testing requirements and lacks the additional safety afforded by product testing and oversight of critical hardware and software that a NRTL listing provides.

PV system inverters today are UL 1741 Listed with anti-islanding feature. Islanding is a situation in which a portion of the electrical grid that contains loads and generation source remains energized even after it is isolated from the remainder of the electrical grid. The traditional utility concern is that the islanded system will suddenly and unexpectedly connect to the grid and re-energize it—or remain energized when the utility believes the portion of the grid in question to be completely de-energized. To be UL 1741 Listed, inverters must pass tests to "successfully demonstrate that their anti-islanding protection methods operate in less than two seconds under a range of conditions expected on the feeder[14]."

There are distributed generation systems designed to operate site loads during utility outages. However, these are for service institutions such as hospitals and other sites that have stand-by generation that is energized during a utility outage. All of these systems have specially designed power transfer systems that prevent the system from energizing the utility grid during an outage.

IEEE Standard Isolation Device Requirement

Some utilities cite the IEEE Standard 1547 Isolation Device clause 4.1.7 as justification for the UEDS[15]. Clause 4.1.7 in IEEE-2003 states: "When required by the Area Electric Power System (EPS) operating practices, a readily accessible, lockable, visible-break isolation device shall be located between the Area EPS and the DER unit." In other words, under IEEE 1547, an isolation device is not a universal requirement, but IEEE 1547 recognizes that utilities could require a redundant disconnect that could be on the utility side of the meter in addition to the many utility methods already available to isolate a circuit. Unless the local jurisdiction rules otherwise, this isolation device clause in IEEE 1547 is not a mandatory equipment requirement.

Operational Issues

Non-Use of the UEDS

Where the UEDS is required for renewable energy systems, discussions with utility personnel show that few utilities have used the switch during maintenance or emergency situations. One research project found that none of the external disconnect switches studied had been used by utility maintenance staff[16].

We will review some of the reasons why utility workers have not operated the UEDS for safety during either maintenance or emergency conditions. First, most residential PV systems are less than 10 kW. Residential customers have a potential connected load above 20 kW. Motor loads in particular tend to trip off isolated PV systems because motors have an in-rush current in the range of 5-12[17] times normal load. Typical motor loads are air conditioning units, washing machines, and refrigerators. If the grid is de-energized, then the PV alone cannot supply the motor load for the residence, and the inverter will shut off.

Second, according to Coddington et al.[18], on the UEDS a line worker can only be injured by a PV system if several failures occur at the same time. Similarly, the California Rule 21 Supplemental Review Guideline[19] states that a number of specific conditions must exist for unintentional islanding to take place. Public Service of Colorado's expert witness on this subject[20] has confirmed that a very unlikely series of events must occur to place a line worker at risk from a PV system installed without a UEDS.

14 Email and conference call with Tim Zgonena, Principal Engineer, Underwriters Laboratories, Inc.

15 Potomac Electric Power Company's Reply Comments Case No 1050,41 May 2,2008 Response to MD-DC-VA Solar Energy Industry Association page 6

16 U.S. Department of Energy, *Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections,* September 2005

17 How to Make Accurate Inrush Current Measurements Mar 1, 2003 , By Bob Greenberg, Fluke Corp

18 ibid Coddington page 11

19 www.energy.ca.gov/distgen/interconnection/SUP_REV_GUIDELINE_20050831.PDF Section 7.1 5a-c

20 Public Utilities Commission State of Colorado Docket 07A-462E Volume 4 page 102

Third, operation of multiple UEDSs is onerous for the utility. Utility companies may be reluctant to follow the number of steps necessary to document the required information necessary to properly switch and tag each PV system. This includes recording the location and size of each PV system on the utility's circuit maps and making this information available to system operators, engineers, line workers, and all non-utility employee crews working on the utility facilities. This is simply not practical in utility operations. In order to do this, information with details of the interconnect agreement must be communicated from the commercial side to the operational side of the utility. In addition, if the UEDS is to be operated for safety during maintenance and emergency situations, then the appropriate switching orders need to be generated for each work group, and all switching and tagging orders for small PV systems need to be posted and incorporated into existing switching and tag-out orders. Finally, although the utility must ensure access to the UEDS just as it does for all metering, utility metering personnel and service personnel are not the same. Service outages on the distribution system come at night or in bad weather conditions when metering personnel are not available to help with locating a UEDS. Thus, some utilities allow the practice of "pulling the meter" to isolate the system[21,22] if the need for isolation is found to be necessary.

Cost

Several PV installers have estimated the typical incremental cost of installing a UEDS to be in the range of $200 to $400. In response to a question from the Florida Public Utilities Commission, Progress Energy estimated the cost of the UEDS to be $1,253.13 per customer[23]. Whether the lesser or the higher estimate, on small systems, the UEDS is a burden that will have long-term impacts with no clear benefits. The national interest requires that our renewable energy installations be completed in as cost effective a manner as possible, consistent with Best Practices including safety concerns.

