AUTHENTICATED
U.S. GOVERNMENT
INFORMATION
GPO

FEDERAL REGISTER

Vol. 78 Thursday,
No. 234 December 5, 2013

Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Part 35

Small Generator Interconnection Agreements and Procedures; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[RM13–2–000; Order No. 792]

Small Generator Interconnection Agreements and Procedures

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: In this Final Rule, the Federal Energy Regulatory Commission (Commission) is amending the *pro forma* Small Generator Interconnection Procedures (SGIP) and *pro forma* Small Generator Interconnection Agreement (SGIA) to: Incorporate provisions that provide an Interconnection Customer with the option of requesting from the Transmission Provider a pre-application report providing existing information about system conditions at a possible Point of Interconnection; revise the 2 megawatt (MW) threshold for participation in the Fast Track Process included in section 2 of the *pro forma* SGIP; revise the customer options meeting and the supplemental review following failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer and includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably; revise the *pro forma* SGIP Facilities Study Agreement to allow the Interconnection Customer the opportunity to provide written comments to the Transmission Provider on the upgrades required for interconnection; revise the *pro forma* SGIP and the *pro forma* SGIA to specifically include energy storage devices; and clarify certain sections of the *pro forma* SGIP and the *pro forma* SGIA. The reforms should ensure interconnection time and costs for Interconnection Customers and Transmission Providers are just and reasonable and help remedy undue discrimination, while continuing to ensure safety and reliability.

DATES: This rule is effective February 3, 2014.

FOR FURTHER INFORMATION CONTACT:

Leslie Kerr (Technical Information), Office of Energy Policy and Innovation, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8540, *Leslie.Kerr@ferc.gov*.

Monica Taba (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–6789, *Monica.Taba@ferc.gov*.

Christopher Kempley (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8442, *Christopher.Kempley@ferc.gov*.

SUPPLEMENTARY INFORMATION:

145 FERC ¶ 61,159

Before Commissioners: Philip D. Moeller, John R. Norris, Cheryl A. LaFleur, and Tony Clark.

Final Rule

(Issued November 22, 2013)

Paragraph Nos.

I. Introduction 1
II. Background 4
A. Order No. 2006 4
B. Solar Energy Industries Association Petition and the Notice of Proposed Rulemaking 10
III. Need for Reform 15
A. Commission Proposal 15
B. Comments 16
C. Commission Determination 21
IV. Proposed Reforms 28
A. Pre-Application Report 28
1. Commission Proposal 28
2. Need for a Pre-Application Report 31
a. Comments 31
b. Commission Determination 37
3. Pre-Application Report Fee 41
a. Comments 41
b. Commission Determination 45
4. Pre-Application Report Timeline 47
a. Comments 47
b. Commission Determination 51
5. Pre-application Report Request Form 53
a. Comments 53
b. Commission Determination 56
6. Readily Available Information 57
a. Comments 57
b. Commission Determination 63
7. Other Issues 65
a. Comments 65
b. Commission Determination 74
B. Threshold for Participation in the Fast Track Process 83
1. Commission Proposal 83
2. Comments 84
3. Commission Determination 102
C. Fast Track Customer Options Meeting and Supplemental Review 112
1. Commission Proposal 112
2. General Comments on the Customer Options Meeting and the Supplemental Review 114
a. Comments 114
b. Commission Determination 118
3. Minimum Load Screen (SGIP Section 2.4.4.1) 119
a. Comments 119

Paragraph Nos.

b. Commission Determination 142
4. Voltage and Power Quality Screen and Safety and Reliability Screen (SGIP Sections 2.4.4.2 and 2.4.4.3) 150
a. Comments 150
b. Commission Determination 157
5. Supplemental Review Screen Order (SGIP Section 2.4.2) 163
a. Comments 163
b. Commission Determination 165
6. Supplemental Review Fee (SGIP Sections 2.4.1 and 2.4.3) 166
a. Comments 166
b. Commission Determination 171
7. Process Following Completion of the Customer Options Meeting and the Supplemental Review (SGIP Sections 2.3.1, 2.4.4 and 2.4.5) 175
a. Comments 175
b. Commission Determination 182
D. Review of Required Upgrades 190
1. Commission Proposal 190
2. Comments 191
3. Commission Determination 204
E. Revision to SGIA Section 1.5.4 Regarding Over and Under-Frequency Events 211
1. Commission Proposal 211
2. Comments 212
3. Commission Determination 221
F. Interconnection of Storage Devices 223
1. Commission Proposal 223
2. Comments 224
3. Commission Determination 228
G. Other Issues 233
1. Network Resource Interconnection Service 233
a. Commission Proposal 233
b. Comments 234
c. Commission Determination 236
2. Hosting Capacity 238
a. Comments 238
b. Commission Determination 244
3. Jurisdiction 245
a. Comments 245
b. Commission Determination 247
4. Miscellaneous 250
a. Commission Proposal 250
b. Comments 251
c. Commission Determination 258
V. Compliance 263
A. Commission Proposal 263
B. Comments 266
C. Commission Determination 270
VI. Information Collection Statement 278
VII. Environmental Analysis 283
VIII. Regulatory Flexibility Act Analysis 284
IX. Document Availability 286
X. Effective Date and Congressional Notification 289
Appendix A: List of Short Names of Commenters on the Notice of Proposed Rulemaking
Appendix B: Flow Chart for Interconnecting a Certified Small Generating Facility Using the ''Fast Track Process''
Appendix C: Revisions to the *Pro Forma* SGIP
Appendix D: Revisions to the *Pro Forma* SGIA

I. Introduction

1. In this Final Rule, the Federal Energy Regulatory Commission (Commission) is amending the *pro forma* Small Generator Interconnection Procedures (SGIP) and *pro forma* Small Generator Interconnection Agreement (SGIA) to: (1) Incorporate provisions that provide an Interconnection Customer with the option of requesting from the Transmission Provider a pre-application report providing existing information about system conditions at a possible Point of Interconnection; (2) revise the 2 megawatt (MW) threshold for participation in the Fast Track Process included in section 2 of the *pro forma* SGIP; (3) revise the customer options meeting and the supplemental review following failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer and includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably; (4) revise the *pro forma* SGIP Facilities Study Agreement to allow the Interconnection Customer the opportunity to provide written comments to the Transmission Provider on the upgrades required for interconnection; (5) revise the *pro forma* SGIP and the *pro forma* SGIA to specifically include energy storage devices; and (6) clarify certain sections of the *pro forma* SGIP and the *pro forma* SGIA. The reforms should ensure interconnection time and costs for Interconnection Customers and Transmission Providers are just and reasonable and help remedy undue discrimination, while continuing to ensure safety and reliability.

2. Originally adopted in Order No. 2006,[1] the *pro forma* SGIP and the *pro forma* SGIA establish the terms and conditions under which public utilities[2] must provide interconnection service to Small Generating Facilities[3] of no more than 20 MW. Based on the record in this proceeding, the Commission finds it necessary under section 206 of the Federal Power Act[4] (FPA) to revise the *pro forma* SGIP and the *pro forma* SGIA to ensure that the rates, terms and conditions under which public utilities provide interconnection service to Small Generating Facilities remain just and reasonable and not unduly discriminatory. The Commission believes that taking these actions at this time is in the public interest. The Commission routinely evaluates the effectiveness of its regulations and policies in light of changing industry conditions to determine if reforms are necessary to satisfy its statutory obligation of ensuring just and reasonable and not unduly discriminatory rates, terms and conditions of service.[5] As concerns generator interconnection, regions of the country are experiencing significant penetrations of small generation and increasing requests for small generator interconnection. In Order No. 2006, the Commission anticipated the need to revisit its small generator interconnection regulations as the industry evolves, requesting stakeholders to convene informal meetings ''to consider and recommend consensus proposals for changes in the Commission's rules for small generator interconnection.''[6] The time is ripe to promulgate such changes in light of the increased penetration of small generator resources, the continued focus by states and others on the development of distributed resources,[7] and the need for this Commission to have its regulations and policies ensure just and reasonable rates, terms and conditions of service.

3. The reforms we adopt largely track the proposals set forth in the Notice of Proposed Rulemaking issued in this proceeding on January 17, 2013,[8] with modifications to address suggestions and concerns raised in comments. Among other things, the Commission has revised aspects of the pre-application report requirement, the Fast Track eligibility threshold, and the supplemental review requirement to balance the interests of the Interconnection Customer with those of the Transmission Provider. With these modifications, the Commission concludes that the package of reforms adopted in this Final Rule will reduce the time and cost to process small generator interconnection requests for Interconnection Customers and Transmission Providers, maintain reliability, increase energy supply, and remove barriers to the development of new energy resources. This fulfills our statutory obligation to ensure that rates, terms and conditions for Commission-jurisdictional services are just and reasonable and not unduly discriminatory, as sections 205 and 206 of the FPA require.[9]

II. Background

A. Order No. 2006

4. In Order No. 2006, the Commission established a *pro forma* SGIP and SGIA for the interconnection of generation resources no larger than 20 MW, continuing the process begun in Order No. 2003[10] of standardizing the terms and conditions of Commission-jurisdictional interconnection service. The Commission adopted the *pro forma* SGIA and the *pro forma* SGIP to respond to business and technology changes in the electric industry. Where the electric industry was once primarily the domain of vertically integrated utilities generating power at large centralized plants, the Commission noted in Order No. 2006 that advances in technology had created a burgeoning market for small power plants that may offer economic, reliability or environmental benefits.[11]

5. The *pro forma* SGIP describes how an Interconnection Customer's interconnection request (application) should be evaluated, and includes three alternative procedures for evaluating an interconnection request. These procedures include the Study Process, which can be used by any generating facility with a capacity no larger than 20 MW, and two procedures that use certain technical screens to quickly identify any safety or reliability issues associated with proposed interconnections: (1) The Fast Track Process for certified[12] Small Generating Facilities no larger than 2 MW; and (2) the 10 kilowatt (kW) Inverter Process for certified inverter-based[13] Small Generating Facilities no larger than 10 kW.

6. The Study Process in section 3 of the *pro forma* SGIP, which can be used by any generating facility with a capacity no larger than 20 MW, is used to evaluate small generator interconnection requests that do not qualify for either the Fast Track Process or the 10 kW Inverter Process. The Study Process is similar to the process under the Large Generator Interconnection Procedures (LGIP) set forth in Order No. 2003. The Study Process normally consists of a scoping meeting, a feasibility study, a system impact study, and a facilities study. These studies identify any adverse system impacts[14] that must be

[1] *Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh 'g,* Order No. 2006–A, FERC Stats. & Regs. ¶ 31,196 (2005), *order on clarification,* Order No. 2006–B, FERC Stats. & Regs. ¶ 31,221 (2006).

[2] For purposes of this Final Rule, a public utility is a utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce, as defined by the FPA. *See* 16 U.S.C. 824(e) (2012). A non-public utility that seeks voluntary compliance with the reciprocity condition of an Open Access Transmission Tariff (OATT) may satisfy that condition by filing an OATT, which includes the *pro forma* SGIP and the *pro forma* SGIA.

[3] Capitalized terms used in this Final Rule have the meanings specified in the Glossaries of Terms or the text of the *pro forma* SGIP or SGIA. A Small Generating Facility is the device for which the Interconnection Customer has requested interconnection. The owner of the Small Generating Facility is the Interconnection Customer. The utility entity with which the Small Generating Facility is interconnecting is the Transmission Provider.

[4] 16 U.S.C. 824e (2012).

[5] *See* Plan for Retrospective Analysis of Existing Rules, Docket No. AD12–6–000, *available at http://www.ferc.gov/legal/maj-ord-reg/retro-analysis/ferc-eo-13579.pdf. See also Integration of Variable Energy Resources,* Order No. 764, FERC Stats. & Regs. ¶ 31,331 (2012).

[6] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 118.

[7] Distributed resources are sources of electric power that are not directly connected to a bulk power transmission system. Distributed resources include both generators and energy storage technologies. (Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, p. 3).

[8] *Small Generator Interconnection Agreements and Procedures,* 78 FR 7524 (Feb. 1, 2013) (NOPR), FERC Stats. & Regs. ¶ 32,697 (2013).

[9] 16 U.S.C. 824d and 824e (2012).

[10] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[11] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 9.

[12] *See* Attachments 3 and 4 of the *pro forma* SGIP, which specify the codes, standards, and certification requirements that Small Generating Facilities must meet. Order No. 2006, FERC Stats. & Regs. ¶ 31,180.

[13] An inverter is a device that converts the direct current (DC) voltage and current of a DC generator to alternating voltage and current. For example, the output of a solar panel is DC. The solar panel's output must be converted by an inverter to alternating current (AC) before it can be interconnected with a utility's AC electric system. Such inverters, particularly newer inverters, often incorporate additional power electronics that can provide other safety or power quality functions.

[14] An adverse system impact means that technical or operational limits on conductors or equipment

addressed before the Small Generating Facility may be interconnected as well as any equipment modifications that may be required to accommodate the interconnection. Once the Interconnection Customer agrees to fund any needed upgrades, an SGIA is executed that, among other things, formalizes responsibility for construction and payment for interconnection facilities and upgrades.[15]

7. The Fast Track Process eliminates the scoping meeting and three interconnection studies and instead uses technical screens to quickly identify reliability or safety issues. If the proposed interconnection passes the screens, the Transmission Provider offers the Interconnection Customer an SGIA without further study. If the proposed interconnection fails the screens, but the Transmission Provider nevertheless determines that the Small Generating Facility may be interconnected without affecting safety and reliability, the Transmission Provider provides the Interconnection Customer with an SGIA. If the Transmission Provider does not or cannot determine that the Small Generating Facility may be interconnected without affecting safety and reliability, the Transmission Provider offers the Interconnection Customer the opportunity to attend a customer options meeting to discuss how to proceed. In that meeting, the Transmission Provider must: (1) Offer to perform facility modifications or minor modifications to the Transmission Provider's system (e.g., changing meters, fuses, relay settings) that would allow interconnection and provide a non-binding good faith estimate of the cost to make such modifications; (2) offer to perform a supplemental review if the Transmission Provider concludes that the supplemental review might determine that the Small Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process, where such supplemental review is paid for by the Interconnection Customer, and provide a non-binding good faith estimate of the cost of that review; [16] or (3) obtain the Interconnection Customer's agreement to continue evaluating the interconnection request under the Study Process. If the Transmission Provider determines in the supplemental review that the Small Generating Facility can be interconnected safely and reliably and the Interconnection Customer agrees to pay for any upgrades identified in the supplemental review, the Transmission Provider and the Interconnection Customer execute an SGIA. If, after the supplemental review, the Transmission Provider still is unable to determine that the proposed interconnection would not degrade the safety and reliability of its electric system, the interconnection request is evaluated using the Study Process.

8. The 10 kW Inverter Process is available for the interconnection of certified inverter-based generators no larger than 10 kW. The 10 kW Inverter Process includes a simplified application form, interconnection procedures, and a brief set of terms and conditions (rather than a separate interconnection agreement). The 10 kW Inverter Process uses the same technical screens as the Fast Track Process. If the results of the analysis using the technical screens indicate that the generator can be interconnected safely and reliably, the interconnection application is approved. To simplify the 10 kW Inverter Process, the Interconnection Customer agrees to the terms and conditions of the interconnection at the time the interconnection request is made.[17]

9. The ten technical screens used in the Fast Track and 10 kW Inverter Processes are included in section 2.2.1 of the *pro forma* SGIP. The screen in section 2.2.1.2 of the *pro forma* SGIP, which is referred to in this Final Rule as the 15 Percent Screen, will be discussed at some length below:

> 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 [percent] 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.

B. Solar Energy Industries Association Petition and the Notice of Proposed Rulemaking

10. On February 16, 2012, pursuant to sections 205 and 206 of the FPA and Rule 207 of the Commission's Rules of Practice and Procedure,[18] and noting that the Commission encouraged stakeholders to submit proposed revisions to the regulations set forth in Order No. 2006, the Solar Energy Industries Association (SEIA) filed a Petition to Initiate Rulemaking (Petition) requesting that the Commission revise the *pro forma* SGIA and SGIP set forth in Order No. 2006.[19] In its Petition, SEIA asserted that the *pro forma* SGIP and SGIA as applied to small solar generation are no longer just and reasonable, have become unduly discriminatory, and present unreasonable barriers to market entry.[20] SEIA noted that its Petition applies exclusively to solar electric generation due to its unique characteristics.[21]

11. On February 28, 2012, the Commission issued a Notice of Petition for Rulemaking in Docket No. RM12–10–000, seeking public comment on SEIA's Petition. The Commission received a number of comments, protests, and answers in response.

12. On July 17, 2012, the Commission convened a technical conference in Docket Nos. RM12–10–000 and AD12–17–000 in order to discuss issues related to SEIA's Petition. The Commission received nine post-technical conference comments, including clarifying comments from SEIA.

13. On January 17, 2013, the Commission issued the NOPR in this proceeding, proposing a package of reforms to the *pro forma* SGIA and the *pro forma* SGIP.[22] Commission staff held a workshop on March 27, 2013, at which stakeholders discussed the NOPR proposals. In addition to the Commission staff workshop, some stakeholders formed a stakeholder working group (SWG) to develop revisions to the NOPR proposals.[23] Comments on the NOPR as well as comments generated by the Commission staff workshop were due June 3, 2013. The Commission received thirty-three timely comments, four comments out of time and two reply comments out of time.[24]

14. The stakeholders that participated in the SWG indicated in their comments

are exceeded under the interconnection, which may compromise the safety or reliability of the electric system.

[15] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 44.

[16] The purpose of the supplemental review is to determine if the Small Generating Facility can be interconnected safely and reliably, however, the *pro forma* SGIP does not include details regarding how the Transmission Provider is to perform the supplemental review.

[17] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 46.

[18] 18 CFR 385.207 (2013).

[19] SEIA Petition at 4 (citing Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 118).

[20] *Id.* at 12.

[21] *Id.* at 4 (explaining that solar generation occurs only during daylight hours when peak load typically occurs, and solar photovoltaic technology utilizes inverters with built-in functions that protect the safety and reliability of the electric system).

[22] NOPR, FERC Stats. & Regs. ¶ 32,697. While SEIA's Petition was specific to small solar generation, the NOPR included all Small Generating Facilities.

[23] The SWG included EEI, NRECA, APPA, IREC, SEIA, NREL, and other stakeholders.

[24] *See* Appendix A, List of Short Names of Commenters on the Notice of Proposed Rulemaking.

that the SWG came to agreement on certain revisions to the proposals for the pre-application report and the threshold for participation in the Fast Track Process. The National Rural Electric Cooperative Association, Edison Electric Institute and the American Public Power Association (NRECA, EEI & APPA), the Interstate Renewable Energy Council (IREC), SEIA, and National Renewable Energy Laboratory (NREL) submitted SWG proposed revisions with their comments.

III. Need for Reform

A. Commission Proposal

15. In light of changes in the energy industry since the issuance of Order No. 2006, and based on the comments submitted in response to the SEIA Petition and the July 17, 2012 Technical Conference, the Commission preliminarily found that proposed reforms were needed to ensure that the rates, terms, and conditions of interconnection service for Small Generating Facilities are just and reasonable and not unduly discriminatory or preferential.[25] In particular, the Commission cited the growth in grid-connected solar photovoltaic (PV) generation since the issuance of Order No. 2006 and the growth in small generator interconnection requests driven by state renewable portfolio standards as the impetus for re-examining the *pro forma* SGIP.[26] The Commission reasoned that if generation penetration levels are causing projects to fail the 15 Percent Screen, the screen should be re-examined to determine if revisions could be made to allow projects to continue to participate in the less costly and time-consuming Fast Track Process while maintaining the safety and reliability of the Transmission Provider's system.[27] 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.[28]

B. Comments

16. Many commenters support the Commission's proposed reforms.[29] Commenters state that the recent rapid growth in small generators and expected significant growth in coming years, driven by public policies such as state renewable portfolio standards, requires revising the SGIP and SGIA.[30] For example, Public Interest Organizations[31] note that state solar initiatives are resulting in penetrations of distributed generation in excess of 15 percent on some line sections[32] and that the public policies driving the increase in Small Generating Facilities, together with lower prices for solar panels, smart grid enhancements and other factors, have ''given rise to barriers like lengthy interconnection queues and a lack of transparency about system conditions.''[33] Public Interest Organizations believe that these facts clearly demonstrate the need to reconsider the SGIP and to enact the proposed reforms to reduce the time and cost of processing the increasing volume of distributed generation projects.[34] IREC and SEIA similarly assert that reforming the SGIP and SGIA is essential to support the continued growth of the wholesale market for solar and other distributed resources.[35] Public Interest Organizations go on to state that:

> The increased volume of applications along with the higher penetration levels that will result from these policy changes necessitate updating SGIP to enable providers to continue processing applications efficiently and without imposing unnecessary financial or regulatory hurdles to [distributed generation] development. Since in some instances existing SGIP act as regulatory barriers to further reliable deployment of [distributed generation] resources, the SGIP have become unduly discriminatory and can no longer be assumed to be just and reasonable.[36]

17. CREA and ESA support the effort to reform the SGIP and assert that the current system results in delays and unnecessarily increases project costs. AWEA and ELCON[37] similarly state that the proposed reforms ensure that small generator interconnection requests are processed in a just and reasonable and not unduly discriminatory manner.[38]

18. International Transmission Company (ITC) supports streamlining the SGIP in ways that maintain safety and reliability.[39]

19. Independent System Operators (ISO) and Regional Transmission Organizations (RTO) generally support the NOPR objectives,[40] but request, in recognition of regional differences and existing ISO/RTO interconnection processes, that they be allowed to meet those objectives under either the independent entity variation standard[41] or the regional differences standard.[42] Similarly, the National Association of Regulatory Utility Commissioners (NARUC) supports the Commission's efforts to update the *pro forma* SGIP and SGIA, but requests flexibility in the revisions to account for regional differences.[43] NARUC also states that

---

[25] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 18.

[26] *Id.* P 20.

[27] *Id.* P 22.

[28] *Id.* P 23.

[29] *See, e.g.,* American Wind Energy Association (AWEA) at 2–3; Clean Coalition at 2; ClearEdge Power (CEP) at 1–2; ComRent International (ComRent) at 1; Community Renewable Energy Association (CREA) at 1–2; Office of the People's Counsel for the District of Columbia (DCOPC) at 1; Duke Energy Corporation (Duke Energy) at 1; ELCON at 3; Electricity Storage Association (ESA) at 3; Fuel Cell & Hydrogen Energy Association (FCHEA) at 1–2; Max Hensley at 1–2; Industrial Energy Consumers of America (IECA) at 4; IREC at 2; NRG at 2; Public Interest Organizations at 6–9; SEIA at 1; Union of Concerned Scientists (UCS) at 3, 8–9; and Lucia Villaran at 1–2.

[30] IREC at 3 (citing Solar Electric Power Association, 2012 SEPA Utility Solar Rankings Executive Summary 2 (2013)), *available at http://www.solarelectricpower.org/media/279520/sepa-top-10-executive-summary_final-v2.pdf*); AWEA at 3; DCOPC at 3–4; ELCON at 5; NRG at 2; Public Interest Organizations at 3–4, 6–9; and UCS at 9.

[31] The Center for Rural Affairs, Climate + Energy Project, Conservation Law Foundation, Energy Future Coalition, Environmental Defense Fund, Environmental Law & Policy Center, Environment Northeast, Fresh Energy, Great Plains Institute, National Audubon Society, Natural Resources Defense Council, Northwest Energy Coalition, Pace Energy and Climate Center, Piedmont Environmental Council, Sierra Club, Southern Alliance for Clean Energy, Southern Environmental Law Center, Sustainable FERC Project, Union of Concerned Scientists, Utah Clean Energy, Western Grid Group, Western Resource Advocates, The Wilderness Society and Wind on the Wires are referred to collectively as Public Interest Organizations in this Final Rule.

[32] Public Interest Organizations at 4–5.

[33] *Id.* at 1.

[34] *Id.* at 5–9.

[35] IREC at 4 and SEIA at 1.

[36] Public Interest Organizations at 5.

[37] The Electricity Consumers Resource Council, American Chemistry Council, American Forest & Paper Association, American Iron and Steel Institute, CHP Association and Council of Industrial Boiler Owners are collectively referred to as ELCON in this Final Rule.

[38] AWEA at 2 and ELCON at 3.

[39] ITC at 6.

[40] CAISO at 1, 9; IRC at 1; ISO–NE at 8, 15; MISO at 4–5; NYISO & NYTO at 2; and PJM at 1, 3–4.

[41] CAISO at 2 and 7 and NYISO & NYTO at 4, 24–25. The independent entity variation is a balanced approach that provides RTOs and ISOs greater flexibility to customize their interconnection procedures and agreements to accommodate regional needs. It recognizes that an RTO or ISO has differing operating characteristics depending on its size and location and is less likely to act in an unduly discriminatory manner than a Transmission Provider that is also a market participant. *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822–827.

[42] ISO–NE at 2, 5–7; PJM at 4; and IRC at 1, 3–6. A regional differences standard would allow variations based on regional differences resulting from regional interconnection standards or reliability requirements. For non-independent Transmission Providers, Order No. 2006 recognizes regional reliability variations based on established regional reliability requirements when supported by reference to established regional reliability requirements and including the text of the reliability requirement. *See* Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 546.

[43] NARUC at 10.

the reforms should not impinge on successful state interconnection procedures.[44]

20. NRECA, EEI & APPA believe that the *pro forma* SGIP and SGIA adopted in Order No. 2006 continue to be just and reasonable and strike a fair balance between the competing goals of uniformity and flexibility while ensuring safety and reliability.[45] NRECA, EEI & APPA further assert that the current record cannot support a finding that existing Order No. 2006 procedures are unjust, unreasonable or unduly preferential, nor can the record support a finding that the Commission's proposals are just and reasonable, not unduly preferential, or would not impair reliability or safety.[46] Specifically, NRECA, EEI & APPA contend that before modifications to the Fast Track Process are considered, there must be evidence to suggest that the 15 Percent Screen no longer serves to adequately reduce interconnection costs and time compared to the full Study Process. They further argue that there also must be evidence showing that higher penetrations of generation can be safely and reliably accommodated without the need for the Study Process.[47] They also believe, however, that the *pro forma* SGIP and SGIA can be revised to enable the growth of renewable energy while continuing to facilitate jurisdictional interconnections in a just and reasonable manner and to benefit consumers and other stakeholders.[48]

C. Commission Determination

21. The Commission is persuaded to adopt its proposed revisions to the *pro forma* SGIP and the *pro forma* SGIA, as modified herein.[49] Without these reforms, the continued growth in Small Generating Facilities could cause inefficient interconnection queue backlogs and require some Small Generating Facilities to undergo the more costly Study Process when they could be interconnected under the Fast Track Process safely and reliably. Costs resulting from such inefficiencies in the interconnection process would ultimately be borne by consumers. The record in this proceeding does not refute the nature of the changes now occurring and expected to continue.

22. For example, approximately 3,300 MW of grid-connected PV capacity were installed in the U.S. in 2012,[50] compared to 79 MW in 2005, the year Order No. 2006 was issued.[51] The cumulative capacity of U.S. distributed PV is projected to double from mid-2013 to the end of 2015.[52] Similarly, installed wind generation with a capacity of 20 MW or less has increased in the contiguous United States from 1,185 MW in 2005 to 2,961 MW in 2012.[53] The growth in Small Generating Facilities is leading to an increase in small generator interconnection requests. In the NOPR, the Commission cited Commission filings that referenced higher volumes of small generator interconnection requests.[54] In its comments, IREC cited an unprecedented level of small solar interconnections.[55]

23. As noted by some commenters [56] and as the Commission noted in the NOPR, state renewable portfolio standards are driving small generator interconnection requests.[57] As of March 2013, 29 states and the District of Columbia had renewable portfolio standards, and an additional eight states had renewable portfolio goals.[58] Some state renewable portfolio standards include increasing percentages of renewable energy resources over time, which will lead to increasing penetrations of these resources. Some states have also adopted goals and policies to promote distributed generation.[59] Commenters also attribute the increase in PV to a decline in capital costs.[60] Installed costs for distributed PV installations fell by approximately 12 percent from 2011 to 2012, and have fallen 33 percent since 2009.[61]

24. The needs of Small Generating Facility developers, however, must be balanced against the concerns of the Transmission Providers, and the Commission has taken these concerns into consideration in developing this Final Rule. For example, the Commission notes that this Final Rule does not modify the 15 Percent Screen or any of the existing Fast Track screens. Rather, the Commission modifies the optional supplemental review process following failure of any of the Fast Track screens to include three supplemental review screens. In regions of the country where penetration levels are not high enough to cause Interconnection Customers to fail the 15 Percent Screen, Transmission Providers will generally continue to evaluate the penetration level of generation based on the 15 Percent Screen. However, in regions of the country where the 15 Percent Screen is causing Interconnection Customers to fail the Fast Track screens, the revised supplemental review will offer an opportunity to continue to be evaluated under the Fast Track Process.

25. The Commission therefore finds that our actions in this Final Rule are consistent with the standards that the court set forth in *National Fuel* v. *FERC*[62] and therefore disagrees with EEI, NRECA, and APPA that the existing record does not support the finding that the current SGIP and SGIA are unjust, unreasonable and unduly discriminatory. In the terminology of *National Fuel,* we find that a theoretical threat exists and we show herein how this threat justifies the costs that this Final Rule would create.[63] We conclude that, in light of the increasing small generator interconnection requests referenced in Commission filings [64] and

[44] *Id.*

[45] NRECA, EEI & APPA at 9.

[46] Id. at 10.

[47] *Id.* at 11.

[48] *Id.* at 1, 10. Duquesne Light supports the comments submitted by NRECA, EEI & APPA. (Duquesne Light at 3.)

[49] The Commission concludes that the revisions to the *pro forma* SGIP and *pro forma* SGIA adopted herein were reasonably foreseeable based on the NOPR, the March 2013 workshop and the comments received on the NOPR.

[50] Sherwood, Larry, U.S. Solar Market Trends 2012 at 4, *available at http://www.irecusa.org/wp-content/uploads/2013/07/Solar-Report-Final-July-2013-1.pdf.*

[51] U.S. Solar Market Insight Report, 2012 Year in Review, Executive Summary Table 2.1, *available at http://www.seia.org/research-resources/us-solar-market-insight-2012-year-in-review.*

[52] *See* Lacey, Stephen, Chart: 2/3rds of Global Solar PV Has Been Installed in the Last 2.5 Years, *available at http://www.greentechmedia.com/articles/read/chart-2-3rds-of-global-solar-pv-has-been-connected-in-the-last-2.5-years.*

[53] SNL Financial, *Power Plant Summary* (2013).

[54] *See, e.g., Cal. Indep. Sys. Operator Corp.,* 133 FERC ¶ 61,223, at P 3 (2010) (stating that an increasing volume of small generator interconnection requests had created inefficiencies); *Pacific Gas & Elec. Co.,* 135 FERC ¶ 61,094, at P 4 (2011) (stating that increased small generator interconnection requests resulted in a backlog of 170 requests over three years); *PJM Interconnection, LLC,* 139 FERC ¶ 61,079, at P 12 (2012) (stating that smaller projects comprised 66 percent of recent queue volume).

[55] IREC at 3 (citing Becky Campbell & Mike Taylor, 2011 Solar Electric Power Association Utility Solar Rankings at 7 (May 2012)).

[56] Public Interest Organizations at 3–5; IREC at 2; UCS at 3; and DCOPC at 3.

[57] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 20.

[58] *See* Dep't of Energy, IREC & North Carolina Solar Center, Renewable Portfolio Standard Policies (2013), *available at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.*

[59] *See* Dep't of Energy, IREC & North Carolina Solar Center, Renewable Portfolio Standard Policies with Solar/Distributed Generation Provisions (2013), *available at http://www.dsireusa.org/documents/summarymaps/Solar_DG_RPS_map.pdf.*

[60] VSI at 1–2 and Public Interest Organizations at 1.

[61] Sherwood, Larry, U.S. Solar Market Trends 2012 at 2, *available at http://www.irecusa.org/wp-content/uploads/2013/07/Solar-Report-Final-July-2013-1.pdf.*

[62] 468 F.3d 831, 839–44 (D.C. Cir. 2006) (*National Fuel*).

[63] *Id.* at 844.

[64] *See, e.g., Cal. Indep. Sys. Operator Corp.,* 133 FERC ¶ 61,223, at P 3 (2010) (stating that an increasing volume of small generator

Continued

in this proceeding,[65] the state renewable portfolio standards driving these requests,[66] and the growth in solar PV installations,[67] the reforms adopted herein are necessary to correct operational practices that can unnecessarily limit, and increase the cost of,[68] Commission-jurisdictional interconnections under the SGIP and SGIA. The Commission believes that adopting the reforms in this Final Rule will reduce the time and cost to process small generator interconnection requests for Interconnection Customers and Transmission Providers alike.

26. Specifically, as discussed above, the Commission believes that the current SGIP and SGIA inhibit the continued growth in Small Generating Facilities and cause unnecessary costs to be passed on to consumers. We agree with commenters that assert that the proposed reforms are necessary to avoid delays and unnecessary project costs (*e.g.,* under the SGIP originally adopted in Order No. 2006, generators that could be interconnected safely and reliably under the Fast Track Process are required to undergo the more costly and time-consuming Study Process).[69] Hence, we conclude that such delays and increased project costs are likely without the reforms proposed herein and that this threat is significant enough to justify the reforms imposed by this Final Rule. The threat is not one that can be addressed adequately or efficiently through the adjudication of individual complaints.[70] The remedy we adopt is justified sufficiently by the theoretical threat identified herein and based on the comments received, the identified theoretical threat represents a reasonable prediction of future market conditions.[71]

27. As acknowledged in the NOPR, the need for implementation of the reforms may not be uniform across the country.[72] The reforms adopted in this Final Rule will likely have a greater impact on Transmission Providers in areas with a significant penetration of distributed resources and a larger number of small generator interconnection requests.[73]

The Commission believes that this Final Rule balances the needs of Small Generating Facilities and public utility Transmission Providers, while providing flexibility to different regions of the country. Moreover, to further accommodate regional differences and in response to the comments submitted by RTOs and ISOs, the Commission is allowing independent Transmission Providers to comply with this Final Rule under the independent entity variation standard or the regional differences standard, consistent with the approach adopted in Order No. 2006.[74] Finally, we affirm that it is not our intent in this Final Rule to interfere with state interconnection procedures and agreements in any way. Similar to our approach in Order No. 2006,[75] 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.

IV. Proposed Reforms

A. Pre-Application Report

1. Commission Proposal

28. According to the reforms included in the NOPR, Transmission Providers would be required to provide Interconnection Customers the option to request a pre-application report that would contain readily available information about system conditions at a Point of Interconnection in order to help that customer select the best site for its Small Generating Facility. The Commission proposed the pre-application report to promote transparency and efficiency in the interconnection process and to provide information to Interconnection Customers about system conditions at a particular Point of Interconnection.[76]

29. To the extent available, the proposed pre-application report would include the following items:

a. Total capacity and available capacity of the facilities that serve the Point of Interconnection;

b. Existing and queued generation at the facilities likely serving the Point of Interconnection;

c. Voltage of the facilities that serve the Point of Interconnection;

d. Circuit distance between the proposed Point of Interconnection and the substation likely to serve the Point of Interconnection (Substation);

e. Number and rating of protective devices and number and type of voltage regulating devices between the proposed Point of Interconnection and the Substation;

f. Number of phases available at the proposed Point of Interconnection;

g. Limiting conductor ratings from the proposed Point of Interconnection to the Substation;

h. Peak and minimum load data; and

i. Existing or known constraints associated with the Point of Interconnection.

30. The Commission proposed a non-refundable $300 fee for the pre-application report and required that the report be provided within 10 business days of the initial request.[77] The Commission proposed that the pre-application report would only include information already available to the Transmission Provider.[78] Additionally, the proposed revisions to the *pro forma* SGIP, which were attached to the NOPR, state that ''The pre-application report request does not obligate the Transmission Provider to conduct a

interconnection requests had created inefficiencies); *Pacific Gas & Elec. Co.,* 135 FERC ¶ 61,094, at P 4 (2011) (stating that increased small generator interconnection requests resulted in a backlog of 170 requests over three years); *PJM Interconnection, LLC,* 139 FERC ¶ 61,079, at P 12 (2012) (stating that smaller projects comprised 66 percent of recent queue volume).

[65] IREC at 3, citing Becky Campbell & Mike Taylor, 2011 Solar Electric Power Association Utility Solar Rankings at 7 (May 2012).

[66] As noted above, as of March 2013, 29 states and the District of Columbia had renewable portfolio standards, and an additional eight states had renewable portfolio goals. *See supra* P 0.

[67] As noted above, approximately 3,300 MW of grid-connected PV capacity were installed in the U.S. in 2012 compared to 79 MW in 2005. Further, the cumulative capacity of U.S. distributed PV is projected to double from mid-2013 to the end of 2015. *See supra* P 0.

[68] *E.g.,* some of the reforms adopted herein are intended to increase the number of Small Generating Facilities that may be interconnected under the Fast Track Process rather than the Study Process. The cost to be evaluated under the *pro forma* SGIP Fast Track Process (without supplemental review) is $500. Under the *pro forma* SGIP Study Process, the Interconnection Customer must pay a deposit not to exceed $1,000 toward the cost of the feasibility study with its interconnection request and pay the actual cost of any required studies (normally a feasibility study, a system impact study, and a facilities study).

[69] *See supra* P 0.

[70] Individual adjudications by their nature focus on discrete questions of a specific case. Rules setting forth general principles are necessary to ensure that adequate processes are in place.

[71] *See, e.g., Black Oak Energy, LLC* v. *FERC,* Nos. 08–1386, 11–1275, 12–1286, 2013 WL 3988709, at *8 (D.C. Cir. Aug. 6, 2013) (stating ''[W]e defer to reasonable and cogent explanations of predictable economic outcomes, even in the absence of retrospective data''); *Sacramento Mun. Util. Dist.* v. *FERC,* 616 F.3d 520, 542 (D.C. Cir. 2010); Louisiana *Pub. Serv. Comm'n* v. *FERC,* 551 F.3d 1042, 1045 (D.C. Cir. 2008); *Envtl. Action, Inc.* v. *FERC,* 939 F.2d 1057, 1064 (D.C. Cir. 1991) (stating, ''[I]t is within the scope of the agency's expertise to make . . . a prediction about the market it regulates, and a reasonable prediction deserves . . . deference notwithstanding that there might also be another reasonable view'').

[72] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 24.

[73] *Id.* at P 4.

[74] *See infra* section V.

[75] Order No. 2006, FERC Stats. & Regs. ¶ 31,380 at P 8.

[76] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 26.

[77] *Id.* at P 28 and proposed *pro forma* SGIP at section 1.2.2.

[78] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 27.

study or other analysis of the proposed generator in the event that data is not readily available.'' [79]

2. Need for a Pre-Application Report

a. Comments

31. Many commenters support the concept of a pre-application report.[80] The California Public Utilities Commission (CPUC) supports the pre-application report and states that it will increase transparency and efficiency, reduce costs, and provide necessary information to Interconnection Customers.[81] Other commenters assert that the pre-application report is critical for developers to determine the best Points of Interconnection because it will eliminate some of the uncertainties involved in the interconnection process and thus reduce developer costs and schedule delays.[82] FCHEA states that the pre-application report will alert a project developer to potential issues at a Point of Interconnection prior to making a significant financial commitment.[83]

32. A number of commenters state that the pre-application report will likely reduce the number of interconnection requests submitted to Transmission Providers because developers frequently submit multiple interconnection requests for a single project in an effort to determine the most advantageous Point of Interconnection.[84] Similarly, IREC and SEIA contend that a pre-application report would benefit Transmission Providers by reducing the volume of interconnection requests that are either non-viable or difficult to accommodate.[85] Finally, Sandia National Laboratories (Sandia) and SEIA state that the pre-application report will foster communication between developers and Transmission Providers and will improve the interconnection process.[86]

33. Several RTOs and ISOs,[87] however, contend that they already offer various opportunities for Interconnection Customers to ask questions and request information that is similar to the information in the pre-application report. These commenters state that information related to the type, amount and location of interconnected and pending projects and studies is readily available by phone, on their Web sites, or through their Critical Energy Infrastructure Information (CEII) process.[88] ISO New England (ISO–NE) asserts that there is no indication that the information it currently makes available to Interconnection Customers is insufficient.[89]

34. Midcontinent Independent System Operator (MISO) states that its existing procedures, including a pre-application meeting, may be more effective than the proposed pre-application report procedures.[90] MISO asserts that a pre-application meeting achieves the same goals of transparency and data sharing without the cost and inefficient expenditure of resources that a pre-application report would require.[91] MISO further asserts that requiring the Transmission Provider to contact the Transmission Owner to collect information may be inefficient and that permitting the Interconnection Customer to directly contact the Transmission Owner may be more efficient.[92]

35. The California Independent System Operator Corporation (CAISO) states that it supports the provision of a pre-application report, but in some cases the pre-application report information is only available from the participating Transmission Owner and in other cases it does not exist for networked transmission systems. CAISO requests that the Commission allow ISOs and RTOs to provide a pre-application report that is appropriate to interconnecting to a networked transmission system, such as existing and queued generation not at the same Point of Interconnection but affected by the same transmission constraints.[93]

36. San Diego Gas & Electric Company, Southern California Edison Company and Pacific Gas and Electric Company (California Utilities) state that larger interconnection projects should be required to obtain a pre-application report because it will increase the likelihood that these projects will select Points of Interconnection that qualify for Fast Track evaluation.[94]

b. Commission Determination

37. The Commission concludes that providing the Interconnection Customer with the opportunity to request the pre-application report will benefit the interconnection process by helping Interconnection Customers make more informed siting decisions and may diminish the practice of requesting multiple interconnection requests for a single project, which benefits both Transmission Providers and Interconnection Customers. As such, the Commission adopts its proposal to require the Transmission Provider to provide Interconnection Customers with the opportunity to request a pre-application report, as modified herein.

38. While the Commission appreciates that some Transmission Providers may already make available some of the information in the pre-application report, commenters suggest that this information may not be available from all Transmission Providers. Therefore, the Commission finds it just and reasonable to include the pre-application report in the *pro forma* SGIP.

39. With regard to MISO's assertion that requiring the Transmission Provider to contact the Transmission Owner to collect information may be less efficient than permitting the Interconnection Customer to directly contact the Transmission Owner, we note that the Transmission Provider is generally the point of contact for the Interconnection Customer that coordinates the various SGIP processes (e.g., interconnection requests and the studies in the section 3 Study Process). As such, the Transmission Provider is expected to coordinate with the Transmission Owner and the Interconnection Customer, so we are not persuaded that we should adopt SGIP language requiring the Interconnection Customer to contact the Transmission Owner directly in the case of the pre-application report.

40. Finally, with regard to MISO's comment that its existing pre-application procedures may be more effective than the pre-application report proposed in the NOPR, as discussed below, in cases where provisions in public utility Transmission Providers' existing interconnection procedures would be modified by the Final Rule, public utility Transmission Providers must either comply with the Final Rule or demonstrate that previously approved variations meet one of the standards for variance provided for in this Final Rule.[95]

[79] *Id.,* Appendix C, SGIP section 1.2.4.

[80] NREL at 2; Clean Coalition at 3; CPUC at 4; CREA at 2; DCOPC at 4; Duke Energy at 3; ELCON at 4; FCHEA at 1; IECA at 4; LES at 1; NRECA, EEI & APPA at 6; and NRG at 5.

[81] CPUC at 5.

[82] CEP at 1; CREA at 2; DCOPC at 4; Duke Energy at 3; IREC at 9; NRG at 4; and Public Interest Organizations at 9.

[83] FCHEA at 1.

[84] AWEA at 3–4; CREA at 2; IREC at 9; ITC at 8; and NRG at 5.

[85] IREC at 9 and SEIA at 10.

[86] Sandia at 2 and SEIA at 12.

[87] ISO–NE., MISO, PJM, and NYISO.

[88] ISO–NE at 8; MISO at 5–6; NYISO & NYTO at 13–14; and PJM at 5.

[89] ISO–NE at 8.

[90] MISO at 4 (referencing section 6.1 of MISO's Generator Interconnection Procedure).

[91] *Id.* at 5.

[92] *Id.* at 5–6.

[93] CAISO at 4.

[94] California Utilities at 4.

[95] *See infra* section V.

3. Pre-Application Report Fee

a. Comments

41. Several commenters support the proposed $300 fee for the pre-application report.[96] IREC asserts that the $300 fee is appropriate for the effort required to provide the report, noting that there is currently no fee for the provision of similar system information under section 1.2.1 of the SGIP.[97] NREL states that the proposed $300 fee only allows the Transmission Provider to provide information that is quickly accessible.[98]

42. Several commenters, including many Transmission Providers, recommend that the Commission set the cost of the pre-application report equal to the Transmission Provider's actual incurred cost rather than a fixed $300 fee.[99]

43. PJM Interconnection (PJM) estimates that the processing and preparation of a single report will take ten to twelve hours in administration, preparation, and final review and cost at least $1,500.[100] NRECA, EEI & APPA similarly state that, on average, the processing and preparation of a single report will likely require at least eight hours of an engineer's time, at a cost of $150 per hour, resulting in a minimum initial pre-application report fee of $1,200, not including time spent coordinating with the distribution utility to gather system information.[101] IREC, on the other hand, contends that the coordination between the Transmission Provider and the utility should not be overly burdensome for either party, and it is not significantly different from the coordination required during the SGIP Study Process.[102]

44. NRECA, EEI & APPA also request that the $300 fee be adjusted annually based on an inflation index, such as the Consumer Price or Handy-Whitman index, so that fees charged reflect the actual cost to prepare the pre-application report.[103] ITC proposes a ''deposit/not-to-exceed'' fee structure for the pre-application report whereby the Interconnection Customer submits a $300 deposit and designates a dollar amount that the Transmission Provider is not to exceed when preparing the report.[104] ITC proposes that the cost of the pre-application report be trued-up upon completion based on the Transmission Provider's actual incurred costs.[105]

b. Commission Determination

45. The Commission finds that a fixed pre-application report fee will both provide cost certainty to Interconnection Customers and result in lower administrative costs than other fee structures. The Commission notes that this approach is similar to Commission treatment of other fixed processing fees in Order No. 2006.[106] Thus, the Commission will not adopt NRECA, EEI & APPA's proposal to index the pre-application report fee because Transmission Providers will have the opportunity to propose revisions to the fixed pre-application report fee in the compliance filing and in any subsequent FPA section 205 filings.

46. While the Commission believes that the $300 fee often will be adequate to recover Transmission Providers' costs of preparing the pre-application report given that Transmission Providers are only asked to provide ''readily available'' information, the Commission finds it would be unjust and unreasonable for Transmission Providers not to recover their actual pre-application report preparation costs. Accordingly, the Commission will adopt the $300 fee as the default fee in the *pro forma* SGIP and give Transmission Providers the opportunity to propose a different fixed cost-based fee for preparing pre-application reports supported by a cost justification as part of the compliance filing required by this Final Rule. The Commission notes that the Transmission Provider already provides information to the Interconnection Customer under section 1.2 of the *pro forma* SGIP. Therefore the pre-application report fee should only include the cost of providing the incremental information required under this Final Rule.

4. Pre-Application Report Timeline

a. Comments

47. The Commission received multiple comments about the ten-business-day timeline for providing the proposed pre-application report. MISO and Public Interest Organizations support the proposed ten-business-day timeframe for the pre-application report.[107] SEIA contends that a predictable date certain for the pre-application report is crucial for developers.[108] SEIA finds the proposed timeline reasonable, but requests that if the Commission extends the timeline, it allow Transmission Providers to request a one-time ten-day extension if necessary.[109]

48. NRECA, EEI & APPA assert that SEIA's ten-day extension proposal would lead to inefficient use of Commission and utility resources, and that ten additional days would likely be insufficient in many circumstances.[110] Instead, NRECA, EEI & APPA request that the Commission clarify that section 4.1 of the current *pro forma* SGIP (''Reasonable Efforts'') provides the Transmission Provider with the option of promptly communicating to the Interconnection Customer the nature of any delays, including force majeure events,[111] in preparing a pre-application report and allows for both parties to agree on the Transmission Provider delivering the pre-application report on a different date.[112] NRECA, EEI & APPA state that this arrangement will give the developer some degree of certainty as to when it can expect to see a pre-application report, while allowing the utility reasonable flexibility given the realities of staffing and work load.[113] ISO–NE., PJM and the ISO/RTO Council (IRC) also ask the Commission to affirmatively state that section 4.1 of the SGIP applies to the pre-application report timeline.[114]

49. Duke Energy proposes that when a Transmission Provider has reached its maximum ability to process pre-application requests within the prescribed ten-business-day deadline, any subsequent requests received during that heavy volume period would be placed in a queue. Under Duke Energy's proposal, Interconnection Customers would be notified of the likely timing of the Transmission Provider's processing of their requests. Once the backlog of requests has been processed, the Transmission Provider would resume

[96] CPUC at 4; CREA at 2; IREC at 12; MISO at 3–4; NRG at 5; and Public Interest Organizations at 9.

[97] IREC at 12. Under section 1.2 of the *pro forma* SGIP, the Interconnection Customer may request from the Transmission Provider ''relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection'' at a specific proposed Point of Interconnection.

[98] NREL at 3.

[99] ISO–NE at 13–14; ITC at 7–8; NARUC at 5; NRECA, EEI & APPA at 16; and NREL at 3.