Legal and Jurisdictional Issues

There are two legal issues that arise from the utilities' claim that the UEDS is necessary for safety. The first issue is the exposure that utilities accept when they "require" the UEDS and then fail to operate it during maintenance or emergency situations. A utility that fails to incorporate the use of the UEDS into its standard operating procedures could as a result be faced with the prospect of additional source of liability or even punitive damages in case of injury[24].

The second issue arises from the fact that the utility requires the line worker to operate the UEDS even though it is located outside the utility's jurisdiction, i.e., it is not utility property and is located on the customer side of the meter. The legal concern arises because utility line workers are considered not "qualified"[25] under *NEC* requirements to work outside the utility's jurisdiction. The utility is exposed to liability if the line worker becomes injured attempting to operate the UEDS.

21 Pacific Gas and Electric Company. (Nov 2006). AC disconnect switches for inverter-based generation. Retrieved June 12, 2008 from http://www.pge.com/b2b/newgenerator/solarwindgenerators/disconnectswitches/

22 Transcript of cross examination of Public Service of Colorado expert witness on this subject in 2008 Public Utility Commission of Colorado Docket 07R-166E page 88

23 Florida Public Utilities Commission (2007). Docket 070674-EI. Tallahassee, FL.

24 ibid Cook

25 National Fire Protection Association. (2007). Report on proposals A2007 NFPA 70. Quincy, MA:

Conclusions

This report highlights how a number of progressive state regulatory commissions and utilities with jurisdiction over a large portion of the country's inverter-based renewable energy systems have eliminated the UEDS requirement traditionally required for interconnection of Distributed Energy Resource generation and how the growing evidence indicates that the UEDS requirement can be eliminated from state and utility requirements for PV systems without compromising the safety of these systems or of personnel working near them.

The disadvantages of the UEDS requirement are:

- The lack of any measurable benefit to safety
- The additional cost of UEDS
- The potentially detrimental impact on PV system losses and reliability
- The possible liability incurred to federal sanctions and penalties as well as to punitive damages.

Furthermore,

- Utilities rarely, if ever, use the installed UEDS
- PV systems installed without a UEDS have had a clean safety record
- More than half of the small PV systems installed in 2007 did not have a UEDS
- A growing number of utility and regulatory commissions have decided to eliminate the UEDS requirement.

Recommendation

The recommendation is to eliminate the requirement for UEDS for all small, inverter-based systems in all jurisdictions. With the inherent safety features built into all UL-listed PV inverters, the UEDS is functionally unnecessary and provides little, if any, additional safety.

For customers with self-contained meters (including almost all residential and small commercial customers), the meter itself is already fully capable of providing the functions required of the switch (i.e., a visible, physical, lockable separation of the system from the utility). At the very minimum, these customers should be excluded from any UEDS requirement.

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www.energy.ca.gov/distgen/interconnection/SUP_REV_GUIDELINE_20050831.PDF Section 7.1 5a-c

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Acronyms

AC	Alternating current
ANSI	American National Standard Institute
AHJ	Authorities Having Jurisdiction
DC	Direct current
DOE	Department of Energy
DER	Distributed Energy Resource
EPS	Electric Power Systems
FERC	Federal Energy Regulatory Commission
IEEE	The Institute of Electrical and Electronic Engineers
IREC	Interstate Renewable Energy Council
NEC	*National Electrical Code®*
NFPA	National Fire Protection Association
NREL	National Renewable Energy Laboratory
NRTLs	Nationally Recognized Testing Laboratories
OSHA	Occupational Safety Health Administration
PG&E	Pacific Gas & Electric
PV	Photovoltaic
SMUD	Sacramento Municipal Utility District
Solar ABCs	Solar America Board for Codes and Standards
UL	Underwriters Laboratories
UEDS	Utility External Disconnect Switch

Glossary of Terms

Best Practice: A technique or methodology that, through experience and research, has proven to reliably lead to a desired result. A commitment to using the Best Practices in any field is a commitment to using all of the knowledge and technology at one's disposal to ensure success.

De-energized: Free from any electrical connection to a source of potential difference and from electrical charge; not having a potential different from that of the Earth.

Intentional Islanding: Intentional islanding is the purposeful sectionalization of the utility system during widespread disturbances to create power "islands." These islands are designed to maintain a continuous supply of power during disturbances of the main distribution system.

Self-Contained Meter: A utility revenue meter that contains all sensing elements within the casing and meter base connections. All power to the facility must pass directly through the meter in order for the facility to receive service. Should the meter be removed, a physical separation will occur between the meter-base blade sockets, and the facility will be isolated from the utility. Nearly all residential customers are served by self-contained meters.

Unintentional Islanding: An unplanned condition where one or more DERs and a portion of the electric utility grid accidentally remain energized through the point of interconnection.

Utility External Disconnect Switch: An isolation device, accessible to utility personnel, used to provide a physical separation between a customer-generator and the utility system. This device must have a visibly-verifiable separation, be lockable in the open position, but does not need to be load-break rated or even be a switch.

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