[100] PJM at 8.

[101] NRECA, EEI & APPA at 16.

[102] IREC at 12.

[103] NRECA, EEI & APPA at 16.

[104] ITC at 8.

[105] *Id.* at 8–9.

[106] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 126.

[107] MISO Comments at 3–4; Public Interest Organizations at 9.

[108] SEIA Reply Comments at 6.

[109] *Id.* at 7.

[110] NRECA, EEI & APPA Reply Comments at 13–14.

[111] NRECA, EEI & APPA at 18, Appendix C (requesting that the Commission include language in the SGIP to cover delays related to force majeure events).

[112] *Id.* at 18–19.

[113] *Id.* at 19.

[114] IRC at 9–10; ISO–NE at 12; and PJM at 10.

processing pre-application requests within the ten-business-day period.[115]

50. ISO–NE also requests that the Commission allow for additional time for providing the pre-application report.[116] New York Independent System Operator and New York Transmission Owners (NYISO & NYTO) and PJM recommend that the Commission extend the proposed time period for processing the pre-application report to 20 business days.[117] IRC also states that ten business days is not enough time to produce the pre-application report and therefore asks the Commission to provide each region with the flexibility to propose its own time frame.[118]

b. Commission Determination

51. The Commission is persuaded by Transmission Provider comments that certain circumstances could make the ten-business-day timeline difficult to meet. The Commission will therefore modify its proposal and extend the pre-application report due date from 10 to 20 business days, as proposed by NYISO & NYTO and PJM.[119] We find that this deadline balances Transmission Provider concerns about having adequate time to prepare the report with Interconnection Customer concerns regarding the importance of knowing when they will receive the report. As such, Transmission Providers will be required to provide the pre-application report within 20 business days of the initial request.

52. With regard to the request of ISO–NE., IRC, PJM, and NRECA, EEI & APPA for clarification about whether section 4.1 (''Reasonable Efforts'') of the existing *pro forma* SGIP will apply to the pre-application report timeline,[120] we affirm that section 4.1 of the *pro forma* SGIP applies to the pre-application report. To not do so would mean that the Reasonable Efforts section would apply to some items in the SGIP and not others. As such, the Commission declines to adopt Duke Energy's proposal to establish a pre-application queue when a Transmission Provider experiences heavy volumes of pre-application report requests and is unable to meet the pre-application report timeline because such situations may be addressed under section 4.1 of the *pro forma* SGIP in a comparable, not unduly discriminatory manner. Nonetheless, the Commission notes that the pre-application report contains only readily available information, so we expect that the Transmission Provider should be able to produce a pre-application report within 20 business days in most circumstances.

5. Pre-Application Report Request Form

a. Comments

53. Several commenters recommend that Interconnection Customers complete a pre-application report request form to facilitate report preparation.[121] ITC offers as a basis for such a form that Interconnection Customers could designate broad geographic areas as proposed Points of Interconnection when requesting a pre-application report, thus requiring the Transmission Provider to select the exact Point of Interconnection for the Interconnection Customer.[122]

54. Such a form is also supported by the SWG[123] and PJM.[124] They suggest that the proposed pre-application request form seeks the following information from Interconnection Customers: (1) Project contact information; (2) project location, including street address with nearby cross streets and town; (3) meter number, pole number, or other equivalent information identifying the proposed Point of Interconnection; (4) type of generator; (5) size of generator; (6) single or three-phase generator configuration; (7) whether the generator is stand-alone or serves on-site load; and (8) whether the project requires new service or is an expansion of existing service.[125]

55. ITC, IRC and NYISO & NYTO also support a standardized pre-application report request form.[126] IRC states that, although it supports including a standard request form in each Transmission Provider's tariff, the Final Rule should allow the request form to vary by region if needed.[127]

b. Commission Determination

56. In response to commenter requests, the Commission adopts the standardized pre-application report request form as proposed by the SWG in section 1.2.2 of the *pro forma* SGIP, as modified herein[128] and with certain minor clarifying modifications, to use when requesting a pre-application report. The Commission believes the request form will resolve uncertainty about the precise location of the Point of Interconnection and expedite the pre-application report process.

6. Readily Available Information

a. Comments

57. SEIA and DCOPC state that the proposed pre-application report will not burden Transmission Providers because it will be compiled from existing material.[129] IREC claims that utilities have made significant investments in smart grid infrastructure, SCADA and other methods of gathering system information so that minimum and peak load data will be available in the future, and the SGIP should encourage the collection of such information.[130] Sandia and UCS raise similar arguments about the availability of this data.[131]

58. Several commenters request that the Commission affirm that Transmission Providers are only required to provide existing information that is readily available in the pre-application report.[132] Additionally, multiple commenters request that the Commission define the terms ''already available'' and/or ''readily available'' as they relate to information provided in the pre-application report.[133] MISO suggests it means providing existing data in its existing form.[134] IRC further requests that the Commission clearly state in section 1.2.4 or add a new section 1.2.5 stating that ''[a]ny further analysis related to the proposed generator or in follow-up to the information contained in the report shall be conducted pursuant to an interconnection request.''[135]

59. ISO–NE and NYISO & NYTO state that notwithstanding the caveat in section 1.2.4, the pre-application report only need include existing data and note that the inclusion of all of the categories of data listed in section 1.2.3 of the *pro forma* SGIP could create an unreasonable expectation regarding the information to be included in the pre-

[115] Duke Energy at 4–5.

[116] ISO–NE at 12–13.

[117] NYISO & NYTO at 16; and PJM at 10.

[118] IRC at 9.

[119] NYISO & NYTO at 16; and PJM at 10.

[120] IRC at 10; ISO–NE at 12; NRECA, EEI & APPA Reply Comments at 14; and PJM at 10.

[121] IREC at 10; ISO–NE at 11; ITC at 10; NRECA, EEI and APPA at 13; NYISO & NYTO at 16; SEIA at 2; NREL at 2; and PJM at 9.

[122] ITC at 10.

[123] *See supra* note 23. The group drafted proposed revisions to the pre-application report proposal that were submitted by several commenters.

[124] IREC at 10 and PJM at 9.

[125] PJM at 9; IREC, Attachment A, §§ 1.2.2.1–1.2.2.8; NRECA, EEI & APPA, Attachment A, §§ 1.2.2.1–1.2.2.8; NREL, attachment to comments, §§ 1.2.2.1–1.2.2.8; and SEIA, Attachment B, §§ 1.2.2.1–1.2.2.8.

[126] ITC at 10; IRC at 9; NRECA, EEI & APPA at 13; and NYISO & NYTO at 16.

[127] IRC at 9.

[128] *See, e.g., supra* P 0.

[129] DCOPC at 4 and SEIA at 11.

[130] IREC at 10.

[131] Sandia at 2 and UCS at 14–15.

[132] Bonneville at 2–3; Duke Energy at 4; ISO–NE at 14; and MISO at 6.

[133] Clean Coalition at 3; Duke Energy at 4; IRC at 10; and MISO at 6.

[134] MISO at 6.

[135] IRC at 10–11.

application report.[136] ISO–NE and NYISO & NYTO therefore ask the Commission to clarify that the items proposed to be included in the pre-application report are examples that may be amended by the Transmission Provider based on readily available information.[137] IRC asks that the Commission allow each region to specify what information is actually available in a pre-application process to assist prospective Interconnection Customers.[138]

60. NREL comments that the proposed SGIP states that minimum daytime load information will be provided in the pre-application report ''when available'' and that this should be modified to state that load information ''will be measured or calculated.'' [139] FCHEA and CEP assert that one of the key pieces of information that should be included in the pre-application report is whether the 15 Percent Screen has been exceeded or is close to being exceeded on a particular line segment.[140] NRECA, EEI & APPA submitted proposed revisions to the information included in the pre-application report, including removing some items from the report.[141] IREC states that striking relevant pieces of information, such as minimum or peak load data, from the report because it may not be currently available would be inconsistent with policy goals and fails to recognize that grid investments may make the information possible to collect in the future.[142]

61. NRECA, EEI & APPA state that they are particularly concerned with the Commission's proposal to require that utilities provide minimum load and available capacity in the pre-application report when such data are not currently available.[143] They assert that collection of minimum load data is burdensome to most utilities because it is not a critical system operating criteria and is difficult to determine accurately.[144]

62. Duke Energy states that although daytime minimum load data may be available where there are electronic meters and communication equipment, in many instances the data are available only at the substation circuit breaker and not by line section. Duke Energy therefore asserts that in some cases it would have to estimate the minimum load.[145] ITC suggests that the Commission explain how Transmission Providers should calculate minimum load for the purposes of the pre-application report.[146]

b. Commission Determination

63. The Commission appreciates Transmission Provider concerns about the burden associated with creating new information (either form or substance) for the purposes of the pre-application report. We reaffirm that Transmission Providers are only required to provide the items in the *pro forma* SGIP section 1.2.3 if they are readily available, in accordance with section 1.2.4 of the SGIP. Accordingly, in response to NRECA, EEI & APPA and Duke Energy, the provision of actual or estimated minimum load data is not required unless it is readily available. To address concerns with the definition of ''readily available,'' we clarify that ''readily available'' means information that the Transmission Provider currently has on hand. That is, the Transmission Provider is not required to create new data.[147] However, the Transmission Provider is required to compile, gather, and summarize the information that it has readily available to it in a format that presents useful information.[148] The costs associated with that effort should be commensurate with the fee the Transmission Provider charges for the pre-application report. If providing some of the items in the pre-application report would require the Transmission Provider to undertake studies or analysis beyond gathering and presenting existing information, then the information is not readily available and the Transmission Provider is not obligated to include this information in the report. We note, however, that performing simple calculations with existing information, such as calculating available capacity as described below, falls within the meaning of readily available information.[149] The Commission finds that requiring Transmission Providers to provide information in pre-application reports beyond what is readily available would increase Transmission Provider costs and likely result in the under-recovery of report preparation costs. The Commission believes the default $300 fixed fee is consistent with the readily available standard, which limits the effort required by Transmission Providers.

64. The Commission is also persuaded by IREC's comments that pre-application report items should not be struck from the report due to current unavailability because the items may become available in the future. Thus, the Commission finds that the default pre-application report should include the items listed from section 1.2.3 of the proposed SGIP while at the same time reaffirming that Transmission Providers are not obligated to provide information that is not readily available.

7. Other Issues

a. Comments

65. IREC, Pepco [150] and SEIA propose adding a new section 1.2.3.1 to the *pro forma* SGIP stating that the Transmission Provider will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection and clarifying how the Transmission Provider will select which circuit to include as the Point of Interconnection in the pre-application report if there is more than one circuit to which the Interconnection Customer could connect.[151] The commenters also propose to clarify in section 1.2.3.1 that the Transmission Provider will not be liable if the selected circuit is not the most cost-effective option and explains that customers who want information on all options must request multiple pre-application reports.[152]

66. Several commenters,[153] including the SWG, note that the electric system is constantly changing and the information provided in the pre-application report might quickly become out of date. As a result, they request that the SGIP and each pre-application report that a utility

[136] ISO–NE at 9 and NYISO & NYTO at 15.

[137] NYISO & NYTO at 14.

[138] IRC at 10.

[139] NREL at 3.

[140] CEP at 2 and FCHEA at 2.

[141] NRECA, EEI & APPA, Appendix B at 1–2.

[142] IREC at 9–10.

[143] NRECA, EEI & APPA at 14.

[144] *Id.* at 14.

[145] Duke Energy at 5.

[146] ITC at 9–10.

[147] The Commission declines to prescribe a methodology for calculating minimum load for the purpose of the pre-application report, as requested by ITC, because such a calculation is not required for the sole purpose of the pre-application report. The provision of minimum load data in the pre-application report, whether actual or estimated, is only required if this information is readily available. Further, to the extent such a calculation is made under section 2.4.4.1 of the SGIP adopted herein, the Commission leaves the methodology to the discretion of the Transmission Provider.

[148] *See supra* P 0. The Commission clarifies that the Transmission Provider shall be the point of contact for the Interconnection Customer and may be required to coordinate with the Transmission Owner to execute the requirements of the SGIP adopted herein, including the pre-application report. Accordingly, we find that information that is readily available to the Transmission Owner shall be deemed readily available to the Transmission Provider as well.

[149] *See infra* P 0.

[150] Pepco Holdings Inc., Atlantic City Electric Company, Delmarva Power & Light Company, and Potomac Electric Power Company are referred to collectively as Pepco in this Final Rule.

[151] IREC at 10; Pepco, Appendix to comment at section 1.2.3.1; SEIA at Attachment A section 1.2.3.1.

[152] IREC at 10–11; Pepco at 6.

[153] Duke Energy at 6; IREC Attachment A, section 1.2.2 presenting the SWG recommendations; and NRECA, EEI & APPA at 12.

produces include a disclaimer indicating that the pre-application report is for informational purposes, is non-binding, and does not convey any rights in the interconnection process.[154]

67. ITC argues that given its dynamic nature, Transmission Providers may not be able to accurately predict the available capacity of the substation/area bus or bank circuit most likely to serve the proposed Point of Interconnection at every point in time.[155] ITC proposes that the Commission specify that the Transmission Provider's base-case estimate of available capacity is sufficient for the pre-application report.[156] Duke Energy states that Interconnection Customers can calculate this available capacity from the information provided in sections 1.2.3.1 through 1.2.3.3 of the SGIP; therefore, the Transmission Provider should not be required to provide available capacity in the pre-application report.[157]

68. Various commenters request that the pre-application report contain information that the Commission did not include in the NOPR. For example, several commenters propose to add the following items to the pre-application report: (1) Distance from a three-phase circuit if the Point of Interconnection is on a single-phase circuit; and (2) whether the Point of Interconnection is located on an area network, spot network, grid network, or radial supply.[158] IREC asserts that this approach will provide relevant system information to developers.[159] SEIA also proposes to include the substation/area bus, bank or circuit most likely to serve the Point of Interconnection.[160] NARUC states that the pre-application report should include a simple ''yes'' or ''no'' question as to whether minimum load data would be readily available should it be needed to help a developer remain in the Fast Track Process.[161]

69. Landfill Energy Systems (LES) state that the pre-application report should identify the type of existing relays that are currently being utilized and any known, or likely, need to replace those relays.[162] LES states that if, for example, the Transmission Owner is likely to require the Interconnection Customer to replace and/or upgrade existing equipment, such as a relay system, a reclosing system, or a breaker failure protection system, or to install fiber optic cable, it should be noted in the pre-application report.[163] LES also requests that the pre-application report include a map that shows the Transmission Provider's lines in the area for the Interconnection Customer to consider as alternative Points of Interconnection.[164]

70. Clean Coalition recommends that the Commission require that Transmission Providers maintain information about all distribution interconnection applications in a public spreadsheet/database for easy review and tracking by developers, advocates, and policymakers.[165] Clean Coalition further asserts that, where warranted by demand, existing grid information should be made available in map and spreadsheet formats on the utility's Web site.[166] NRECA, EEI & APPA claim that the Clean Coalition's proposal is unduly burdensome, overbroad, ambiguous, may result in the release of CEII, and would constitute jurisdictional overreach by the Commission.[167]

71. NRECA, EEI & APPA state that any information that is required to be included in the pre-application report must be consistent with existing safeguards against the public disclosure of non-public transmission system information, confidential information, or CEII.[168] CAISO similarly notes that some of the information may be proprietary to participating Transmission Owners or might be CEII, which could require a non-disclosure and limited use agreement.[169]

72. PJM asks the Commission to clarify that although there may be some limited follow-up on the pre-application report (e.g., questions about the report from the Interconnection Customer), more detailed inquiries would need to be addressed through the submission of an interconnection request by the Interconnection Customer.[170] Duke Energy requests that the Commission clarify that any transmission information provided in the report would not be required to be posted on the OASIS.[171] NRECA, EEI & APPA state that each request related to a particular Point of Interconnection should be treated as a request for a separate pre-application report and the Transmission Provider must be able to collect a fee for each report it prepares.[172] NRECA, EEI & APPA assert that this is appropriate because requests for multiple interconnection points may require companies to gather information from various sources for each Point of Interconnection.[173] IREC and Pepco also propose SGIP language which states that customers who want information on multiple circuits at a single Point of Interconnection must request a separate pre-application report for each circuit.[174]

73. CAISO suggests that the Commission may want to provide greater flexibility for Transmission Providers to fashion a pre-application process to exchange information with developers following issuance of a pre-application report if developers have any follow-up questions.[175] NYISO & NYTO suggest that Transmission Providers might provide the Interconnection Customer the option of a follow-up meeting to discuss the pre-application report.[176] Finally, ISO–NE proposes to refer to entities that request pre-application reports as ''potential Interconnection Customers'' rather than ''Interconnection Customers'' in section 1.2 of the SGIP, which outlines the pre-application report.[177]

b. Commission Determination

74. The Commission agrees with commenters that the information provided in pre-application reports should be for informational purposes only given the dynamic nature of system conditions. Accordingly, the Commission will include a disclaimer in the *pro forma* SGIP and pre-application report stating that the information provided in the pre-application report is non-binding and that the Transmission Provider will not be held liable if information in the report is no longer accurate. The Commission notes that similar pre-application report disclaimers are proposed in SGIP proceedings in Ohio and Massachusetts.[178]

[154] NRECA, EEI & APPA at 12–13, and NYISO & NYTO at 16.

[155] ITC at 9.

[156] *Id.* at 9.

[157] Duke Energy at 6.

[158] IREC at 11–12; NRECA, EEI & APPA Appendix B at 1; Pepco at 11; and SEIA at 11.

[159] IREC at 11.

[160] SEIA at 11.

[161] NARUC at 5.

[162] LES at 2.

[163] *Id.* at 2–3.

[164] *Id.* at 3.

[165] Clean Coalition at 5–6.

[166] *Id.* at 6.

[167] NRECA, EEI & APPA Reply Comments at 15–16.

[168] NRECA, EEI & APPA at 14.

[169] CAISO at 4.

[170] PJM at 10.

[171] Duke Energy at 6.

[172] NRECA, EEI & APPA at 17.

[173] *Id.*

[174] IREC at 10–11; Pepco at 6.

[175] CAISO at 4.

[176] NYISO & NYTO at 16.

[177] ISO–NE at 10.

[178] Pub. Utilis. Comm'n of Ohio, *In the Matter of the Comm'n's Review of Chapter 4901:1–22, Ohio Admin. Code, Regarding Interconnection Servs.,* Case No. 12–2051–EL–ORD, at 7 (2013), *available at http://www.seia.org/sites/default/files/Ohio-Supplemental-Entry.pdf;* Mass. Dep't of Pub. Utils., *Order on the Distributed Generation Working Group's Redlined Tariff and Non-Tariff Recommendations,* Docket No. D.P.U. 11–75–E, at 14 (2013).

75. NRECA, EEI & APPA, Pepco, SEIA, and IREC propose adding the following two items to the pre-application report: (1) For single-phase circuits, the distance of the Point of Interconnection from the three-phase circuit; and (2) whether the Point of Interconnection is located on an area network, spot network, grid network, or radial supply.[179] The Commission is persuaded that this additional information will be useful to assess whether a project will qualify for the Fast Track Process at a given Point of Interconnection. Furthermore, the information should be readily available to Transmission Providers because it relates to basic system configuration. Accordingly, sections 1.2.3.10 and 1.2.3.12 of the SGIP are revised to include these items.

76. In order to clarify Interconnection Customer expectations with respect to the pre-application report, the Commission adopts IREC, SEIA and Pepco's proposed disclaimer that the bank or circuit selected by the Transmission Provider in the pre-application report does not necessarily indicate the circuit to which the Interconnection Customer may ultimately connect. The disclaimer is added to section 1.2.3 of the SGIP. However, the Commission declines to adopt IREC, SEIA and Pepco's request to clarify how the Transmission Provider will select which circuit to include in the pre-application report if there is more than one circuit to which the Interconnection Customer could interconnect because methodologies for selecting a circuit may be differ depending on the circumstances of the proposed interconnection and may differ among Transmission Providers. If Transmission Providers wish to provide this information to Interconnection Customers, they may do so in business practices.

[179] *See supra* note 158.

77. In response to Duke Energy's inquiry, the Commission affirms that information Transmission Providers provide in the pre-application will have no bearing on OASIS reporting requirements. The Commission also affirms that the pre-application report only applies to a single Point of Interconnection and that Interconnection Customers must submit payment and separate pre-application request forms if they are requesting information about multiple Points of Interconnection, including multiple circuits at a single Point of Interconnection. The Commission also finds that it would be unjust and unreasonable to expect the Transmission Provider to bear the cost of any follow-up studies resulting from the pre-application report. Therefore, apart from reasonable clarification of items in the pre-application report, the Transmission Provider is not required as part of this Final Rule to conduct any studies or analysis after furnishing the pre-application report unless the Interconnection Customer proceeds with a formal interconnection request.

78. The Commission expects Transmission Providers to continue to abide by the recommendations outlined in section 1.1.5 of the *pro forma* SGIP and with section 1.2.1 of the *pro forma* SGIP, which states that information may be provided ''to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements'' and that ''[t]he Transmission Provider shall comply with reasonable requests for such information.''

79. The Commission rejects ISO–NE's request to refer to entities requesting pre-application reports as ''potential Interconnection Customers'' within the *pro forma* SGIP because we are not aware that use of the term ''Interconnection Customer'' in the pre-application section 1.2 of the *pro forma* SGIP adopted under Order No. 2006 caused confusion or set incorrect expectations for Interconnection Customers or Transmission Providers.

80. The Commission rejects LES's request that Transmission Providers indicate what upgrades, if any, will be required at a Point of Interconnection when preparing a pre-application report for that Point of Interconnection. This information may not be readily available to a Transmission Provider.

81. The Commission is not persuaded by Duke Energy's assertion that it is unreasonable to ask Transmission Providers to provide available capacity, or an estimate of available capacity. Providing available capacity will not burden the Transmission Provider because doing so only requires Transmission Providers to subtract aggregate existing and queued capacity from total capacity, and will provide additional clarity to the interconnection customer.

82. The Commission finds Clean Coalition and LES's proposal to make certain small generator interconnection data publicly available as beyond the scope of the NOPR. However, we encourage Transmission Providers to look for ways to streamline the provision of and make transparent relevant public information in order to facilitate small generator interconnections.

B. Threshold for Participation in the Fast Track Process

1. Commission Proposal

83. In the NOPR, the Commission proposed to revise the 2 MW threshold for participation in the Fast Track Process to be based instead on individual system and generator characteristics up to a limit of 5 MW, as shown in Table 1 below.

Table 1: Fast Track eligibility as proposed in the NOPR.[180]

Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on ≥ 600 Ampere Line and ≤ 2.5 Miles from Substation
< 5 kilovolt (kV)	≤ 1 MW	≤ 2 MW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV	≤ 4 MW	≤ 5 MW

2. Comments

84. Many commenters support increasing the Fast Track threshold from 2 MW to 5 MW.[181] IREC states that the purpose of eligibility limits to the Fast Track Process should be to filter out projects that are highly unlikely to pass the Fast Track screens in order to save time and set clear customer expectations. However, IREC states that the eligibility limits do not need to duplicate or go beyond the Fast Track screens themselves.[182]

85. DCOPC states that it has no objections to the new Fast Track eligibility table proposed for section 2.1 of the SGIP or to raising the maximum eligibility size from 2 MW to 5 MW, as long as this change does not compromise system safety and grid reliability.[183]

86. Sandia supports the new Fast Track eligibility proposal in the NOPR, as it more accurately differentiates interconnection requests that do not cause impacts from those that could need further study and states that the characteristics in the proposal for Fast Track eligibility are technically reasonable.[184]

87. Clean Coalition states that it prefers no Fast Track eligibility threshold because the Fast Track screens themselves eliminate projects that are not appropriate for the Fast Track Process.[185] However, Clean Coalition states that because of utility concerns about eliminating the threshold, it supports the Commission's proposal for increasing the threshold.[186]

88. Max Hensley states that the Commission should allow facilities of up to 10 MW to qualify for the Fast Track Process. Mr. Hensley believes this would increase the market for distributed solar power generation and lower prices for residential customers.[187]

89. ITC generally supports increasing the upper bound of the Fast Track proposal based on line voltage, line amperage and proximity to the substation but is concerned that Interconnection Customers will abuse the 5 MW limit by submitting multiple interconnection requests for the same project in an effort to circumvent the Study Process, to the detriment of system reliability (e.g., a 20 MW wind farm comprised of five 4–MW wind turbines might submit five separate interconnection requests rather than a single 20 MW interconnection request). ITC recommends that the Commission allow individual ISOs or RTOs to coordinate Fast Track interconnections through their existing interconnection queue process to ensure Interconnection Customers are not able to circumvent the required studies necessary to protect safety and reliability.[188]

90. ISO–NE requests that the Final Rule allow flexibility to account for eligibility limits that may be unique to the region. For example, ISO–NE states that eligibility for the Fast Track Process in New England is limited to interconnections to distribution facilities and does not apply to facilities rated 69 kV or higher that are used for regional transmission service.[189]

91. NYISO & NYTO do not believe the Commission's proposed expansion of the Fast Track eligibility to 5 MW and the introduction of minimum load and other screens for the supplemental review process are likely to improve the time and cost to process the interconnection requests of small facilities in New York at this time.[190] NYISO & NYTO state that most of the very small generating facilities in New York seek to interconnect to distribution facilities that are not subject to the Commission's jurisdiction and are generally able to skip most, if not all, of the time and expense of the full study process due to their limited system impacts.[191]

92. Duke Energy states that the proposed values in the Fast Track threshold table are not realistic for distribution systems. Duke Energy asserts that, based on its experience, a 1 MW generator proposing to interconnect to its distribution facilities

[180] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 30.

[181] AWEA at 4; CREA at 2; IECA at 4–5; NRG at 5; SEIA at 13–14; Clean Coalition at 7; CEP at 1; ELCON at 4–5; ESA at 3–4; FCHEA at 1; IECA at 4–5; IREC at 13; LES at 2; Sandia at 2; and Public Interest Organizations at 10.

[182] IREC at 13.

[183] DCOPC at 5.

[184] Sandia at 2.

[185] Clean Coalition at 7.

[186] *Id.*

[187] Max Hensley at 1.

[188] ITC at 11.

[189] ISO–NE at 15.

[190] NYISO & NYTO at 16.

[191] *Id.* at 16–17.

under 5 kV, which are lightly loaded and have small conductor sizes, would not pass the Fast Track screens because it would likely exceed the minimum load of the line section and might exceed the rating of the conductor.[192] Duke Energy therefore urges the Commission to consider lowering the proposed threshold levels to values that are more realistic for a distribution system.[193]

93. NRECA, EEI & APPA support basing Fast Track eligibility on individual system and generator characteristics.[194] They state that it is difficult to use the size of the generator as a threshold to determine whether the Small Generating Facility should go through the Fast Track Process and that the location of the point of common coupling and the interconnecting feeder and loading characteristics should be major factors for determining Fast Track eligibility.[195]

94. NRECA, EEI & APPA assert that there is no standard definition of distribution system voltages in the United States and that there needs to be an upper bound voltage class limit that captures voltages of up to 69 kV. They state that the Commission should continue to follow its own precedent of taking into account the differences in utilities' distribution systems by building a degree of flexibility into the Final Rule with respect to the criteria for determining Fast Track eligibility.[196]

95. NRECA, EEI & APPA note that in Massachusetts and Rhode Island, the Fast Track Process does not include a 2 MW limit, but instead inverter-based equipment that has been ''listed'' using the UL1741 testing procedure is eligible for an expedited process.[197] They state that multiple inverter projects may or may not be considered ''listed'' in the proposed configuration, which means that some projects may not be eligible for the Fast Track Process.[198] According to NRECA, EEI & APPA, on a regional level, the capacity of solar projects that tend to pass the screen tests is typically in the 2 MW range. They therefore urge the Commission to keep this factor in mind when considering raising the limit to 5 MW.[199]

96. NRECA, EEI & APPA state that they are concerned that the third column of the Fast Track eligibility table in the NOPR, which refers to the location of a distributed generation facility on the feeder system relative to the distance from the source substation, would raise expectations from developers that they may be eligible for the Fast Track Process when they may not be.[200] The SWG agreed on proposed revised language to be inserted in section 2.1 of the SGIP to clarify the intent of the Fast Track eligibility limits and to address concerns regarding the role of the eligibility limits in setting customer expectations.[201]

97. Several commenters[202] submitted the table for Fast Track eligibility proposed by the SWG as shown in Table 2 below. The SWG proposes revising the Fast Track eligibility threshold applicable to inverter-based generators. The SWG also proposes the following changes to Fast Track Process eligibility: (1) Making all projects interconnecting to lines greater than 69-kV ineligible for the Fast Track Process (inverter-based projects interconnecting to lines up to and including 69 kV would be eligible for the Fast Track Process based on Table 2 below); (2) maintaining the current 2 MW limit for Fast Track eligibility for synchronous and induction machines (as opposed to inverter-based generators); (3) for lines below 5 kV, changing the Fast Track eligibility regardless of location to 500 kW for inverter-based projects; and (4) in the third column of the table, replacing ''≥ 600 Ampere Line'' with ''a Mainline'' and a footnote defining ''Mainline.''[203] [204] [205]

TABLE 2—FAST TRACK ELIGIBILITY FOR LISTED INVERTER-BASED SYSTEMS AS PROPOSED BY NRECA, EEI & APPA

Line voltage	Fast Track eligibility regardless of location	Fast Track eligibility on a mainline* and ≤2.5 miles** from substation
<5 kilovolt (kV)	≤500 kW	≤500 kW
≥5 kV and <15 kV	≤2 MW	≤3 MW
≥15 kV and <30 kV	≤3 MW	≤4 MW
≥30 kV and <70 kV	≤4 MW	≤5 MW

* For purposes of this table, a mainline will typically constitute lines with wire sizes of 4/0 AWG, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

** Electrical Circuit Miles.

*** An Interconnection Customer can determine this information in advanced [sic] by requesting a Pre-Application Report pursuant to section 1.2 [of the SGIP].

98. IREC believes the proposed revisions to the Fast Track eligibility table agreed to by the SWG are reasonable and reflect a technically justified approach to Fast Track eligibility. It recommends that the Commission adopt the proposed revisions.[206] Further, IREC states that some projects connecting to lines greater than 69 kV should go through the Study Process because the cost of interconnecting to larger lines is likely to be significant enough that generators may benefit from a more thorough cost estimate.[207] Regarding the 2 MW Fast Track eligibility limit for synchronous, induction machines, IREC notes that there are important technical differences between these generators and inverter-based systems that may require further consideration, so the SWG agreed that the Commission should maintain the current limit for these generators.[208] Finally, IREC states that although it believes that the MW limits proposed by the Commission in the NOPR are sufficiently conservative, it supports the

[192] Duke Energy at 7.

[193] *Id.* at 9–10. *See* Duke Energy at 9 for its proposed Fast Track eligibility table.

[194] NRECA, EEI & APPA at 19.

[195] *Id.* at 19–20.

[196] *Id.* at 20.

[197] *Id.*

[198] *Id.* at 20–21.

[199] *Id.* at 21.

[200] *Id.*

[201] IREC at 14.

[202] NRECA, EEI & APPA Appendix A; IREC Attachment A; NREL Attachment; and SEIA Attachment B. The Commission notes that there were minor differences among the tables submitted by NRECA, EEI & APPA, IREC, SEIA and NREL.

[203] IREC at 14–15.

[204] NRECA, EEI & APPA, Appendix A.

[205] AWG is American wire gauge, a standardized system used for the diameters of round conducting wires to help determine its current-carrying capacity and electrical resistance.

[206] IREC at 14.

[207] *Id.* at 15.

[208] *Id.*

SWG proposal because it provides comfort to utilities interconnecting generators on lines below 5 kV.[209]

99. While SEIA would prefer to eliminate the threshold for participation in the Fast Track Process, it views the Commission's proposal as a reasonable and appropriate balance between a developer's need for an efficient interconnection process and the safety and reliability concerns raised with respect to broadening the Fast Track screens.[210] SEIA supports the agreement reached by the SWG on revisions to the Commission's proposal, which primarily narrows the scope of projects that would be eligible for the Fast Track Process at either end of the voltage spectrum, while maintaining Fast Track eligibility for the vast majority of distributed solar projects.[211] SEIA believes the Commission's proposal as modified by the SWG represents a reasonable compromise between developers and Transmission Providers and therefore recommends that the Commission adopt the SWG's proposal on Fast Track Process eligibility.[212] Public Interest Organizations and NREL also support the SWG's proposed changes to Fast Track eligibility.[213]

100. NYISO & NYTO support the SWG's revised Fast Track eligibility table, but state that the upper voltage limit for a very small generating facility's eligibility in the Fast Track Process should be limited to 50 kV.[214] They note that the system modifications and costs associated with a Small Generating Facility interconnecting to 69 kV facilities in New York will require careful evaluation to ensure safety and reliability and should therefore remain within the Study Process.[215]

101. AWEA opposes limiting Fast Track eligibility to 2 MW for synchronous and induction machines. AWEA states that it understands the reason for this limit is due to concerns about the fault current contribution of different types of wind turbine generators. It states that these concerns are unfounded and that wind turbines up to 5 MW should be allowed to participate in the Fast Track Process. Alternatively, AWEA states that screens that identify the type of wind turbine and the fault current contribution of that type could be used to allow wind turbines to participate in the Fast Track Process up to 5 MW.[216]

3. Commission Determination

102. The Commission concludes that it is just and reasonable to adopt the Fast Track eligibility thresholds proposed by the SWG, with modifications as discussed below.

103. The Commission agrees with the following reforms proposed by the SWG: (1) Modifying Fast Track eligibility for inverter-based machines to be based on individual system and generator characteristics; (2) for lines below 5 kV, limiting Fast Track eligibility to generators less than 500 kW for a conductor less than 5 kV regardless of location; and (3) making all projects interconnecting to lines greater than 69-kV ineligible for the Fast Track Process. The Commission finds that the modifications to Fast Track eligibility proposed by the SWG, reflected in Table 3 below, are just and reasonable and strike a balance between allowing larger projects to use the Fast Track Process while ensuring safety and reliability.

TABLE 3—FAST TRACK ELIGIBILITY FOR INVERTER-BASED SYSTEMS, AS ADOPTED IN THIS FINAL RULE

Line voltage	Fast Track eligibility regardless of location	Fast Track eligibility on a mainline [1] and ≤2.5 electrical circuit miles from substation [2]
<5 kilovolt (kV)	≤500 kW	≤500 kW
≥5 kV and <15 kV	≤2 MW	≤3 MW
≥15 kV and <30 kV	≤3 MW	≤4 MW
≥30 kV and ≤69 kV	≤4 MW	≤5 MW

[1] For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[2] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to section 1.2 of the SGIP.

104. The SWG's proposed Fast Track eligibility table indicates that it is applicable to ''listed'' (see Table 2 above) inverter-based systems. However, section 2.1 of the SGIP states that a Small Generating Facility must meet the ''codes, standards, and certification requirements of Attachments 3 and 4'' of the SGIP, ''or the Transmission Provider has to have reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.'' In order to eliminate potential confusion regarding the applicability of the Fast Track Process and to eliminate potential conflicts between the language of section 2.1 of the SGIP and the Fast Track eligibility table (Table 3 above), the Commission does not adopt the references to listing or certification in the title of the table submitted by the SWG. In doing so, the text of the Fast Track eligibility table will be consistent with section 2.1, which allows that Small Generating Facilities either be certified *or* have been reviewed or tested by the Transmission Provider and determined to be safe to operate. We also note that in section 2.1 of the SGIP, we only refer to ''certified inverter-based systems'' rather than ''listed or certified inverter-based systems'' as proposed by the SWG because listing is a type of certification under Attachments 3 and 4 of the SGIP.

105. The Commission acknowledges comments stating that voltages below 5 kV are being phased out. Nonetheless, such facilities can still be found in parts of the country and, therefore, our reforms must address reliability concerns with this voltage class. We conclude that imposing lower limits on lower voltage lines is reasonable. As Duke Energy notes in its comments, a request to interconnect to distribution facilities under 5 kV, which are typically lightly loaded and have small conductor sizes, would likely exceed the minimum load of the line section and the conductor rating.

106. The Commission will maintain the 2 MW Fast Track threshold for

[209] *Id.*

[210] SEIA at 13–14.

[211] *Id.* at 14.

[212] *Id.*

[213] NREL at 3 and Public Interest Organizations at 10–11.

[214] NYISO & NYTO at 17.

[215] *Id.*

[216] AWEA Supplemental Comments at 3–5.

synchronous and induction machines as suggested by the SWG because there are important technical differences between these generators and inverter-based generators. The Commission notes that, in general, the technical characteristics of synchronous and induction machines, such as higher fault current capabilities, may require further study to ensure the safety and reliability of the interconnection.[217] Therefore, we agree that synchronous and induction machines should continue to be subject to the 2 MW Fast Track threshold.[218] We are not persuaded by AWEA that the safety and reliability concerns of the SWG associated with synchronous and induction machines are unfounded and therefore decline at this time to include these machines in Fast Track eligibility beyond the existing 2 MW threshold. Further, in response to AWEA's proposal to modify the Fast Track Process to include screens based on the type of wind turbine and the fault current contribution of that type to allow wind turbines to participate in the Fast Track Process up to 5 MW, we find that AWEA's proposal has not been developed and vetted in this rulemaking process, therefore we decline to adopt the proposal.[219] We note, however, that in accordance with section 2.1 of the SGIP, synchronous and induction machines up to 5 MW that are interconnected to the Transmission Provider's system through a certified inverter or that have been reviewed or tested by the Transmission Provider and determined to be safe to operate may be interconnected under the Fast Track Process in accordance with Table 3 above.

107. The Commission adopts the SWG proposal to limit Fast Track eligibility to those projects connecting to lines at 69 kV and below. The Commission is persuaded by commenters [220] that even though not all Small Generating Facilities interconnecting to lines above 69 kV would require study, some of them will, and the Commission agrees that the costs and system modifications of interconnecting to lines larger than 69 kV are likely significant enough that generators may benefit from the more thorough estimate developed through the Study Process.

108. Regarding ITC's concerns, the Commission believes that the potential for Interconnection Customers to submit multiple interconnection requests for the same project in an effort to circumvent the Study Process is limited because the Fast Track screens consider the aggregate generation on a line section.

109. The Commission acknowledges NYISO & NYTO's comment that certain facilities in New York may require a detailed study to ensure safety and reliability. However, the Fast Track Process itself will identify such facilities so they need not be eliminated from Fast Track eligibility.

110. Finally, to address NRECA, EEI & APPA's concern that the third column of the Fast Track eligibility table in the NOPR could raise Interconnection Customer expectations regarding eligibility for the Fast Track Process, the Commission adopts language in section 2.1 of the *pro forma* SGIP reminding small generators that Fast Track eligibility is distinct from the Fast Track Process itself, and that being found eligible for the Fast Track Process does not imply or indicate that a project will pass the Fast Track or supplemental review screens.[221]

C. Fast Track Customer Options Meeting and Supplemental Review

1. Commission Proposal

111. In the NOPR, the Commission proposed modifications to the customer options meeting following the failure of any of the Fast Track screens. The Commission proposed to require the Transmission Provider to offer to perform a supplemental review of the proposed interconnection without condition.[222] Additionally, the Commission proposed to modify the supplemental review by including three screens: (1) The Minimum Load Screen; (2) the power quality and voltage screen; and (3) the safety and reliability screen.[223]

112. The Commission also proposed language in section 2.4.2 of the SGIP to clarify the requirements following the conclusion of the supplemental review. The Commission proposed that the Transmission Provider perform the supplemental review for a nonrefundable fee of $2,500.

2. General Comments on the Customer Options Meeting and the Supplemental Review

a. Comments

113. Several commenters support the Commission's proposed supplemental review reforms.[224] ITC expresses general support for the proposed changes in the customer options meeting and supplemental review process but offers several recommendations.[225] IREC supports the proposed supplemental review process with the optional use of ''hosting capacity.'' [226] IREC states that utilities operating with high distributed generation penetrations have found that with additional time and screening, they are able to safely interconnect generators without full study (*e.g.,* California and Hawaii have adopted screens similar to those in the NOPR).[227] SEIA believes the proposed supplemental review reforms will support the interconnection of renewable generation needed to meet the demand created by state policies.[228] AWEA and IREC both assert that the

[217] Thomas Cleveland & Michael Sheehan, Updated Recommendations for FERC Small Generator Interconnection Procedures Screens (July 2010), *available at http://www.solarabcs.org/about/publications/reports/ferc-screens/pdfs/ABCS-FERC_studyreport.pdf,* p. 2 and Appendix I.

[218] We note that inverter-based wind turbines would not be excluded from the 2 MW to 5 MW thresholds shown in the Fast Track eligibility table adopted in this Final Rule.

[219] If a Transmission Provider prefers to adopt Fast Track eligibility criteria that differ from the table adopted in this Final Rule and that would accomplish AWEA's proposal, it may propose to do so as part of its compliance filing. Transmission Providers that propose to adopt different Fast Track eligibility criteria must submit compliance filings demonstrating that their proposed approach is consistent with or superior to the table adopted in this Final Rule, or meets another standard allowed in section V of this Final Rule.

[220] IREC at 14–15, Public Interest Organizations at 11.

[221] The Commission adds the following language to the first paragraph of section 2.1 of the SGIP:

However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Fast Track screens in section 2.2.1 below of the Supplemental Review screens in section 2.4.1 below.

[222] Section 2.3.2 of the SGIP adopted in Order No. 2006 gave the Transmission Provider the discretion to offer to perform a supplemental review if the ''Transmission Provider concludes that the supplemental review might determine that the Small Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process.''

[223] For the full text of the proposed screens, see section 2.4 of Appendix C to the NOPR. ''Minimum Load Screen'' refers to SGIP section 2.4.1.1 of Appendix C to the NOPR or SGIP section 2.4.4.1 of Appendix C to the Final Rule. The Minimum Load Screen tests whether the aggregate Generating Facility capacity on a line section is less than 100 percent of minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility (using 100 percent of daytime minimum load for solar PV generators with no battery storage and 100 percent of absolute minimum load for all other Small Generating Facilities).

[224] AWEA, CEP, Clean Coalition, DCOPC, ELCON, FCHEA, IREC, NRG, Public Interest Organizations, SEIA, and UCS.

[225] ITC at 11.

[226] IREC at 17. ''Hosting capacity'' is an alternative approach to the interconnection procedures in the NOPR under which the Transmission Provider calculates the maximum aggregate generating capacity that a distribution circuit can accommodate at a proposed Point of Interconnection without requiring the construction of facilities by the Transmission Provider on its own system and while maintaining the safety, reliability and power quality of the distribution circuit. *See infra* P 0.

[227] IREC at 19.

[228] SEIA at 6.

proposed revisions to the supplemental review process are a well-designed solution for efficiently handling increased volume and penetrations of distributed generation without compromising safety and reliability.[229] NRG Companies states the revised supplemental review process will provide transparency and allow small generators to avoid lengthy and costly interconnection procedures.[230]

114. CPUC notes that the proposed supplemental review screens are modeled after California's Electric Rule 21 and recommends that the Commission adopt the supplemental review screens.[231] CPUC states that the proposed supplemental review screens will harmonize state and federal interconnection standards, allow for increased penetration of Small Generating Facilities, and are consistent with safe and reliable electric service.[232]

115. MISO warns that although the additional screens are designed to create more cohesiveness between the parties and to increase the movement of projects through the interconnection queue, they can instead lead to conflict over the underlying data used in the screens.[233]

116. NYISO & NYTO state that the time required to perform the supplemental review screens would be better spent conducting an Interconnection Feasibility Study.[234] According to NYISO & NYTO, requiring that the performance of the additional screens could exacerbate, rather than mitigate, the time and costs associated with the interconnection process and would not preclude the possibility that the proposed Small Generating Facility may still be required to participate in the Study Process.[235]

b. Commission Determination

117. The Commission adopts the proposed revisions to the customer options meeting and the supplemental review, with some modifications as discussed below, including three supplemental review screens (the Minimum Load Screen,[236] the voltage and power quality screen[237] and the safety and reliability screen[238]). The Commission is persuaded by the comments and by the apparent successful implementation thus far of a similar process in California that the revised customer options meeting and supplemental review will enhance transparency and consistency of the supplemental review process and thus ensure that interconnection remains just and reasonable and not unduly discriminatory, particularly in regions with increasing penetrations of Small Generating Facilities. The Commission further finds that the SGIP retains sufficient flexibility (e.g., through the initial Fast Track screens in section 2.2.1) to meet the needs of regions that do not have significant penetrations of Small Generating Facilities. The Commission believes adopting the revisions to the customer options meeting and the supplemental review best balances the benefits of interconnecting Small Generating Facilities under the quicker, less costly Fast Track Process with the needs of Transmission Providers to protect the safety and reliability of their systems.

3. Minimum Load Screen (SGIP Section 2.4.4.1)

a. Comments

118. IREC, SEIA, the Vote Solar Initiative (VSI) and UCS support including the Minimum Load Screen in the supplemental review.[239] IREC contends that minimum load is an appropriate evaluation standard in the SGIP supplemental review because minimum load is a more accurate metric for evaluating system risk, and many utilities have or soon will have a year or more of minimum load data on some circuits.[240] According to IREC, utilities that are not experiencing high penetrations of distributed generation will not have a need to determine minimum load in the near term and will have time to refine their process for evaluating minimum load as distributed generation penetration grows in their service territory.[241]

119. SEIA states that without the Minimum Load Screen, ratepayers will bear the cost of unnecessarily costly and complex interconnection processes, and that achievement of the states' clean energy policies may be jeopardized.[242] Public Interest Organizations state that the Minimum Load Screen will accommodate higher penetrations of distributed generation without creating significant backlogs in study queues.[243]

120. SEIA and AWEA state that the Minimum Load Screen, which is similar to CPUC Rule 21, is a national best practice for distributed generation penetration levels and demonstrates that aggregate interconnected generating capacity can be 100 percent of minimum load on a distribution line section without impairing safety or reliability.[244] SEIA notes that the California Utilities called Rule 21 ''a model for use in reforming the Fast Track [P]rocess''[245] and that EEI indicated support for a minimum load screen similar to the one in Rule 21 in the context of a supplemental review process.[246] SEIA states that California's experience with Rule 21 demonstrates the viability of the Minimum Load Screen on a national level so there is no need for a lower standard.[247] Given the widespread support for the Minimum Load Screen, NREL analysis, the CPUC's adoption of the Rule 21 minimum load screen, and the technical feasibility and protections afforded by the other proposed supplemental review screens, SEIA urges the Commission to adopt the proposed supplemental review process, including the Minimum Load Screen.[248] Clean Coalition credits the Rule 21 supplemental review with leading to significant improvements in the Fast Track Process, including allowing larger projects to succeed under the Fast Track Process than would be allowed under the 15 Percent Screen.[249] FCHEA recommends that all types of distributed generation, especially stationary fuel cells, be included in the new screen.[250]

121. NREL considers minimum daytime load, as included in the proposed Minimum Load Screen, to be the appropriate approach for solar PV systems because it more precisely estimates the ratio between generation and load on a line section.[251]

122. NRECA, EEI & APPA and NYISO & NYTO do not support the Minimum Load Screen, stating that minimum load is not a critical system operating criterion and cannot be determined accurately because line section

[229] AWEA at 4 and IREC at 17.

[230] NRG at 4.

[231] CPUC at 6–7. California Electric Rule 21 is the California distribution level interconnection rules and regulations (Rule 21). It includes supplemental review screens similar to those proposed by the Commission in the NOPR.

[232] CPUC at 7.

[233] MISO at 8–9.

[234] NYISO & NYTO at 20–21.

[235] *Id.* at 21.

[236] *See* SGIP section 2.4.4.1 of Appendix C attached hereto.

[237] *See* SGIP section 2.4.4.2 of Appendix C attached hereto.

[238] *See* SGIP section 2.4.4.3 of Appendix C attached hereto.

[239] IREC at 17; SEIA at 4–5; VSI at 2; and UCS at 18–19.

[240] IREC at 17–18.

[241] *Id.* at 18–19.

[242] SEIA at 6.

[243] Public Interest Organizations at 13–14.

[244] SEIA at 6; AWEA at 4.

[245] SEIA at 6 (citing comments of the California Utilities in Docket No. AD12–17–000 at 4).

[246] *Id.* at 6–7 (citing EEI comments in Docket No. AD12–17–000 at 11, n. 10).

[247] *Id.* at 10.

[248] *Id.*

[249] Clean Coalition at 7.

[250] FCHEA at 2.

[251] NREL at 4.

monitoring is typically unavailable.[252] NRECA, EEI & APPA contend that the investment needed to obtain the data would be unacceptably high unless a utility has other operational reasons for investing in the measuring devices needed to acquire the data.[253]

123. Duke Energy expresses concern about the proposal to calculate daytime minimum load, stating that calculating minimum load when actual load data are not available may not adequately reflect system conditions.[254]

124. SEIA claims that NRECA, EEI & APPA's NOPR comments that describe how utilities use other sources of information to estimate minimum load data demonstrate that the proposed *pro forma* SGIP gives Transmission Providers sufficient flexibility to perform the Minimum Load Screen when minimum load data are not available.[255]

125. UCS asserts that the Commission should order utilities to start collecting daytime minimum load data in areas where distributed generation penetration levels of five percent of peak load or higher are proposed.[256]

126. NRECA, EEI & APPA contend that utilities must take an ''appropriately cautious'' approach to integrating distributed generation because the industry is still in the early stages of evaluating the impact that increased distributed generation will have on transmission and distribution systems.[257] They claim that rapid integration of distributed generation can cause the flow direction to change and introduce significant reliability concerns. They argue that while interconnection studies may identify reverse power flow issues and possible solutions, more detailed studies of individual line protection and control devices are necessary to prevent damage to Transmission Provider equipment.[258]

127. NRECA, EEI & APPA dispute SEIA's claims that the Minimum Load Screen is widely supported, offering their own opposition as evidence to the contrary. They also urge the Commission to give substantial weight to Transmission Provider comments about the Minimum Load Screen because they are responsible for ensuring the safety and reliability of their systems.[259]

128. NRECA, EEI & APPA assert that the Minimum Load Screen: (1) Is not consistent with Good Utility Practice because utilities typically do not operate their systems at or beyond the threshold of when problems are known to occur; (2) limits the utility's future flexibility to move loads when new facilities are built in an area and limits the ability to deploy additional line sectionalizing devices for reliability enhancement; (3) requires the utility to maintain some amount of minimum load on a feeder where a distributed generation project has been operating and a large load is lost; and (4) results in additional costs being recovered from all other customers to rectify the problems, requiring additional infrastructure investment to move loads by constructing new feeder ties or other needed solutions.[260] Therefore, they urge the Commission to retain the existing 15 Percent Screen.[261]

129. Duke Energy believes that the Minimum Load Screen may not provide a sufficient margin of safety to account for the variability of load on a distribution circuit and for the variability of output of certain types of Small Generating Facilities.[262] Duke Energy asserts that the intermittent nature of PV generation connected on distribution lines may interfere with smart grid applications and load monitoring equipment, and may cause restoration schemes and voltage and reactive power schemes to operate improperly. Duke Energy states that the existing 15 Percent Screen has a safety margin for minimum load built into the screen, which minimizes the negative effects of variable generation.[263] Duke Energy also comments that the Minimum Load Screen will require utilities to estimate minimum load and that these estimates may involve high rates of error.[264]

130. IREC argues, however, that Transmission Providers infrequently have to transfer load between circuits and can retain flexibility on a particular circuit by identifying this need through the application of the additional supplemental review screens.[265] IREC further states that the safety, reliability, and power quality screens in the supplemental review process, along with providing 20 business days for the Transmission Provider to perform the supplemental review, provide utilities with sufficient time and flexibility to evaluate a proposed generator and enable more generators to be interconnected safely without a full study.[266]

131. IREC asserts that it is inappropriate to view the Minimum Load Screen in isolation from the other supplemental review screens.[267] IREC argues that when viewed together, the supplemental review screens provide the flexibility to identify circumstances where high penetrations of distributed generation may require additional study.[268] SEIA and Public Interest Organizations similarly assert that even if a proposed Small Generating Facility passes the Minimum Load Screen, it would be subject to additional study if it failed either of the other two screens, which address reliability and operational flexibility.[269] IREC states that inverter-based systems minimize risks that may arise at higher penetrations.[270] IREC further states that the Minimum Load Screen does not increase the risk of problems related to load changes and notes that problems related to load changes could also be raised in relation to projects that undergo the Study Process (*i.e.,* increasing the number of generators that are able to interconnect without full study does not exacerbate the problem associated with changes in load, nor would requiring full study for more generators reduce this risk).[271] SEIA states that the Minimum Load Screen is conservative because the likelihood of every generator on a circuit generating power at its nameplate capacity while the circuit's load is simultaneously at its minimum is extremely rare.[272]

132. NRECA, EEI & APPA state that if the Commission adopts a minimum load screen, 67 percent for such a screen is a reasonable starting point because it provides an appropriate initial buffer to protect safety, reliability and power quality, and is consistent with the configuration of many distribution systems.[273] Further, they claim that any threshold higher than 67 percent of minimum load for those distribution circuits involving both inverter-based PV and rotating generator machines would impose an unacceptable threat to safety, reliability, and power quality.[274] They argue that no more than a 33 percent minimum load screen is

[252] NRECA, EEI & APPA at 23 and NYISO & NYTO at 21.

[253] NRECA, EEI & APPA at 23.

[254] Duke Energy at 11–12.

[255] SEIA Reply Comments at 4.

[256] UCS at 20.

[257] NRECA, EEI & APPA Reply Comments at 7.

[258] *Id.* at 6.

[259] *Id.* at 10.

[260] NRECA, EEI & APPA at 26.

[261] *Id.* at 7.

[262] Duke Energy at 10.

[263] *Id.* at 11.

[264] *Id.* at 11–12.

[265] IREC at 24.

[266] *Id.* at 17.

[267] *Id.* at 22.

[268] *Id.*

[269] Public Interest Organizations at 14 and SEIA at 8.

[270] IREC at 23.

[271] *Id.*

[272] SEIA at 8–9.

[273] NRECA, EEI & APPA Reply Comments 9.

[274] NRECA, EEI & APPA at 7, 25.

appropriate for areas or applications involving only rotating machines.[275] They state that the Commission could follow the Massachusetts Department of Public Utilities' procedure by adopting a 67 percent minimum load screen and holding an annual technical workshop with interested parties to determine whether the percentage chosen for the screen is working as planned or determine whether the chosen percentage should be revised.[276]

133. SEIA contends that the 67 percent Minimum Load Screen is inappropriate because the only rationale presented was the adoption of this screen on an interim basis in Massachusetts.[277] Sandia and SEIA state that the 67 percent minimum load screen adopted in Massachusetts serves only as an interim standard while a working group investigates the appropriate level for a minimum load screen.[278] SEIA asserts that holding annual technical conferences to reassess the Minimum Load Screen will impose uncertainty on utilities and developers and will burden the Commission.[279]

134. Sandia, IREC and SEIA argue that a 67 percent minimum load screen lacks technical justification.[280] Sandia and IREC note that the 67 percent minimum load screen adopted in Massachusetts on an interim basis was derived from a Sandia report on anti-islanding, and that it is not appropriate to use the screen to determine if further study of a Small Generating Facility is required.[281] IREC asserts that a 67 percent minimum load screen would do little to improve the interconnection process.[282]

135. SEIA further states that NREL determined that if aggregate generation on a line section is below 100 percent of minimum load, the risk of power backfeeding beyond the substation is minimal; therefore power quality, voltage control and other safety and reliability concerns may be addressed without a full study of the proposed Small Generating Facility.[283] SEIA also notes that at the July 17, 2012 technical conference,[284] NREL stated that there are systems designed to work well with aggregate generation in excess of 100 percent of minimum load and there is no ''hard and fast ceiling'' that exceeding 100 percent of daytime minimum load would cause a system to fail.[285]

136. Sandia states that there are many circuits with aggregated PV that are operating above 100 percent of minimum load, but the risk of unintentional islanding of inverter-based distributed generation is extremely low.[286] Therefore, Sandia asserts that, for distributed generation with anti-islanding capability,[287] a screening threshold of 100 percent of minimum load is sufficiently conservative to mitigate the risk of unintentional islanding.[288]

137. NREL states that it has documented examples of PV systems operating at levels over 300 percent of minimum daytime load.[289] NREL believes that utilities should be encouraged to increase this penetration screen percentage on line sections with feeders that have shorter average distances to a substation, lower average impedance, and a lower average stiffness factor.[290]

138. MISO suggests that for facilities less than 100 kV, it may be more efficient to assess the impact of a possible back-feed event rather than conduct a Minimum Load Screen analysis.[291]

139. VSI asserts that the Minimum Load Screen can be implemented without the other supplemental review screens for two reasons: (1) Minimum daytime loads tend to occur in the early morning hours and are not coincident with maximum solar output; and (2) the diversity of solar installations adds to the safety margin because the varying size, angles, orientations, and regional cloud cover make it unlikely that the generation of all the solar installations will peak at the same time.[292]

140. NRECA, EEI & APPA suggest deleting the proposed requirement to consider only net export energy from small generators that serve onsite load (proposed SGIP section 2.4.1.1.2) because it requires consideration of the net export of power by the Small Generating Facility that may flow on the Transmission Provider's system rather than total output of the Small Generating Facility in the application of the Minimum Load Screen. They argue that on-site load can vary and cannot be counted on to consume some of the Small Generating Facility's output. The commenters also state that relying on reverse power relays alone does not mitigate all concerns related to the potential impact of reverse power flow on the Transmission Provider's system.[293]

b. Commission Determination

141. The Commission adopts the Minimum Load Screen [294] as proposed in the NOPR, with modifications as discussed below. We appreciate the concerns of Transmission Providers with regard to the Minimum Load Screen, but believe that the Minimum Load Screen is sufficiently conservative, particularly when viewed together with the other two supplemental review screens. Taken as a whole, the supplemental review screens provide the flexibility to identify circumstances when additional studies may be required while avoiding an unjust and unreasonable increase in expense and delay in interconnection. That is, the three screens in the supplemental review are designed to strike a balance between handling the increased volume of interconnection requests and penetrations of small generators and maintaining the safety and reliability of the electric systems.

142. The Minimum Load Screen is used in assessing whether an Interconnection Customer that initially failed the Fast Track screens may still interconnect under the Fast Track Process. If the aggregate generating capacity on a line section, including the proposed Small Generating Facility, is less than 100 percent of minimum load, there are two additional screens, the voltage and power quality screen and the safety and reliability screen, that the Small Generating Facility must pass to be interconnected. Regarding NRECA, EEI & APPA's assertion that the use of 100 percent of minimum load limits the flexibility to move loads and the ability to deploy additional sectionalizing

[275] *Id.* at 25.

[276] *Id.*

[277] SEIA Reply Comments at 3.

[278] Sandia at 4 and SEIA at 9 (citing *Order on the Distributed Generation Working Group's Redlined Tariff and Non-Tariff Recommendations,* Massachusetts Department of Public Utilities 11–75–E at 34).

[279] SEIA Reply Comments at 3.

[280] IREC at 20–21; Sandia at 4; and SEIA at 9.

[281] IREC at 20–21 and Sandia at 4, citing M. Ropp and A. Ellis, *Suggested Guidelines for Assessment of DG Unintentional Islanding Risk,* Sandia National Laboratories (March 2013), p. 5, available at: *http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2012-1365-v2.pdf.*

[282] IREC at 21.

[283] SEIA at 7 (citing NREL, Technical Report: Updating Small Generator Interconnection Procedures for New Market Conditions 30 (Dec. 2012)).

[284] *See supra* P 0.

[285] SEIA at 7 (citing Technical Conference Transcript at 92:15–21).

[286] Sandia at 5.

[287] *Id.* at 4–5 (noting that all new UL 1741-listed inverter-based distributed generation must have anti-islanding capability).

[288] *Id.* at 5.

[289] NREL at 4.

[290] *Id.* at 5, stiffness factor is defined as the available utility fault current divided by the distributed generation rated output current at the point of common coupling.

[291] MISO Comments at 9.

[292] VSI at 3.

[293] NRECA, EEI & APPA, Appendix B at 2.

[294] *See* SGIP section 2.4.4.1 of Appendix C attached hereto.

devices for reliability enhancement, we note that one of the factors to be considered in the safety and reliability screen of the supplemental review asks whether operational flexibility is reduced by the proposed Small Generating Facility (see SGIP section 2.4.1.3.5). Therefore, the Commission agrees with IREC that this concern can be evaluated under the safety and reliability screen.

143. The Commission finds that a 100 percent minimum load screen more appropriately balances these considerations than the 33 and 67 percent minimum load screens proposed by NRECA, EEI & APPA. We note that a 33 percent minimum load screen would be even more conservative than the existing 15 Percent Screen (which approximates a 50 percent minimum load screen).[295]

144. The Commission acknowledges the concerns of NRECA, EEI & APPA and NYISO & NYTO that minimum load does not represent a critical system operating criterion so currently minimum load data are typically not measured and/or recorded, but the Commission agrees with IREC that minimum load is a more accurate metric for evaluating system risk posed by a potential interconnection than peak load. The Commission also acknowledges IREC's comment that Transmission Providers experiencing high penetrations of Small Generating Facilities have or soon may have a year or more of minimum load data on some circuits. Contrary to UCS' request and in response to NRECA, EEI & APPA's comments, the Commission is not at this time requiring Transmission Providers to purchase equipment or otherwise make investments to obtain minimum load data. The adopted reform gives the Transmission Provider the flexibility to calculate, estimate or determine minimum load if data are not available. Further, the language allows the Transmission Provider not to perform the Minimum Load Screen if data are unavailable or if it is unable to calculate, estimate or determine minimum load.[296]

145. Regarding Duke Energy's concern that calculations of daytime minimum load may not adequately reflect system conditions, the Commission clarifies that if the Transmission Provider is concerned that its minimum load calculations may not adequately reflect system conditions in a particular instance and the Transmission Provider is unable to correct for any inaccuracies in the calculations or estimate or determine minimum load in some other way, the Transmission Provider may elect not to perform the Minimum Load Screen. However, the Transmission Provider must provide the reason it is unable to perform the screen to the Interconnection Customer, in accordance with SGIP section 2.4.4.1.

146. Regarding Duke Energy's assertion that the 15 Percent Screen should be maintained because it includes a safety margin that minimizes the negative effects of intermittent generation (such as problems with smart grid applications, load monitoring equipment, restoration schemes, and voltage and reactive power control schemes), the Commission finds that such issues are appropriately addressed under the voltage and power quality and the safety and reliability screens of the supplemental review.

147. The Commission acknowledges comments that utilities study the aggregate nameplate generation on the system relative to the Small Generating Facility output, that on-site load can vary, and that Transmission Providers should not net out on-site load when applying the Minimum Load Screen. Rather than deleting proposed section 2.4.1.1.2 [297] entirely, however, the Commission changes ''onsite electrical load'' to ''station service load,'' since station service load is typically netted out when considering the aggregate generation. Further, the Commission modifies section 2.4.4.1 to clarify that on-site load served by a proposed Small Generating Facility should be accounted for in minimum load for the purpose of applying the Minimum Load Screen.

148. Finally, the Commission disagrees with VSI that the Minimum Load Screen alone is generally sufficient to determine if a Small Generating Facility may be interconnected safely and reliably without undergoing full study. The additional screens are necessary to ensure the safety and reliability of the proposed interconnection and to allow Transmission Providers the flexibility to identify issues that may be unique to a particular Small Generating Facility.

4. Voltage and Power Quality Screen and Safety and Reliability Screen (SGIP Sections 2.4.4.2 and 2.4.4.3)

a. Comments

149. The Commission received a number of comments regarding the details of the proposed voltage and power quality screen [298] and the safety and reliability screen.[299] NYISO & NYTO are concerned that these screens could be passed by a single generator, but aggregate distributed generation in an area could result in voltage and/or power quality issues to neighboring customers.[300]

150. ITC notes that it has performed power quality screens and asserts that performing the voltage and power quality screen requires monitoring equipment that is typically found on distribution-level systems and adding it to ITC's transmission-level system would present ''substantial logistical problems.'' [301] ITC states that performing the power quality and voltage screen would impose costs in excess of the $2,500 supplemental review fee without providing commensurate benefits.[302] Similarly, NRECA, EEI & APPA state that the power quality and voltage screen is difficult to perform without detailed engineering analysis and the $2,500 supplemental review fee would not cover the cost of performing the screen.[303] ITC does not recommend increasing the supplemental review fee to cover the cost of performing this screen. Rather, ITC recommends that the voltage and power quality screen should be an optional analysis performed at the request of individual Interconnection Customers on a fee-for-service basis. Alternatively, ITC suggests that the inclusion and precise methodology of this screen should be left to the discretion of individual ISOs/RTOs.[304]

151. NRECA, EEI & APPA note that the voltage and power quality screen does not specify if the screen applies at the point of common coupling or at the Point of Interconnection.[305]

152. NRECA, EEI & APPA suggest revising the screen as follows:

[295] The 15 Percent Screen can be viewed as a ''rule of thumb'' that minimum load is approximately 30 percent of peak load on a given line section with a 50 percent safety margin. *See* Nat'l Renewable Energy Lab, *Updating Interconnection Screens for PV System Integration* 2 (Feb. 2012), *available at http://www.nrel.gov/docs/fy12osti/54063.pdf.*

[296] Under section 2.4.4 of the SGIP adopted herein, if a Transmission Provider is unable to perform the Minimum Load Screen, it must notify the Interconnection Customer to obtain the Interconnection Customer's permission to continue the supplemental review (*see infra* P 0), to terminate the supplemental review or to withdraw the interconnection request. Further, in section 2.4.4.1 of the SGIP, when the Transmission Provider notifies the Interconnection Customer of the results of the supplemental review, it must include the reason that it is unable to perform the Minimum Load Screen.

[297] Section 2.4.4.1.2 in the SGIP adopted herein.

[298] *See* SGIP section 2.4.1.2 of Appendix C to the NOPR.

[299] *See* SGIP section 2.4.1.3 of Appendix C to the NOPR.

[300] NYISO & NYTO at 21.

[301] ITC at 13–14.

[302] *Id.* at 13–15.

[303] NRECA, EEI & APPA, Appendix B at 3.

[304] ITC at 13–15.

[305] NRECA, EEI & APPA, Appendix B at 3.

2.4.1.2 In aggregate with existing generation on the line section:

~~(1)~~2.4.1.2.1 the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions such that load on the Transmission Provider's transformer with automatic voltage control or line voltage regulator is 20% greater than the aggregate generation on the line section;

~~(2)~~2.4.1.2.2 the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and

~~(3)~~2.4.1.2.3 the harmonic levels meet IEEE Standard 519 limits at the Point of Interconnection.[306]

153. NRECA, EEI & APPA recommend adding the following final sentence to proposed SGIP section 2.4.1.3: ''If any one or more of the following safety and reliability protection test screens fail, then proceed to a feasibility and/or system impact study in [s]ections 3.3 and 3.4.'' [307]

154. In addition, NRECA, EEI & APPA recommend adding the following to proposed section 2.4.1.3: ''For safety and reliability protection of the line section, the aggregate generation existing, in queue for installation, and being proposed shall be considered for evaluating the generation types within the regional limits established for interactive system operability as specified by the Transmission Provider.'' [308]

155. Finally, NRECA, EEI & APPA suggest deleting proposed SGIP section 2.4.1.3.3, which examines the proposed interconnection's proximity to the substation and the class of conductor cable between the substation and the proposed Point of Interconnection, because different distribution line constructions can affect system impedance differently.[309]

b. Commission Determination

156. The Commission adopts the NOPR proposal for the voltage and power quality screen and the safety and reliability screen, as modified below.

157. Regarding NYISO & NYTO's concern that the voltage and power quality and safety and reliability screens could be passed by a single generator, but aggregate distributed generation in an area could result in voltage and/or power quality issues to neighboring customers, we note that sections 2.4.4.2 and 2.4.4.3 of the SGIP adopted herein specify that the proposed Small Generating Facility should be evaluated with existing aggregate generation on a line section, so any issues associated with aggregate generation should emerge as a result of the performance of these screens.

158. In response to ITC's comment that the cost of the voltage and power quality screen may be greater than the benefit associated with the screen and NRECA, EEI & APPA's comment that this screen is difficult to perform without detailed engineering analysis, we will permit Transmission Providers to propose an alternative methodology for performing this screen when submitting filings in compliance with this Final Rule.[310]

159. In response to NRECA, EEI and APPA, the Commission clarifies that a proposed interconnection being evaluated under the voltage and power quality supplemental review screen must meet the requirements as specified in the applicable IEEE standards. Therefore, we delete ''at the Point of Interconnection'' from section 2.4.4.2 of the *pro forma* SGIP adopted herein so there is not a conflict between the SGIP and the IEEE standards.

160. The Commission declines to add ''such that load on the Transmission Provider's transformer with automatic voltage control or line voltage regulator is 20 [percent] greater than the aggregate generation on the line section'' to section 2.4.4.2 of the SGIP adopted herein as suggested by NRECA, EEI & APPA because the commenters do not provide an explanation or support for making this revision. For the same reasons the Commission declines to add the language under section 2.4.4.3 as proposed by NRECA, EEI & APPA.

161. Finally, the Commission acknowledges NRECA, EEI & APPA's concerns regarding different distribution line constructions affecting system impedance differently. Therefore, in order to account for differences in distribution systems and to make this section consistent with the Fast Track eligibility table in section 2.1 of the SGIP, the Commission adopts the following language in section 2.4.4.3.3 of the SGIP:

> Whether the proposed Small Generating Facility is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

5. Supplemental Review Screen Order (SGIP Section 2.4.2)

a. Comments

162. NRECA, EEI & APPA argue that the safety and reliability screen should be performed first in the supplemental review, and that a Small Generating Facility that fails the safety and reliability screen should be required to proceed directly to the Study Process.[311] They assert that Transmission Providers could be spared the time and cost of performing the remaining supplemental review screens if it is known at the beginning of the supplemental review that interconnection of a Small Generating Facility poses a threat to the safety and reliability of the system.[312]

163. SEIA opposes any change to the order in which the supplemental review screens are applied.[313] SEIA contends

[306] *Id.*

[307] *Id.*

[308] *Id.*

[309] *Id.*

[310] *See infra* section V.

[311] NRECA, EEI & APPA at 26.

[312] *Id.* at 27.

[313] SEIA Reply Comments at 2.

that the Commission's supplemental review screens are proposed to be completed in the same manner as the Rule 21 screens.[314] Thus, SEIA contends that the Commission proposed that the three supplemental review screens be conducted in the following order: (1) Minimum Load Screen; (2) power quality and voltage screen; and (3) safety and reliability screen. SEIA states that the Commission should maintain this order to avoid inconsistencies between the SGIP and Rule 21.[315] SEIA also argues that changing the order of the screens will not save utilities the time and expense of performing additional screens because the Interconnection Customer bears the cost of the supplemental review, not the utility.[316]

b. Commission Determination

164. In order to allow for flexibility in the supplemental review process and to potentially save the Interconnection Customer the cost of unnecessary supplemental review screens, the Commission adopts language in SGIP section 2.4 that allows the Interconnection Customer to specify an order in which the supplemental review screens are to be performed, as well as a requirement that the Transmission Provider notify the Interconnection Customer if the Small Generating Facility fails any of the screens and obtain the Interconnection Customer's permission to continue with the supplemental review for informational purposes or in order to determine if the interconnection may proceed with minor modifications to the Transmission Provider's system.[317] The Commission finds, contrary to arguments by NRECA, EEI & APPA and SEIA, that because the Interconnection Customer is paying for the screens, the Interconnection Customer should be able to specify the order in which the Transmission Provider performs the screens. However, we note that any delay in obtaining permission from an Interconnection Customer under these requirements may impact the Transmission Provider's ability to complete the supplemental review within the specified timeframe. To avoid the possibility of any such delays, an Interconnection Customer may provide instructions for how to proceed after a supplemental review screen failure at the time the Interconnection Customer accepts the Transmission Provider's offer to perform the supplemental review under section 2.4.1 of the *pro forma* SGIP adopted herein.

6. Supplemental Review Fee (SGIP Sections 2.4.1 and 2.4.3)

a. Comments

165. NREL believes that the $2,500 supplemental review fee strikes a balance in cost and time and supports the fee.[318] IECA states that the $2,500 fee is appropriate.[319]

166. NRECA, EEI & APPA and ISO–NE do not believe the $2,500 fee covers the cost of performing the supplemental review.[320] NRECA, EEI & APPA recommend, at the very least, that the $2,500 fee represents a base payment, and that the fee be adjusted for inflation with either the Consumer Price Index or the Handy-Whitman Index.[321] ISO–NE requests regional flexibility to determine a fee that adequately covers the supplemental review costs.[322]

167. NYISO & NYTO estimate the actual cost of a supplemental review will be approximately equivalent to the cost of an average interconnection feasibility study for a Small Generating Facility ($30,000), and therefore claim that the proposed $2,500 supplemental review fee is insufficient to cover the cost of the review.[323] NYISO & NYTO propose either adopting a higher supplemental review fee or retaining the existing requirement that the Interconnection Customer provide a deposit for the estimated cost of the work, which would be refunded, based on actual costs.[324]

168. ITC and PJM assert that Interconnection Customers should be required to pay the Transmission Provider for its actual cost incurred in performing the supplemental review rather than a flat $2,500 fee, which may result in over- or under-recovery of the Transmission Provider's actual incurred expenses.[325] ITC believes the $2,500 fee will be ''consistently and substantially less than the true cost'' of performing the proposed supplemental review.[326] DCOPC requests that the Commission ensure that the Interconnection Customer is solely responsible for all supplemental review costs rather than allocating these costs to load.[327] If the Commission does not require the Interconnection Customer to pay the actual cost of the supplemental review, PJM requests clarification by the Commission that allocating costs in excess of the $2,500 review fee to load is just and reasonable.[328]

169. ITC recommends that the Commission adopt a ''deposit/not-to-exceed'' fee structure whereby the Interconnection Customer provides an initial deposit and identifies an amount that the Transmission Provider is not to exceed while it prepares the supplemental review.[329] ITC proposes that the supplemental review costs could be trued-up based on actual incurred costs after the study is complete.[330]

b. Commission Determination

170. The Commission agrees with commenters that the Interconnection Customer should be responsible for the actual cost of conducting the supplemental review, therefore, the Commission adopts a supplemental review fee based on actual costs. We are concerned that because the supplemental review is not based solely on information already available to the Transmission Provider (unlike the pre-application report), there may be significant cost differences between supplemental reviews for different projects. Therefore, a fixed fee would result in Interconnection Customers with smaller supplemental review costs subsidizing Interconnection Customers with larger supplemental review costs.

171. Similar to the supplemental review and other processes (e.g., the feasibility study and the system impact study) in the *pro forma* SGIP,[331] prior to performing the supplemental review, the Transmission Provider will be required to provide the Interconnection Customer with a good faith estimate of the cost to perform the supplemental review, and the Interconnection Customer will be required to pay this amount as a deposit in advance of the supplemental review. After the supplemental review is complete, the Transmission Provider and the Interconnection Customer will reconcile any difference between the deposit paid by the Interconnection Customer and the actual cost to perform the supplemental review.

172. Consistent with the Commission's determination on SGIP study cost responsibility in Order No. 2006, the Interconnection Customer will

[314] *Id.* at 5.

[315] *Id.*

[316] *Id.*

[317] *See infra* P 0.

[318] NREL at 4.

[319] IECA at 5.

[320] NRECA, EEI & APPA at 22–23; ISO–NE at 17.

[321] NRECA, EEI & APPA at 22–23.

[322] ISO–NE at 17.

[323] NYISO & NYTO at 19.

[324] *Id.* at 19–20.

[325] ITC at 12; and PJM at 12.

[326] ITC at 12.

[327] DCOPC at 7.

[328] PJM at 12.

[329] ITC at 12–13.

[330] *Id.* at 8, 12–13.

[331] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 187.

be required to pay for the supplemental review, regardless of the conclusions reached, rather than unreasonably shift this cost to other transmission customers that do not benefit from the review. However, whenever possible, the Transmission Provider should use existing information and studies instead of performing additional analyses for the supplemental review in order to reduce costs for the Interconnection Customer. Although the Interconnection Customer is not to be charged for such existing information and studies, it is responsible for costs associated with any new analysis and any modification to an existing analysis that are reasonably necessary to evaluate the proposed interconnection under the supplemental review.

173. We are not adopting ITC's proposal to allow Interconnection Customers to specify the maximum amount that the Transmission Provider may spend to prepare the supplemental review. Rather, the Commission believes that the Transmission Provider's good faith estimate of the cost to perform the review, along with the requirement described above that the Transmission Provider notify the Interconnection Customer upon failure of a supplemental review screen, provides the Interconnection Customer with a reasonable degree of transparency and cost certainty in the supplemental review process.

7. Process Following Completion of the Customer Options Meeting and the Supplemental Review (SGIP Sections 2.3.1, 2.4.4 and 2.4.5)

a. Comments

174. NRECA, EEI & APPA, MISO and ITC request additional clarification regarding what changes qualify as ''minor modifications'' to the Transmission Provider's system.[332] ITC requests that the Commission provide a cost threshold or a more extensive list of examples of what constitutes a minor modification.[333] NRECA, EEI & APPA believe that ''minor'' would mean that ''the proposed interconnection requires no construction of facilities by the Transmission Provider on its own system'' and refers to modifications such as ''changing meters, fuses, [and] relay settings'' on the Transmission Provider's system.[334]

175. NYISO & NYTO request that ''minor modifications'' only include upgrades that fall within the definition of Local System Upgrade Facilities in the NYISO tariff.[335] NYISO & NYTO also request that the Commission clarify the extent to which security is required for such modifications and clarify that the Transmission Provider will forward the Interconnection Customer an interconnection agreement that requires the Interconnection Customer to pay the costs of the required system modifications prior to interconnection and requests that the Commission make similar modifications to the proposed requirement in section 2.4.2 regarding the provision of an interconnection agreement when the interconnection only requires minor modifications.[336] NYISO & NYTO propose that the Commission also modify section 2.4.2 of the SGIP to require that an Interconnection Customer's interconnection request ''shall'' be evaluated under the Study Process if it requires more than minor modifications to the Transmission Provider's system or be withdrawn.[337]

176. NYISO & NYTO state that since the supplemental review is optional, an Interconnection Customer's failure to agree and pay for the supplemental review should not lead to the withdrawal of its interconnection request. They request that the Commission require that if an Interconnection Customer does not agree in writing and pay the supplemental review fee within 15 business days, its interconnection request shall be directed to the Study Process for evaluation.[338]

177. ISO–NE argues that requiring the Transmission Provider to provide the Interconnection Customer with an interconnection agreement within five business days of the customer options meeting when the Interconnection Customer agrees to pay for modifications to the Transmission Provider's system is problematic.[339] Further, ISO–NE asserts that the existing ten business day deadline for providing an interconnection agreement following supplemental review when modifications to the Transmission Provider's system are required is extremely tight and states that the Commission should not reduce this timeframe.[340]

178. PJM is concerned that Transmission Providers will not be able to provide an executable interconnection agreement within five business days if the Interconnection Customer chooses to move forward based on the non-binding good faith estimate to perform modifications to the Transmission Provider's system offered during the customer options meeting. PJM therefore requests that the Commission allow ten business days, which it believes will enable more projects to obtain a quick interconnection agreement.[341] PJM also asks that the Commission increase each of the timeframes concerning the provision of interconnection agreements in the current supplemental review process by adding five business days to each stated deadline to accommodate the greater number of interconnection agreements that may result from the proposed reforms to the Fast Track Process.[342]

179. Bonneville Power Administration (Bonneville) states that the supplemental review should include an examination of Affected Systems.[343]

180. Finally, NYISO & NYTO request that the Commission retain ''does not'' in section 2.2.4 of the SGIP in order to enable the Interconnection Customer to have a customer options meeting when the Transmission Provider has the capability to but does not determine from the initial screens that the proposed facility can be interconnected safely and reliability under current system conditions.[344] Section 2.2.4 of the SGIP currently states that the Transmission Provider will offer Interconnection Customers a customer options meeting if the proposed interconnection fails the Fast Track screens but the Transmission Provider ''does not or cannot'' determine that the facility could interconnect consistently with safety, reliability, and power quality standards. In the NOPR, the Commission proposes to replace ''does not or cannot determine'' with ''cannot determine.''

b. Commission Determination

181. The Commission adopts the NOPR proposal to govern the process after the supplemental screen(s) have

[332] ITC at 13; MISO at 8; and NRECA, EEI & APPA at 22 (citing the NOPR, 142 FERC ¶ 61,049 at P 33 (stating that the Transmission Provider must offer to perform minor modifications to its system and provide a non-binding estimate of the cost at the customer options meeting)).

[333] ITC at 13.

[334] NRECA, EEI & APPA at 22 (citing the proposed *pro forma* SGIP at sections 2.3.1 and 2.4.2).

[335] NYISO & NYTO at 19.

[336] *Id.*

[337] *Id.* at 20.

[338] *Id.*

[339] ISO–NE at 16.

[340] *Id.* at 16–17.

[341] PJM at 11.

[342] *Id.* at 12.

[343] Bonneville at 3–4. An Affected System is ''[a]n electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.'' SGIP, Attachment 1.

[344] NYISO & NYTO at 18.

been completed as modified below. We agree with NYISO & NYTO that section 2.4.5 of the SGIP should be modified to require that an Interconnection Customer's interconnection request ''shall'' be evaluated under the Study Process if it requires more than minor modifications to the Transmission Provider's system, and the Interconnection Customer does not withdraw its Small Generating Facility. To further clarify the outcome of the supplemental review process, the Commission adopts language in section 2.4.5 for the following circumstances: (1) The proposed interconnection passes the supplemental review screens and does not require construction of facilities by the Transmission Provider on its own system; (2) interconnection facilities or minor modifications to the Transmission Provider's system are required for the proposed interconnection to pass the supplemental review screens; and (3) the proposed interconnection would require more than interconnection facilities or minor modifications to the Transmission Provider's system to pass the supplemental review screens. In the first circumstance, the proposed interconnection passes the supplemental review screens, and the Interconnection Customer is provided with an interconnection agreement within ten business days of notification of the supplemental review results. In the second circumstance, the proposed interconnection passes the supplemental review screens, and, if the Interconnection Customer agrees to pay for the modifications to the Transmission Provider's system, the Interconnection Customer is provided with an interconnection agreement within 15 business days of receiving written notification of the supplemental review results. In the third circumstance, the proposed interconnection does not pass the supplemental review screens and must continue to be evaluated under the Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

182. The Commission affirms that, consistent with Order No. 2006, examples of ''minor modifications'' to the Transmission Provider's system in the context of the supplemental review include changing meters, fuses, and relay settings.[345] However, we also note that these are examples only and therefore minor modifications could include other items that the Transmission Provider determines could be made to its system safely and reliably without further study of the interconnection. Because ''minor modifications'' could include items other than the listed examples,[346] the Commission does not herein establish a cost threshold or a more extensive list of items that would qualify as ''minor modifications.'' We do, however, modify section 2.4.5 to include language that the Transmission Provider will provide an interconnection agreement to the Interconnection Customer if the Interconnection Customer agrees to pay for the modifications to the Transmission Provider's system, similar to the language in section 2.3.1 of the SGIP.

183. The Commission disagrees with NYISO & NYTO that the time spent on a supplemental review would be better spent on a feasibility study. The Commission acknowledges that a supplemental review could add to the overall time of the interconnection process if a project fails the supplemental review and must be evaluated under the Study Process. However, if the Small Generating Facility is able to be interconnected under the Fast Track Process as a result of undergoing supplemental review, the interconnection process will be much shorter when compared with the Study Process. Further, the Commission notes that the purpose of the supplemental review is to determine if the Small Generating Facility may be interconnected safely and reliably without undergoing full study, including a feasibility study.

184. We agree with NYISO & NYTO that since the supplemental review is optional, an Interconnection Customer's failure to agree and pay for the supplemental review should not lead to the withdrawal of its interconnection request. Therefore, we adopt language in section 2.4.1 of the SGIP stating that, if an Interconnection Customer does not agree in writing and pay the supplemental review fee within 15 business days, the Transmission Provider shall direct the interconnection request to the section 3 Study Process for evaluation unless it is withdrawn by the Interconnection Customer.

185. In response to comments that the five business day deadline for providing the Interconnection Customer with an interconnection agreement when the Interconnection Customer accepts the Transmission Provider's offer at the customer options meeting to perform modifications to the Transmission Provider's system and agrees to pay for these modifications is too short, the Commission revises the deadline in section 2.3.1 to ten business days as proposed by PJM. Further, the Commission also adopts a ten business day deadline in section 2.4.5.1 for provision of an interconnection agreement that requires no construction of facilities or minor modifications to the Transmission Provider's system to accommodate any increased volume of interconnection agreements associated with the Fast Track Process reforms adopted herein. Finally, the Commission adopts the 15 business day deadline in section 2.4.5.2 for provision of an interconnection agreement when interconnection facilities or minor modifications to the Transmission Provider's system are required, as proposed in the NOPR.[347] This provides an additional five business days beyond the deadline in section 2.4.1.3 of the *pro forma* SGIP adopted in Order No. 2006 and should accommodate any increased volume of interconnection agreements associated with the Fast Track Process reforms adopted herein.

186. The Commission notes that in order to interconnect under the Fast Track Process supplemental review, a Small Generating Facility must pass all three supplemental review screens. In order to minimize supplemental review costs, the Commission will require the Transmission Provider to notify the Interconnection Customer within two business days following the failure of a supplemental review screen and obtain the Interconnection Customer's permission to: (1) Continue with the supplemental review at the Interconnection Customer's expense for informational purposes or to determine if the proposed interconnection would require only interconnection facilities or minor modifications to the Transmission Provider's system and thus qualify for interconnection under the Fast Track Process in accordance with section 2.4.5.2 of the *pro forma* SGIP adopted under this Final Rule; (2) terminate the supplemental review and continue evaluating the interconnection request under the SGIP section 3 Study Process; or (3) terminate the supplemental review upon withdrawal of the interconnection request by the Interconnection Customer. The Commission extends the supplemental review timeline in section 2.4.4 of the

[345] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 159 and section 2.3.1 of the SGIP.

[346] ''Minor modifications'' could, in some circumstances, include construction of facilities by the Transmission Provider on its own system, provided that the Transmission Provider were able to determine without further study that such modifications are safe and reliable. Such circumstances may be rare, but we see no reason to foreclose their possibility completely.

[347] *See* section 2.4.2 of the SGIP in Appendix C to the NOPR.

SGIP to 30 business days to accommodate this process.

187. With regard to Bonneville's concern that the supplemental review should include an examination of Affected Systems, section 4.9 of the SGIP already directs Transmission Providers to consider Affected Systems during the Fast Track screens when possible. Accordingly, the Commission finds that Bonneville's proposal to amend section 2.2.1.1 of the SGIP is unnecessary.

188. Finally, the Commission agrees with NYISO & NYTO's request to keep ''does not or cannot'' in section 2.2.4 of the SGIP because it will enable the Interconnection Customer to have a customer options meeting when the Transmission Provider has the capability to but does not determine from the Fast Track screens that the proposed facility can be interconnected safely and reliably.

D. Review of Required Upgrades

1. Commission Proposal

189. The Commission proposed to give Interconnection Customers the opportunity to review and comment upon the upgrades the Transmission Provider finds necessary for interconnection.[348] The Commission also proposed that the Transmission Provider must provide ''supporting documentation, workpapers, and databases or data'' developed in preparation of the facilities study upon request.[349] These proposals would make the SGIP consistent with the LGIP with respect to providing comments on upgrades required for interconnection.

2. Comments

190. Many commenters support the Commission's proposal to allow Interconnection Customers to review and comment on the upgrades the Transmission Provider deems necessary for interconnection because it would facilitate communication and transparency in the interconnection process.[350] SEIA states that many parties are already familiar with the proposed process because it is based on the LGIP.[351] CREA states that the opportunity to provide written comments enables Interconnection Customers to understand the proposed upgrades, seek a professional review, and make comments to the Transmission Provider that must be considered.[352] FCHEA states that allowing the Interconnection Customer the opportunity to provide written comments on the network upgrades required for interconnection could significantly increase the amount of distributed generation.[353]

191. MISO states that its current generator interconnection procedures already provide for Interconnection Customer review and comment with respect to potential upgrades required for interconnection. Therefore, MISO does not oppose the Commission's proposed revisions to the *pro forma* SGIP so long as it would consider MISO's existing generator interconnection procedures to meet this requirement as it applies to small generator interconnections.[354]

192. ISO–NE., MISO and CAISO similarly request that the Commission accommodate previously approved regional variations.[355] CAISO states that, although its procedures are not entirely aligned with the Commission's proposal, its tariff provides all Interconnection Customers with the opportunity to submit written comments on both the phase I and phase II interconnection reports, which comply with the proposed reforms.[356] CAISO states that the Commission should recognize that variations from the proposed *pro forma* reforms may still be just and reasonable.[357]

193. NYISO explains that it does not permit written comments in its LGIP, but instead offers Interconnection Customers the opportunity to meet with NYISO and NYTO to discuss the results of the facilities study, which gives Interconnection customers ample opportunity to comment.[358] NYISO & NYTO thus propose that the Commission require a facilities study meeting instead of written comments.[359] NYISO & NYTO assert that a meeting would provide an opportunity for the Interconnection Customer to provide feedback without extending the process by a number of days or creating the expectation that the Transmission Provider will make changes to the facilities study based on the Interconnection Customer's comments.[360]

194. If the Commission requires written comments, NYISO & NYTO request that the Commission clarify that the Transmission Provider is not required to perform additional analysis or make other modifications based on the Interconnection Customer's comments, unless the Interconnection Customer agrees to pay for the additional studies required.[361]

195. VSI supports the inclusion of written Interconnection Customer comments in the Facilities Study Agreement but expresses concern that the comments may not be seriously considered by the Transmission Provider.[362] VSI and LES assert that Interconnection Customers should only be responsible for the cost of the minimum upgrades and interconnection facilities required to interconnect the small generator's project to prevent a Transmission Provider from knowingly or unknowingly making the interconnection upgrades prohibitively expensive.[363]

196. LES states that if a Transmission Provider wishes to install interconnection facilities in addition to those needed to interconnect the Interconnection Customer's project, the cost of those facilities should be included in the Transmission Provider's rate base and allocated to all system users. LES asserts that the cost of those upgrades should not be imposed on the Small Generating Facility alone.[364] LES asserts that the Interconnection Customer should not be required to interconnect at a substation when transmission or distribution lines are closer. Some parties request that the Commission offer the Interconnection Customer a mechanism to resolve disputes over required upgrades.[365] VSI proposes new language for the Facilities Study Agreement section 10.0 that would allow for an expedited review by the public utility regulatory authority having jurisdiction over the upgrade costs at issue.[366] LES argues that the Commission needs to provide a remedy for promptly and efficiently resolving disputes over the minimum upgrades and interconnection facilities needed to interconnect a Small Generating Facility. For example, LES states that if a Transmission Provider mischaracterizes a network upgrade or interconnection facility in order to avoid paying that cost itself, the small generator must have recourse available.[367] Otherwise, Transmission

[348] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 41.

[349] *Id.* P 43.

[350] AWEA, CEIP, Clean Coalition, CREA, DCOPC, Duke Energy, ELCON, FCHEA, IECA, ITC, NRG, Public Interest Organizations, and SEIA.

[351] SEIA at 15.

[352] CREA at 3.

[353] FCHEA at 1.

[354] MISO at 9–10.

[355] CAISO at 6; ISO–NE at 17; and MISO at 9–10.

[356] CAISO at 8.

[357] CAISO at 6.

[358] NYISO & NYTO at 22.

[359] *Id.*

[360] *Id.*

[361] *Id.*

[362] VSI at 4–5.

[363] LES at 4 and VSI at 4–5.

[364] LES at 4.

[365] Max Hensley at 1; LES at 4; Lucia Villaran at 2; and VSI at 4–5.

[366] VSI at 6.

[367] LES at 4.

Providers may claim to have final discretion over what interconnection facilities are required to be built.[368]

197. IECA recommends that the Commission monitor and measure the effectiveness and efficiency of its SGIP. IECA states that the Commission should assure that the SGIP and LGIP do not have the unintended consequence of providing opportunities for Transmission Providers to easily stop SGIP or LGIP applications with endless evaluation processes of ''meaningful dialogue,'' which the review of required upgrades is intended to promote.[369] IECA asserts that the Commission should initiate a process that routinely gathers key information to monitor the utilization and outcomes of the SGIP and should track, characterize, tabulate, and annually report all resolved and unresolved interconnection applications under its SGIP for the purpose of identifying and potentially removing interconnection barriers.[370]

198. Clean Coalition recommends that the Commission allow the Interconnection Customer to use third party contractors to perform the required upgrades, as is allowed under Rule 21, at the Interconnection Customer's option.[371] Clean Coalition asserts that this will allow competition to reduce upgrade costs and ensure that Transmission Providers keep upgrade costs low.[372]

199. NRECA, EEI & APPA, however, state that a developer's use of a third party to provide input on the process relating to upgrade requirements, alternatives and related issues can further complicate the process.[373] They state that formalizing these practices will do more harm than good because adding steps to the process can potentially delay and adversely impact other projects.[374] NRECA, EEI & APPA also assert that third-party contractors performing upgrades at the Interconnection Customer's option raises safety, liability, access, and reliability concerns.[375] The commenters suggest that the Commission only permit Interconnection Customers to use third-party contractors to perform upgrades in cases where the Transmission Provider agrees.[376]

200. NRECA, EEI & APPA urge the Commission to ensure that utilities are properly compensated for the time and expenses associated with documenting the decision-making process to determine required upgrades.[377] NRECA, EEI & APPA assert that in order to balance the Interconnection Customer's desire to have additional information on required upgrades with the added burden on Transmission Providers of preparing such information, the Commission must clearly state that the utility can collect its estimated costs before any additional study work is done.[378]

201. SEIA opposes charging Interconnection Customers additional fees associated with documenting the decision-making process of the facilities study.[379] SEIA asserts that these additional costs are unwarranted because the LGIP currently requires Interconnection Customers to pay the Transmission Provider's actual costs of completing the facilities study and the SGIP should be consistent with the LGIP.[380] Additionally, SEIA claims that compensating Transmission Providers for meetings and data gathering would constitute an ''unlimited and undefined blank check'' to recover costs beyond those actually incurred and create unnecessary uncertainty for developers.[381] NRECA, EEI & APPA state that they are not requesting a blank check and assert that Transmission Providers should be permitted to recover all prudently incurred costs resulting from such documentation requirements.[382]

202. Finally, NYISO & NYTO assert that the Commission should include the proposed revisions to the Facilities Study Agreement allowing the Interconnection Customer the opportunity to review and comment upon the upgrades the Transmission Provider finds necessary for interconnection in section 3.5 of the *pro forma* SGIP to be consistent with the similar procedures for Large Generating Facilities in sections 8.3 and 8.4 of the LGIP.[383]

3. Commission Determination

203. The Commission affirms its proposal to allow Interconnection Customers to provide written comments on the required upgrades in the facilities study. The Commission believes the adoption of this proposal will allow Interconnection Customers to have a meaningful opportunity to review any upgrades associated with an interconnection request and engage in a dialogue with the Transmission Provider. In addition, allowing Interconnection Customers the opportunity to provide written comments on required upgrades helps to ensure interconnection costs are just and reasonable.

204. The Commission agrees with SEIA that the Interconnection Customer is entitled to view the facilities study supporting documentation because it is funding the study. The Commission is not persuaded by APPA, EEI & NRECA's claim that documenting the facilities study will be unduly burdensome because the LGIP has a similar requirement. However, the Commission affirms that Transmission Providers are entitled to collect all just and reasonable costs associated with producing the facilities study, including any reasonable documentation costs.

205. We note that Transmission Providers that incorporate, or propose to incorporate, comments through a different process may submit compliance filings demonstrating that the process is consistent with or superior to the requirements contained herein or meets another standard allowed for in this Final Rule.[384]

206. Various parties propose a regulatory review of required upgrades when there is a dispute. The Commission rejects this request because the parties have the option of utilizing the SGIA dispute resolution procedures outlined in section 4.2 of the SGIP to resolve such disputes. In addition, in the event the dispute cannot be resolved, the Interconnection Customer may request that the Transmission Provider file the unexecuted interconnection agreement with the Commission.[385]

207. The Commission declines to adopt NYISO & NYTO's proposal to affirm that Transmission Providers are not required to perform additional analysis or make modifications based on comments unless the Interconnection Customer agrees to pay for the additional studies. While the Commission does not require Transmission Providers to modify the facilities study after receiving Interconnection Customer comments, the Commission encourages Transmission Providers to consider these comments when finalizing the facilities study. Further, the Commission reaffirms that the

[368] *Id.* at 4.

[369] IECA at 7.

[370] *Id.*

[371] Clean Coalition at 8.

[372] *Id.*

[373] NRECA, EEI & APPA at 27–28.

[374] *Id.* at 28.

[375] NRECA, EEI & APPA Reply Comments at 11–12.

[376] *Id.* at 12.

[377] NRECA, EEI & APPA at 8.

[378] *Id.*

[379] SEIA Reply Comments at 8.

[380] *Id.*

[381] *Id.*

[382] NRECA, EEI & APPA Reply Comments at 13.

[383] NYISO & NYTO at 22–23.

[384] *See infra* section V.

[385] *See* SGIP section 4.8 of Appendix C attached hereto.

Transmission Provider should make the final decision on upgrades required for interconnection because the Transmission Provider is ultimately responsible for the safety and reliability of its system.[386] For the same reason, the Commission finds that third-party contractors may not perform any interconnection-associated network upgrades without Transmission Provider consent.

208. The Commission's experience with the LGIP comment process does not suggest that allowing comments prevents new interconnections, which was a concern raised by IECA. Therefore, the Commission finds it unnecessary to formally monitor the number of Small Generating Facility interconnections at this time.[387] If an Interconnection Customer believes it is being treated in an unduly discriminatory manner, it may file a complaint with the Commission.

209. Finally, the Commission disagrees with NYISO & NYTO that the provisions related to Interconnection Customers providing written comments on required upgrades should be included in section 3.5 of the SGIP to be consistent with the LGIP. In the SGIP, the details regarding the facilities study report are found in the SGIA, so the Commission finds it appropriate to add the provisions related to providing written comments on required upgrades to the SGIA as proposed.

E. Revision to SGIA Section 1.5.4 Regarding Over and Under-Frequency Events

1. Commission Proposal

210. In the NOPR, the Commission proposed revisions to section 1.5.4 of the SGIA to address a reliability concern related to automatic disconnection of the Small Generating Facility during over- and under-frequency events that could become a matter of concern at high penetrations of PV resources. The proposed revisions to section 1.5.4 would require the Interconnection Customer to design, install, maintain, and operate its Small Generating Facility, in accordance with the latest version of the applicable standards (e.g., IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems), to prevent automatic disconnection during over- and under-frequency events and to ensure that rates remain just and reasonable.[388]

2. Comments

211. ISO–NE supports the Commission's proposal to mitigate the potential frequency problems and requests that the Commission revise the proposed modifications to include a voltage ride-through provision as well.[389] CAISO supports the proposed reform but urges the Commission to coordinate its proposed reform with the outcome of the CPUC's Rule 21 proceedings.[390]

212. CPUC states that it is currently developing technical standards to address voltage, frequency and other issues arising from Small Generating Facilities and is unable to provide comments until those standards are finalized.[391] CPUC notes that it is focusing on ''smart inverters'' to mitigate the voltage, frequency and other impacts of Small Generating Facilities.[392]

213. ComRent suggests that the Final Rule recognize the upcoming changes to IEEE 1547, including more interactive control of distributed resources by the electric power system operator and test requirements for interconnection.[393] ComRent encourages the Commission to reference the current version of the standards and acknowledge that the requirements may evolve through the consensus standards making process. ComRent also notes that the capability to provide documented tests for interconnection and impact to a wide range of variables are available today in the size range being discussed in this rulemaking.[394]

214. AWEA expresses concern that a requirement to comply with IEEE 1547 could actually be counterproductive for making the power system more resilient to over- or under-frequency events.[395] AWEA argues that IEEE 1547 as currently drafted requires distributed generation up to 10 MW to remain online only during extremely small frequency deviations, and requires them to disconnect during moderate frequency deviations.[396] AWEA asserts that this requirement counters the Commission's stated goal of preventing automatic disconnection during an over- or under-frequency event.[397] In supplemental comments, AWEA notes that pending revisions to IEEE 1547 no longer prohibit voltage and frequency ride-through for distributed generators.[398]

215. AWEA states that the Commission should convene a technical conference and pursue other efforts to ensure that IEEE and other entities are working towards a standard that will prevent automatic disconnection of new distributed generation during moderate over- and under-frequency events.[399] In addition, AWEA states that the Commission should clarify that, while the ride-through requirement for new generators may evolve as standards like IEEE 1547 evolve, the requirement for existing generators will be fixed at whatever standard was in place at the time the SGIA for that generator was implemented.[400]

216. The California Utilities assert that further exploration of this issue is needed before any rules are proposed.[401] The California Utilities assert that the Commission should consider the role of the smart inverter because it may provide the ability to address frequency and voltage ride-through and other benefits related to voltage control and reactive power support.[402]

217. NRECA, EEI & APPA assert that the proposed revisions to SGIA section 1.5.4 will require the Interconnection Customer to design, install, maintain and operate its Small Generating Facility in accordance with the latest version of the applicable North American Electric Reliability Corporation (NERC) reliability standards, unless the Transmission Provider has established different requirements that apply to all similarly situated generators in the control area on a comparable basis, to prevent automatic disconnection during an over- or under-frequency event.[403] NRECA, EEI &APPA suggest revising the proposed language in SGIA section 1.5.4 as follows:

1.4.1.2 ''. . . The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of (1) a disturbance of its Small Generating Facility adversely affecting or impairing the system or equipment of the Transmission Provider and any Affected Systems, and (2)

[386] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 27. We note that this decision by the Transmission Provider is ''final'' in the context of the dialogue between the Interconnection Customer and the Transmission Provider, but may be reviewed in some circumstances by the Commission (e.g., in response to a compliant that a Transmission Provider is requiring certain upgrades in an arbitrary or unduly discriminatory manner).

[387] We note that section 4.7 of the SGIP requires the retention of certain records for three years and provides that such records are subject to audit.

[388] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 46.

[389] ISO–NE at 20.

[390] CAISO at 8.

[391] CPUC at 7–8.

[392] *Id.* at 7.

[393] ComRent at 1.

[394] ComRent at 1.

[395] AWEA at 2.

[396] *Id.* at 5.

[397] *Id.*

[398] AWEA Supplemental Comments at 5.

[399] AWEA at 6.

[400] *Id.* at 7.

[401] California Utilities at 5.

[402] *Id.*

[403] NRECA, EEI & APPA at 28–29.

a disturbance of the system or equipment of the Transmission Provider or any Affected System causing off-normal frequency deviations unless the Transmission Provider has established different requirements that apply to all similarly situated generators in the control area on a comparable basis and resulting in a common mode disconnection of its Small Generating Facility.'' [404]

218. NRECA, EEI & APPA also request that the following sentence be added to SGIA section 1.5.2 requiring the Small Generating Facility to permit equal current in each phase conductor: ''Voltage unbalance resulting from unbalanced currents shall not exceed 2% between phases and shall not cause objectionable effects upon or interfere with the operation of the interconnection to the [Transmission Provider's System]. This criterion shall be met with and without generation.'' [405]

219. NRECA, EEI & APPA state that the Commission should not reference or incorporate IEEE Standards 1547 or 1547.1 into the Final Rule because mandatory standards do not permit the flexibility needed to allow IEEE standards to evolve and will likely impede the current 1547 standard development process.[406] They also assert that references to standards can lead to conflicting requirements if those standards are subsequently updated.[407] Citing Commission precedent, NRECA, EEI & APPA state that in the past, the Commission has declined to use rulemaking proceedings to make voluntary IEEE standards mandatory.[408]

3. *Commission Determination*

220. The Commission declines to adopt the NOPR proposal to revise to section 1.5.4 of the SGIA, or any of the revisions proposed by commenters, at this time. Section 1.5.4 of the *pro forma* SGIA adopted in Order No. 2006 already requires an Interconnection Customer to ''construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards.'' Based on the comments received, the Commission does not see a need to change section 1.5.4 of the SGIA at this time. As NRECA, EEI & APPA note, these standards may be revised as systems evolve. The Commission recognizes that IEEE is currently in the process of revising the requirements under IEEE Standard 1547a [409] for frequency ride-through, voltage ride-through, and voltage regulation. IEEE standards are reconsidered every 10 years, and at the end of the 10-year period, the standard may be either revised or withdrawn.[410] The revision of the IEEE Standard 1547 will begin in early 2014, which will allow another opportunity to either correct or address outdated requirements in the standard. We encourage Transmission Providers and NERC to participate in the IEEE standards development process to provide input on the effects of the growing penetration of distributed generation on the bulk-power system. The Commission will continue to follow this process and may revise the *pro forma* SGIA as it relates to IEEE Standard 1547 in the future, if necessary.

221. Finally, the Commission disagrees with NRECA, EEI & APPA's comment that section 1.5.2 requires the Interconnection Customer to design, install, maintain, and operate its Small Generating Facility in accordance with the latest version of the applicable NERC reliability standards. The *pro forma* SGIA is applicable to generators no larger than 20 MW (approximately 20 megavolt amperes (MVA)). The NERC reliability standards are generally applicable to generators greater than 20 MVA.[411] Therefore, NERC reliability standards would generally not apply to Small Generating Facilities executing the SGIA. However, the Commission notes that IEEE Standard 1547 applies to generators with a capacity of 10 MVA or less. The Commission encourages IEEE to formulate interconnection standards for generators between 10 and 20 MVA.

F. Interconnection of Storage Devices

1. Commission Proposal

222. In the NOPR, the Commission announced that it would hold a workshop before the end of the comment period that would include the following topic: ''Whether storage devices could fall within the definition of Small Generating Facility included in Attachment 1 to the SGIP and Attachment 1 to the SGIA as devices that produce electricity.'' The March 27, 2013 workshop included a roundtable discussion on the interconnection of storage devices. The Commission requested comments on issues raised at the workshop in addition to comments on the NOPR.[412]

2. Comments

223. CREA supports including storage devices within the definition of Small Generating Facility.[413] CREA opines that expanding the definition to include storage will incentivize small generators to keep abreast of future innovations in storage technology.[414] CAISO believes the existing definition is sufficiently broad to encompass a storage device and therefore apply the SGIP to such a facility if it is less than 20 MW.[415]

224. The California Utilities believe that further exploration of this issue is needed before any rules are proposed and note that interconnection of storage devices will be discussed during Phase II of California's Rule 21 proceeding.[416]

225. ESA states that the Commission should define a Small Generating Facility as ''a device used for the production and/or storage for later injection of electricity having a maximum output of no more than 20 MW.'' [417] ESA states that the Commission should measure the capacity of a storage resource based on the maximum quantity that the resource can inject to the grid to be comparable to other small generators for the purposes of determining if the storage device is a Small Generator or qualifying it for the Fast Track Process.[418]

226. ESA also recommends that the Commission clarify how to measure the size of interconnections that are combining renewable resources with storage devices.[419] ESA recommends that interconnection size be measured by the maximum intended injection of the combined resource.[420] ESA states that its recommendations are entirely consistent with the interpretation to date of the SGIP for storage projects, and that it merely wants the Commission to confirm existing practice.[421]

[404] *Id.,* Appendix B at 4.

[405] *Id.*

[406] NRECA, EEI & APPA Reply Comments at 17.

[407] *Id.*

[408] *Id.* (citing *Trans. Relay Loadability Reliability Std.,* Order No. 733, 130 FERC ¶ 61,221, at P 207 (2010)).

[409] IEEE Standard 1547a is an amendment to IEEE Standard 1547 to establish updates to voltage regulation, as well as response to abnormal voltage and frequency conditions.

[410] *See* ''Revising Standards,'' *available at http://standards.ieee.org/develop/revisestds.html.*

[411] NERC Statement of Compliance Registry Criteria at p. 9, *available at http://www.nerc.com/files/Appendix_5B_RegistrationCriteria_20120131.pdf.*

[412] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 49.

[413] CREA at 3.

[414] *Id.*

[415] CAISO at 9.

[416] California Utilities at 5. Also, *see supra* note 231.

[417] ESA at 6.

[418] *Id.* at 5.

[419] *Id.*

[420] *Id.* 6.

[421] *Id.* at 5.

3. Commission Determination

227. The Commission finds, based on the comments received, that it is appropriate to adopt certain revisions to the *pro forma* SGIP to explicitly account for the interconnection of storage devices in order to ensure that storage devices are interconnected in a just and reasonable and not unduly discriminatory manner. The Commission acknowledges that the interconnection of storage devices will be discussed in the ongoing Rule 21 proceeding as the California Utilities point out in their comments.[422] As more experience is gained with the interconnection of storage devices and as the issue is explored further in other proceedings, such as the Rule 21 proceeding, the Commission may adopt further revisions to the *pro forma* SGIP and SGIA associated with the interconnection of storage devices.

228. The Commission agrees with CAISO that the definition of Small Generating Facility is broad enough to include storage devices. However, the Commission also agrees with ESA and CREA that, in order to improve the transparency of the SGIP, the definition of Small Generating Facility in the *pro forma* SGIP and SGIA should be clarified to explicitly include storage devices. Accordingly, the Commission revises the definition of Small Generating Facility in Attachment 1 to the SGIP and Attachment 1 to the SGIA as follows: ''The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.''

229. The Commission agrees with ESA that when determining whether a storage device may interconnect under the SGIP and/or whether it qualifies for the Fast Track Process, the Transmission Provider should generally assume that the capacity of the storage device is equal to the maximum capacity that the particular device is capable of injecting into the Transmission Provider's system (e.g., a storage device capable of injecting 500 kW into the grid and absorbing 500 kW from the grid would be evaluated at 500 kW for the purpose of determining if it is a Small Generating Facility or whether it qualifies for the Fast Track Process). Thus, the Commission revises SGIP section 4.10.3 to clarify that the term ''capacity'' of the Small Generating Facility in the SGIP refers to the maximum capacity that a device is capable of injecting into the Transmission Provider's system. When interconnecting such a storage device, the revisions to SGIP section 4.10.3 adopted herein do not preclude a Transmission Provider from studying the effect on its system of the absorption of energy by the storage device and making determinations based on the outcome of these studies.

230. To address ESA's comment related to combining generation resources with storage resources (e.g., a storage facility operating to firm a variable energy resource), the Commission further revises SGIP section 4.10.3. Under section 4.10.3 adopted herein, the Transmission Provider is to measure the capacity of a Small Generating Facility based on the capacity specified in the interconnection request, which may be less than the maximum capacity that a device is capable of injecting into the Transmission Provider's system, provided that the Transmission Provider agrees, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to limit the maximum capacity that its facility is capable of injecting into the Transmission Provider's system will not adversely affect the safety and reliability of the Transmission Provider's system. For example, an Interconnection Customer with a combined resource may propose a control system, power relays, or both for the purpose of limiting its maximum injection amount into the Transmission Provider's system.

231. The Commission notes that in Order No. 2006 it considered evaluating Small Generating Facilities based on less than their maximum rated capacity, but determined that this would not ensure that proper protective equipment is designed and installed and that the safety and reliability of the Transmission Provider's system could be maintained.[423] However, as discussed above, the energy industry has changed since Order No. 2006 was issued.[424] The use of storage in combination with other resources was not contemplated in Order No. 2006. In order to balance the needs of Small Generating Facilities and Transmission Providers, the Commission clarifies that section 4.10.3 adopted herein applies only to the determination of whether a resource is a Small Generating Facility to be evaluated under the SGIP rather than the LGIP, or if it qualifies for the Fast Track Process. In the Study Process, the Transmission Provider has the discretion to study the combined resource using the maximum capacity the Small Generating Facility is capable of injecting into the Transmission Provider's system and require proper protective equipment to be designed and installed so that the safety and reliability of the Transmission Provider's system is maintained. Similarly, in the Fast Track Process, the Transmission Provider may apply the Fast Track screens or the supplemental review screens using the maximum capacity the Small Generating Facility is capable of injecting into the Transmission Provider's system in a manner that ensures that the safety and reliability of its system is maintained.

G. Other Issues

1. Network Resource Interconnection Service

a. Commission Proposal

232. The Commission proposed to revise section 1.1.1 of the *pro forma* SGIP to require Interconnection Customers wishing to interconnect its Small Generating Facility using Network Resource Interconnection Service to do so under the LGIP and execute the LGIA. The Commission explained that this requirement was included in Order No. 2006[425] but was not made clear in the *pro forma* SGIP. To facilitate this clarification, the Commission also proposed to add the definitions of Network Resource and Network Resource Interconnection Service to Attachment 1, Glossary of Terms, of the *pro forma* SGIP.[426]

b. Comments

233. MISO states that its generator interconnection procedures and agreement are the result of a merger of its LGIP/LGIA and SGIP/SGIA in 2008. Because it does not differentiate between small and large interconnection requests, MISO states that the proposed revisions to section 1.1.1 of the *pro forma* SGIP would likely not apply to MISO.[427] MISO further asserts that its generator interconnection procedures already provide comparable definitions for ''Network Resource'' and ''Network Resource Interconnection Service.''[428]

234. NYISO & NYTO state this proposed revision could undermine the requirements in Attachment Z of the NYISO OATT that permit a Small Generating Facility to elect Capacity Resource Interconnection Service under

[422] California Utilities at 5.

[423] *See* Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at PP 79–86.

[424] *See supra* PP 0–0.

[425] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 140.

[426] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 45.

[427] MISO at 10.

[428] *Id.* at 10–11.

NYISO's SGIP and to execute an SGIA.[429] NYISO & NYTO assert that making Small Generating Facilities subject to the LGIP and requiring an LGIA would greatly increase the time and expense of interconnecting such projects. Therefore, NYISO & NYTO ask the Commission to clarify that the proposed revisions will not disturb these existing procedures.[430]

c. Commission Determination

235. The Commission adopts the revisions as proposed in the NOPR. As the Commission noted in the NOPR, the revision is meant to clarify in the *pro forma* SGIP an Order No. 2006 requirement rather than implement a new requirement.

236. Our intent is not to require revisions to interconnection procedures that have previously been found to be consistent with or superior to the *pro forma* SGIP and SGIA with regard to this Order No. 2006 requirement or permissible under the independent entity variation standard. In cases where provisions in Transmission Providers' existing interconnection procedures have been found by the Commission to be consistent with or superior to the *pro forma* SGIP and SGIA originally adopted under Order No. 2006 or permissible under the independent entity variation standard would be modified by the Final Rule, public utility Transmission Providers must either comply with the Final Rule or demonstrate that these previously approved variations meet the standard under which they are filed.[431]

2. Hosting Capacity

a. Comments

237. Pepco offers its ''hosting capacity'' process as an alternative approach to the interconnection procedures in the NOPR and claims that it is superior to the proposed pre-application report and Fast Track screens.[432] According to Pepco, its hosting capacity approach calculates the maximum aggregate generating capacity that a distribution circuit can accommodate at a proposed Point of Interconnection without requiring the construction of facilities by the Transmission Provider on its own system and while maintaining the safety, reliability and power quality of the distribution circuit.[433] Pepco states that hosting capacity is determined by applying the screens set forth in section 2.4.1.1 to 2.4.1.3 of the SGIP and will describe the amount of additional generating capacity a distribution circuit can accommodate above what has already been approved or queued for interconnection without requiring the construction of facilities by the Transmission Provider.[434]

238. Pepco states that it has successfully interconnected over 7,700 PV systems by using load flow tools to determine a maximum allowable hosting capacity at a given Point of Interconnection on its transmission and distribution systems.[435] Pepco asserts that load flow tools have allowed PV interconnections on many circuits that would otherwise not be available to new generation because they would violate a number of existing technical screens under the current SGIP, including the 15 Percent Screen.[436]

239. IREC, Sandia and SEIA support allowing Transmission Providers to use load-flow tools to determine the hosting capacity at a particular Point of Interconnection in both the pre-application report and the Fast Track process, and encourage the Commission to include language related to hosting capacity in the Final Rule and in the *pro forma* SGIP.[437] IREC states that hosting capacity would replace the total, allocated and available capacity in the pre-application report because these items are no longer valuable once the hosting capacity is known.[438] IREC notes that the SGIP hosting capacity provisions it proposes with Pepco, NREL, and Sandia would not be mandatory for Transmission Providers, but would allow for the use of hosting capacity where the capability exists.[439]

240. IREC supports allowing Transmission Providers to elect not to use the Fast Track screens when they can provide hosting capacity, but would require them to comply with the 15 Percent Screen at a minimum.[440] IREC states that if the Transmission Provider determines that using hosting capacity limits its ability to connect a proposed generator without further study, the Transmission Provider would be required to provide the Interconnection Customer with an explanation of the power flow, criteria violations, and/or queued projects that limit the hosting capacity.[441] IREC believes the revisions related to hosting capacity will significantly improve the Fast Track Process for both generators and Transmission Providers, and may allow for larger generators or greater penetrations of distributed generation to interconnect using the Fast Track Process.[442] Further, IREC supports incorporating the hosting capacity provisions into the SGIP rather than requiring Transmission Providers to seek modifications to the *pro forma* SGIP.[443]

241. NREL supports the use of hosting capacity as long as Transmission Providers are transparent regarding how hosting capacity is determined.[444] VSI also supports IREC and Pepco's hosting capacity proposal.[445] VSI states that the duration of the Study Process would decrease and existing equipment would be better optimized if all Transmission Providers had the capability to determine their hosting capacity in advance of the pre-application report.[446]

242. Sandia supports the use of dynamic load flow analysis to determine the hosting capacity of a circuit, as it is the most comprehensive and accurate way to determine the deployment level of distributed generation that can be accommodated on a distribution circuit without system upgrades.[447]

b. Commission Determination

243. The Commission encourages Transmission Providers to develop innovative and transparent interconnection processes that provide valuable information to Interconnection Customers. However, the Commission declines to include hosting capacity in the SGIP at this time because the record does not contain a sufficient discussion of the proposal. Transmission Providers wishing to utilize hosting capacity as part of their interconnection process may propose such procedures in their compliance filings for this Final Rule. Similar to other filings that do not conform with the *pro forma* SGIP and SGIA adopted under this Final Rule, the Commission will consider whether such procedures meet the compliance standard under which the filing was made.[448]

[429] NYISO & NYTO at 23.

[430] *Id.*

[431] See *infra* P 0.

[432] Pepco at 4.

[433] Pepco, Attachment 1.

[434] *Id.* (stating that its hosting capacity considers queued capacity for which an interconnection agreement has not been issued).

[435] *Id.* at 4.

[436] *Id.*

[437] IREC at 8; Sandia at 3; and SEIA at 11.

[438] IREC at 11.

[439] *Id.* at 8, 11.

[440] *Id.* at 16.

[441] *Id.*

[442] *Id.* at 8, 16.

[443] *Id.* at 16.

[444] NREL at 3.

[445] VSI at 2.

[446] *Id.*

[447] Sandia at 3.

[448] *See infra* section V for a discussion of compliance with this Final Rule.

3. Jurisdiction

a. Comments

244. NRECA, EEI & APPA assert that the NOPR incorrectly states that ''[t]he *pro forma* SGIP and SGIA are used by a public utility to interconnect a Small Generating Facility with the utility's transmission or with its *jurisdictional distribution facilities* for the purpose of selling electric energy at wholesale in interstate commerce.'' [449] They state that, as explained in Order No. 2003–C, the Commission's authority ''is limited to the wholesale transaction'' and ''it may not regulate the 'local distribution' facility itself, which remains state-jurisdictional.'' [450] NRECA, EEI & APPA therefore state that the Commission was incorrect in characterizing distribution facilities as ''[FERC] jurisdictional.'' They ask that the Commission correct this improper characterization.

245. NYISO & NYTO similarly ask the Commission to clarify that the term ''Distribution System'' as proposed in sections 1.1.1, 3.1 and 2.1 of the SGIP is limited to distribution facilities that are subject to the Commission's jurisdiction.[451]

b. Commission Determination

246. The Commission clarifies that the scope of its jurisdiction in this proceeding with respect to distribution facilities is identical to the jurisdiction previously asserted and as described in Order Nos. 888 [452] and 2003. Just as the Commission stated in Order No. 2003–A:

> There is no intent to expand the jurisdiction of the Commission in any way; if a facility is not already subject to Commission jurisdiction at the time interconnection is requested, the Final Rule will not apply. Thus, only facilities that already are subject to the Transmission Provider's OATT are covered by this rule. The Commission is not encroaching on the States' jurisdiction and is not improperly asserting jurisdiction over ''local distribution'' facilities.[453]

247. In response to NYISO & NYTO's comment, the Commission clarifies that the term ''Distribution System'' as used in this Final Rule is limited to distribution facilities that are subject to the Commission's jurisdiction.

248. In Order No. 2006, the Commission stated that the regulations promulgated under Order No. 2006 applied to interconnections to facilities that are already subject to a Commission-jurisdictional OATT at the time the interconnection request is made and that will be used for purposes of jurisdictional wholesale sales.[454] In Order No. 2003–C, however, the Commission clarified that, ''while the Commission may regulate the entire transmission component * * * of the wholesale transaction—whether the facilities used to transmit are labeled 'transmission' or 'local distribution'—it may not regulate the 'local distribution' facility itself, which remains state-jurisdictional.'' [455] The Commission clarifies that its jurisdiction under this Final Rule does not extend to local distribution facilities.

4. Miscellaneous

a. Commission Proposal

249. In addition to the proposed reforms and clarifications described above, the Commission proposed to correct section 3.3.5 of the *pro forma* SGIA. Specifically, we proposed to replace the first word of this section (''This'') with ''The.''

b. Comments

250. Several comments did not fit neatly within the topics discussed in the NOPR. FCHEA and CEP support increasing the project size threshold for requiring telemetry equipment to 5 MW because this equipment can add significant financial burden to distributed generation projects.[456] FCHEA and CEP state that the Commission should strongly encourage the states to match the Commission threshold in state interconnection procedures to avoid discouraging development of distributed generation projects.[457] CEP also recommends several changes to net metering and demand charges associated with distributed generation.[458]

251. ELCON and IECA submitted comments in support of advancing combined heat and power (CHP) interconnections.[459] ELCON claims that various barriers to the development of large CHP generation currently exist and urges the Commission to initiate a Notice of Inquiry to investigate the issues.[460] IECA states that the Commission should establish longer-term capacity payment mechanisms to encourage capital formation for manufacturer CHP and waste heat recovery investments, such as a 15- to 20-year term capacity payment.[461]

252. Bonneville recommends that, to prevent an Affected System [462] from having to construct upgrades or new facilities in response to an interconnection, the Commission should revise section 2.2.1.10 of the SGIP to read ''No construction of facilities by the Transmission Provider on its own system, nor construction of any facilities on any Affected System, shall be required to accommodate the Small Generating Facility.'' [463]

253. NREL states that it has analyzed PV systems integrated onto secondary network distribution systems and has found that there are methods of increasing the amount of interconnected PV generation on a spot network without affecting reliability and power quality.[464] NREL proposes adding language to the Secondary Network Distribution System screen.[465]

254. NRECA, EEI & APPA suggest adjusting the feasibility study deposit of $1,000 and the Fast Track processing fee of $500 annually based on the Consumer Price Index.[466] The commenters also suggest changing the record retention requirement in SGIP section 4.7 from three years to five years.[467] NRECA, EEI & APPA also suggest two changes to the Fast Track screens in section 2.2.1: (1) Adding language to section 2.2.1.2 for areas bounded by a voltage regulation zone of a distribution line or a power transformer; and (2) revising the 10 MW aggregate interconnected generation threshold in section 2.2.1.9 for areas with known or posted transient stability limitations to accommodate ISOs and

[449] NRECA, EEI & APPA at 29 (quoting the NOPR, FERC Stats. & Regs. ¶ 32, 6a7 at P1, n. 4) (emphasis added).

[450] *Id.* at 29–30 (referencing Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 at P 53).

[451] NYISO & NYTO at 24.

[452] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[453] Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160 at P 700.

[454] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at PP 7–8.

[455] Order No. 2003, FERC Stats. & Regs. ¶ 31,146.

[456] FCHEA at 1.

[457] *Id.* at 2.

[458] CEP at 2–3.

[459] ELCON at 4.

[460] *Id.* at 6–7 and IECA at 10.

[461] IECA at 10.

[462] *See supra* note 343.

[463] Bonneville at 3.

[464] NREL at 5.

[465] *Id.* NREL proposes adding the following to the Secondary Network Distribution System screen: ''or 25kVA less than the minimum daytime load of the network when the proposed Small Generating Facility is a PV system and will have minimum import relay and dynamically controlled inverter controls installed to prevent backfeed onto the secondary network.''

[466] NRECA, EEI & APPA, Appendix B at 3–4.

[467] *Id.* at 3.

RTOs that may have lower thresholds.[468]

255. Clean Coalition strongly urges the Commission to ensure that any SGIP reforms adopted in this Final Rule apply equally to grid operators using the SGIP and to those that have combined the SGIP and LGIP into a single generator interconnection procedure.[469]

256. UCS asks the Commission to ''assert an affirmative obligation'' that Transmission Providers integrate and use the voltage support capability provided by Small Generating Facilities.[470] UCS asserts that the Transmission Provider's failure to utilize the voltage control capability of Small Generating Facilities increases the interconnection costs because the Transmission Provider may require upgrades to provide voltage support rather than using the capability inherent in the proposed facility.[471]

c. Commission Determination

257. The Commission finds the following to be beyond the scope of this proceeding: (1) FCHEA and CEP's requests to increase the threshold for requiring telemetry equipment; (2) ELCON and IECA's recommendations regarding CHP; (3) CEP's recommendations with regard to net metering and demand charges associated with distributed generation; (4) NRECA, EEI & APPA's proposed changes to the Fast Track screens in SGIP section 2.2.1; (5) NRECA, EEI & APPA's proposal to change the record retention requirement in SGIP section 4.7 from three years to five years; (6) NREL's proposal to add language to the Secondary Network Distribution System screen in section 2.2.1.3 of the SGIP; and (7) UCS's request that the Commission require Transmission Providers to integrate and use the voltage support capability provided by Small Generating Facilities.

258. With regard to the impact of Fast Track screens on Affected Systems, section 4.9 of the SGIP already directs Transmission Providers to consider Affected Systems during the Fast Track screens when possible. Accordingly, the Commission finds that Bonneville's proposal to amend section 2.2.1.1 of the SGIP is unnecessary.

259. We decline to adjust the Fast Track processing fee for inflation because, as provided for in Order No. 2006, Transmission Providers may submit a filing under FPA section 205 if the fixed fees in the *pro forma* SGIP do not sufficiently recover their costs.[472] We also decline to adjust the feasibility study deposit for inflation because Transmission Providers collect actual costs for the feasibility study. If a Transmission Provider would like to increase this deposit, it may propose to do so in its compliance filing.[473]

260. Regarding Clean Coalition's request that the Commission require that the SGIP reforms adopted herein apply to public utility Transmission Providers that have combined their SGIP and LGIP into a single set of generator interconnection procedures, the Commission affirms that the reforms adopted herein apply to all Commission-jurisdictional SGIPs, including those that have been combined with LGIPs.

261. Finally, the Commission replaces the first word of section 3.3.5 of the *pro forma* SGIA (''This'') with ''The'' as proposed in the NOPR. The Commission also makes certain minor clarifying revisions to the flow chart in Appendix B to this Final Rule.

V. Compliance

A. Commission Proposal

262. In the NOPR, the Commission stated that each public utility Transmission Provider would be required to submit a compliance filing within six months of the effective date of the Final Rule revising its SGIP and SGIA or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements as set forth in the Final Rule.[474]

263. The Commission acknowledged that in some cases, public utility Transmission Providers may have provisions in their existing SGIPs and SGIAs that the Commission has deemed to be consistent with or superior to the *pro forma* SGIP and SGIA. The Commission indicated that where these provisions are modified by the Final Rule, public utility Transmission Providers must either comply with the Final Rule or demonstrate that these previously-approved variations continue to be consistent with or superior to the *pro forma* SGIP and SGIA as modified by the Final Rule.

264. The Commission also proposed that Transmission Providers that are not public utilities would have to adopt the requirements of the Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[475]

B. Comments

265. Several commenters urge the Commission to permit regional discretion and flexibility in the implementation of the SGIP.[476] Commenters urge the Commission to adopt a process that permits each region to develop and implement its own specific proposals to the problems identified by the Commission.[477] CAISO comments that the *pro forma* proposals may not in all instances allow ISOs and RTOs operating high-voltage transmission systems to streamline interconnections for Small Generating Facilities.[478]

266. NYISO & NYTO state that the Commission should direct each ISO/RTO to report on the status of its processing of small generator interconnection requests and to develop with its stakeholders and implement, where needed, regionally-tailored reforms to its SGIP.[479] Additionally, they state a regional approach would be consistent with the Commission's order concerning interconnection queuing practices where the Commission permitted each region the opportunity to propose its own solution to problems identified by the Commission with respect to queue management.[480] NYISO & NYTO request that the Commission clarify that, consistent with Order No. 2006, it will permit RTOs and ISOs to seek ''independent entity variations'' from any revisions to the *pro forma* SGIP to accommodate regional differences.[481]

267. CAISO states that it has commenced a stakeholder initiative to examine the need for interconnection procedure enhancements, including developing new Fast Track screens that are specific to the networked transmission system, and request that any action in this proceeding not preclude it from proposing enhancements to Fast Track screens consistent with the independent entity variation standard.[482]

[468] *Id.* at 2.

[469] Clean Coalition at 9.

[470] UCS at 22.

[471] *Id.* at 25.

[472] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 126.

[473] *See infra* section V.

[474] NOPR, FERC Stats. & Regs. ¶ 32,697 at P 50.

[475] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63.

[476] CAISO at 2; California Utilities at 4; ISO–NE at 2; IRC at 1; NYISO & NYTO at 2; and PJM at 4.

[477] CAISO at 2; IRC at 1; and NYISO & NYTO at 3.

[478] CAISO at 2.

[479] NYISO & NYTO at 3.

[480] NYISO & NYTO at 4 (referencing *Interconnection Queuing Practices,* Order on Technical Conference, 122 FERC ¶ 61,252 (March 20, 2008) (Queue Management Order)).

[481] *Id.* (referencing Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 549).

[482] CAISO at 7.

268. ISO–NE states that its *pro forma* SGIP has varied greatly from the Commission's *pro forma* SGIP since its implementation in 2006. Therefore ISO–NE requests regional flexibility to maintain the previously approved variations.[483] NARUC similarly emphasizes that ''proposals appropriate for one State or region of the country may not be appropriate, or permitted by State law or regulation, in other regions.'' [484] The California Utilities and NARUC also believe that the rules and procedures must be flexible enough to accommodate differences between the standards set by states and those set by the Commission in order for utilities to provide comparable service to generators interconnecting to their electric systems.[485]

C. Commission Determination

269. The Commission requires each public utility Transmission Provider to submit a compliance filing within six months of the effective date of this Final Rule revising its SGIP and SGIA or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth herein.

270. The Commission will consider requests for variations from this rule submitted on compliance on the same bases as the variations permitted for compliance with Order No. 2006.[486] Specifically, in cases where provisions in public utility Transmission Providers' existing SGIPs and SGIAs have been found by the Commission to be consistent with or superior to the *pro forma* SGIP and SGIA originally adopted under Order No. 2006 or permissible under the independent entity variation standard or regional reliability variation would be modified by the Final Rule, public utility Transmission Providers must either comply with the Final Rule or demonstrate that these previously-approved variations are consistent with or superior to the *pro forma* SGIP and SGIA as modified by the Final Rule or otherwise meet the requirements of this section.

271. Any non-public utility that has a safe harbor tariff may amend its small generator interconnection agreements and procedures so that they substantially conform or are superior to the *pro forma* SGIP and SGIA as revised by this Final Rule if it wishes to continue to qualify for safe harbor treatment.

272. As in Order Nos. 2003 and 2006, we will apply a regional differences rationale to accommodate variations from the Final Rule during compliance, but with certain restrictions. We conclude that a non-independent transmission provider (such as a Transmission Provider that owns generators or has Affiliates that own generators) and an RTO and ISO should be treated differently because an RTO or ISO does not raise the same level of concern regarding undue discrimination.[487] Accordingly, we will allow an RTO or ISO greater flexibility to propose variations from the Final Rule provisions, as further discussed below.

273. We will require, however, that non-independent transmission providers justify variations in non-price terms and conditions of the Final Rule using the approach taken in Order No. 888, which allows them to propose variations on compliance that are ''consistent with or superior to'' the OATT.[488] The Commission will consider two categories of variations from the Final Rule submitted by a non-independent Transmission Provider.[489] First, the Commission will consider ''regional reliability variations'' that track established reliability requirements (*i.e.,* requirements approved by the applicable NERC Regional Entity and the Commission).[490] Any request for a ''regional reliability variation'' must be supported by references to established reliability requirements, and the text of the reliability requirements must be provided in support of the variation. If the variation is for any other reason, the non-independent Transmission Provider must demonstrate that the variation is ''consistent with or superior to'' the Final Rule provision. Any request for application of this standard will be considered under Federal Power Act section 205 and must be supported by arguments explaining how each variation meets the standard.[491]

274. We will permit ISOs and RTOs to seek ''independent entity variations'' from any revisions to the *pro forma* SGIP and SGIA. This is a balanced approach that recognizes that an RTO or ISO has different operating characteristics depending on its size and location and is less likely to act in an unduly discriminatory manner than a Transmission Provider that is also a market participant. The RTO or ISO shall therefore have greater flexibility to customize its interconnection procedures and agreements to accommodate regional needs.[492]

275. Finally, for a non-independent Transmission Provider that belongs to an RTO or ISO, the RTO's or ISO's Commission-approved agreements and procedures are to govern interconnection with its members' facilities that are under the operational control of the RTO or ISO. An interconnection with a Commission jurisdictional facility that is owned by a non-independent Transmission Provider but is not under the operational control of the RTO or ISO is to be conducted according to the non-independent Transmission Provider's procedures and agreements. A non-independent Transmission Provider, even if it belongs to an RTO or ISO, is not eligible for ''independent entity variations'' for procedures and agreements applicable to interconnection with facilities that remain within its operational control (and, therefore, are subject to a tariff different than the RTO or ISO's OATT).[493]

276. Requests for regional reliability variations or independent entity variations are due on the effective date of this Final Rule. Requests for variations that are ''consistent with or superior to'' the *pro forma* OATT may be submitted on or after the effective date of the Final Rule.

VI. Information Collection Statement

277. The Office of Management and Budget (OMB) regulations require approval of certain information collection and data retention requirements imposed by agency rules.[494] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

278. The Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork

[483] ISO–NE at 19.

[484] NARUC at 4.

[485] California Utilities at 4.

[486] *See* Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 546–550.

[487] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 822.

[488] *Id.* at PP 822–827.

[489] *See* Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 546 (citing Order No. 2003 FERC Stats. & Regs. ¶ 31,146 at PP 824–825).

[490] *Id.*

[491] *Id.*

[492] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822–827.

[493] *See* Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 550.

[494] 5 CFR 1320.11(b).

Reduction Act of 1995.[495] In the NOPR, the Commission solicited comments on the need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing the respondents' burden, including the use of automated information techniques. The Commission included a table that listed the estimated public reporting burdens for the proposed reporting requirements, as well as a projection of the costs of compliance for the reporting requirements. The Commission also requested comments on three proposed revisions that were not included in the table: (1) The proposed revision of the 2 MW threshold for participation in the Fast Track Process (the Commission estimated that 100 Interconnection Customers annually may participate in the Fast Track Process rather than the Study Process under the NOPR); (2), the proposed revision to section 2.3.2 of the SGIP wherein the Transmission Provider would no longer be required to provide a good faith estimate of the cost of performing the supplemental review to the Interconnection Customer; and (3) the proposal to revise section 1.1.1 of the *pro forma* SGIP to require that if an Interconnection Customer wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it must do so under the LGIP and execute the LGIA.

279. The Commission did not receive any comments specifically addressing the burden estimates provided in the NOPR. However, the Commission has made changes to its proposal that are adopted in this Final Rule. First, the number of conforming changes to the SGIP and SGIA have increased (e.g., changes related to the interconnection of storage facilities and the pre-application report request form), so we have increased the burden estimate in the table below. Second, the addition of the pre-application report request form may increase the burden on Interconnection Customers requesting a pre-application report, so we have increased the burden estimate in the table. Third, we added two items to the pre-application report, so we have increased the burden estimate for Transmission Providers to prepare the pre-application report in the table below. Because we did not adopt the proposed revision to section 2.3.2 of the SGIP wherein the Transmission Provider would no longer be required to provide a good faith estimate of the cost of performing the supplemental review to the Interconnection Customer, we are not modifying the burden estimate for the supplemental review. Further, because we did not receive comments on the other proposed revisions discussed above that were not included in the table, we are not modifying the burden estimate to account for these revisions. The Commission believes that the revised burden estimates below are representative of the average burden on respondents.

Burden Estimate: The estimated public reporting burden and cost for the requirements contained in this Final Rule follow:

BILLING CODE 6717–01–P

[495] 44 U.S.C. 3507(d) (2012).

Data Collection FERC 516A (All changes under 18 CFR 35.28(f) (2013))	Number of Respondents [1]	Number of Responses[496] [2]	Hours per Response [3]	Total Annual Hours [1 X 2 X 3]
Conforming SGIP and SGIA changes to incorporate proposed revisions. First year only.	142 Transmission Providers	1	7	994
Pre-Application Report	800 Interconnection Customers[497]	1	1	800
Pre-Application Report	142 Transmission Providers	5.63	2.5	1,999
Supplemental Review[498]	500 Interconnection Customers	1	0.5	250
Supplemental Review	142 Transmission Providers	3.52	20	9,997
Review of Required Upgrades	250 Interconnection Customers	1	1	250
Review of Required Upgrades	142 Transmission Providers	1.76	2	500
First Year Total				14,790
Year Two and Ongoing Total				13,796

[496] The number of responses represents the average number of responses per respondent.

[497] We assume each request for a pre-application report corresponds with one Interconnection Customer.

[498] While this Final Rule adds a notification requirement if an Interconnection Customer fails any of the supplemental review screens, we believe that the burden is minimal and does not merit a change to the burden hours listed in the table.

BILLING CODE 0617–01–C

Cost to Comply: Total Annual Hours for Collection in initial year (14,790 hours) @ $75/hour[499] = $1,109,250.

Total Annual Hours for Collection in subsequent years (13,796 hours) @$ $75/hour = $1,034,700.

Title: FERC–516A, Standardization of Small Generator Interconnection Agreements and Procedures.

Action: Revision of Currently Approved Collection of Information.

OMB Control No. 1902–0203.

Respondents for this Rulemaking: Businesses or other for profit and/or not-for-profit institutions.

Frequency of Information: As indicated in the table.

Necessity of Information: The Commission is adopting these amendments to the *pro forma* SGIP and SGIA in order to more efficiently and cost-effectively interconnect generators no larger than 20 MW (small generators) to Commission-jurisdictional transmission systems. The purpose of this Final Rule is to revise the *pro forma* SGIP and SGIA so small generators can be reliably and efficiently integrated into the electric grid and to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory. This Final Rule seeks to achieve this goal by amending the *pro forma* SGIP and SGIA as described previously.

Internal Review: The Commission has reviewed the proposed changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

280. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], email: *DataClearance@ferc.gov*, Phone: (202) 502–8663, fax: (202) 273–0873.

281. Comments on the requirements of this rule can be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments to OMB should be submitted by email to: *oira_submission@omb.eop.gov.* Comments submitted to OMB should include Docket No. RM13–2–000 and OMB Control No. 1902–0203.

VII. Environmental Analysis

282. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[500] The Commission has categorically excluded certain actions from these requirements as not having a significant effect on the human environment.[501] The actions proposed here fall within categorical exclusions in the Commission's regulations for rules that are clarifying, corrective, or procedural, for information gathering, analysis, and dissemination, and for sales, exchange, and transportation of natural gas that requires no construction of facilities.[502] Therefore, an environmental assessment is unnecessary and has not been prepared as part of this Final Rule.

VIII. Regulatory Flexibility Act Analysis

283. The Regulatory Flexibility Act of 1980 (RFA)[503] generally requires a description and analysis of Final Rules that will have significant economic impact on a substantial number of small entities. The Commission estimates that the total number of Transmission Providers impacted by this Final Rule that are small entities is 11. The Commission estimates that the average total cost for each of these entities will be minimal, since most of the cost will be recovered from fees paid by Interconnection Customers. The estimated total number of Interconnection Customers that may be impacted by the requirements of this Final Rule is 800.[504] Of these, all are considered small. The Commission estimates that the total annual cost for each entity is $2,055.[505] The Commission does not consider this to be a significant economic impact. Further, the Commission expects that Interconnection Customers that are able to participate in the Fast Track Process rather than the Study Process will benefit from the proposed revisions to the *pro forma* SGIP.

284. Based on the above, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

IX. Document Availability

285. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

286. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

287. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

X. Effective Date and Congressional Notification

288. These regulations are effective February 3, 2014. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Act of 1996. The Commission will submit this

[499] This figure is the average of the salary plus benefits for an attorney, consultant (engineer), engineer, and administrative staff. The wages are derived from the Bureau of Labor and Statistics at *http://bls.gov/oes/current/naics3_221000.htm* and the benefits figure from *http://www.bls.gov/news.release/ecec.nr0.htm.*

[500] *Regulations Implementing the National Environmental Policy Act of 1969,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[501] 18 CFR 380.4 (2013).

[502] *See* 18 CFR 380.4(a)(2)(ii) (2013).

[503] 5 U.S.C. 601–612 (2012).

[504] We assume that 800 Commission-jurisdictional interconnection requests will be made annually. For the purposes of this Final Rule, each of these requests is assumed to be made by a separate Interconnection Customer.

[505] This number is derived by multiplying the hourly figure for Interconnection Customers in the Burden Estimate table (1,300) plus an additional 750 hours associated with reviewing the draft facilities study report by the cost per hour ($75); plus the $300 fee per pre-application report multiplied by 800 Interconnection Customers; plus the cost of the supplemental review (assumed to be $2,500) multiplied by 500 Interconnection Customers; all divided by the total number of Interconnection Customers (800). ((2,050 hrs * $75/hr) + ($300 * 800) + ($2,500 * 500))/800 = $2,055.

Final Rule to both houses of Congress and the Government Accountability Office.

The Commission orders:

By the Commission. Chairman Wellinghoff is not participating.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Note: Appendix A will not be published in the Code of Federal Regulations.

Appendix A: List of Short Names of Commenters on the Notice of Proposed Rulemaking

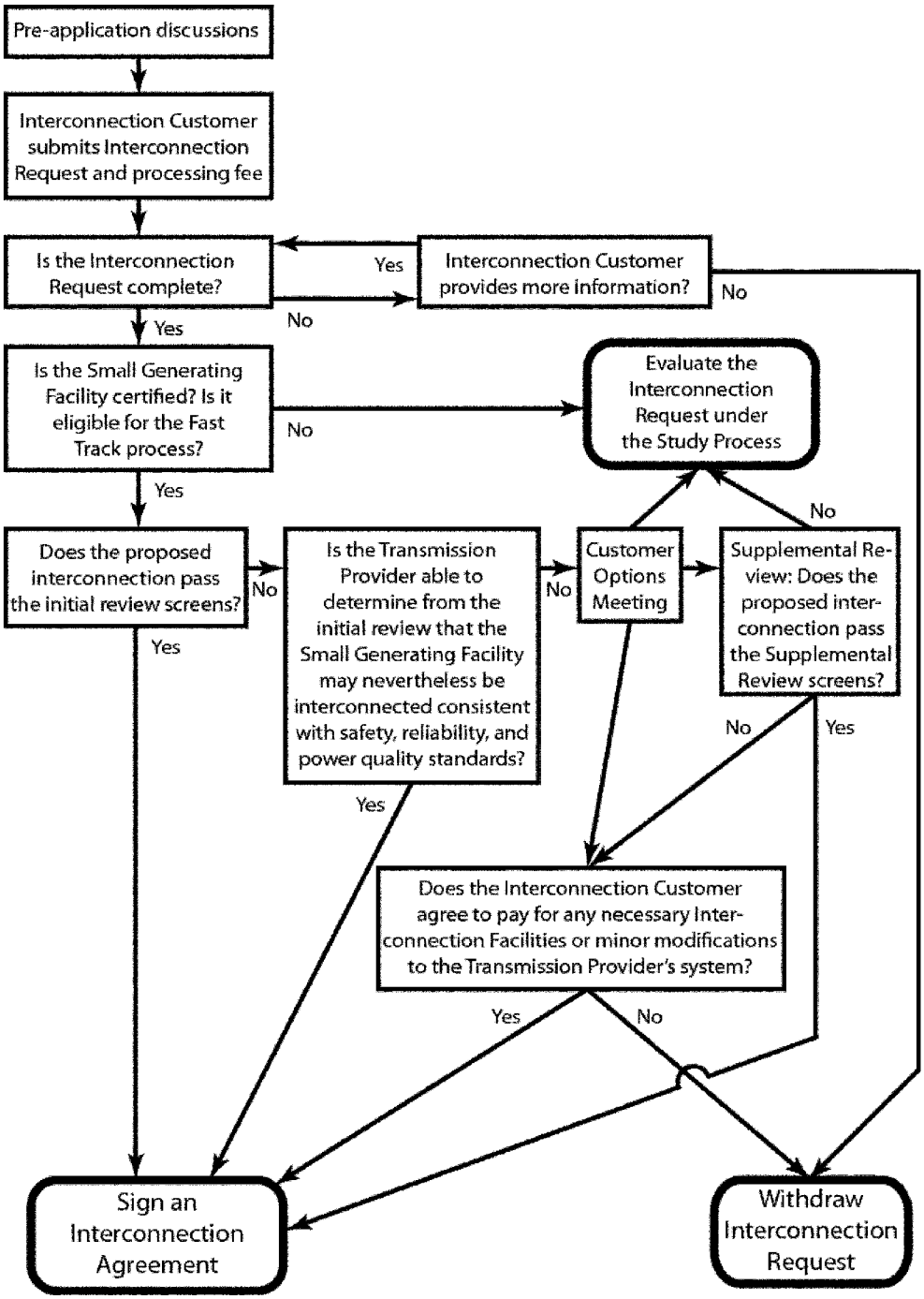
Short name or acronym	Commenter
AWEA	American Wind Energy Association.
Bonneville	Bonneville Power Administration.
CAISO	California Independent System Operator Corporation.
California Utilities	San Diego Gas & Electric Company, Southern California Edison Company and Pacific Gas and Electric Company.
CEP	ClearEdge Power.
Clean Coalition	Clean Coalition.
ComRent	ComRent International.
CPUC	California Public Utilities Commission.
CREA	Community Renewable Energy Association.
DCOPC	Office of the People's Counsel for the District of Columbia.
Duke Energy	Duke Energy Corporation.
Duquesne Light	Duquesne Light.
ELCON	Electricity Consumers Resource Council, American Chemistry Council, American Forest & Paper Association, American Iron and Steel Institute, CHP Association and Council of Industrial Boiler Owners.
ESA	Electricity Storage Association.
FCHEA	Fuel Cell & Hydrogen Energy Association.
IECA	Industrial Energy Consumers of America.
IREC	Interstate Renewable Energy Council.
IRC	ISO/RTO Council.
ISO–NE	ISO New England.
ITC	International Transmission Company.
LES	Landfill Energy Systems.
Lucia Villaran	Lucia Villaran.
Max Hensley	Max Hensley.
MISO	Midcontinent Independent System Operator.
NARUC	National Association of Regulatory Utility Commissioners.
NRECA, EEI & APPA	National Rural Electric Cooperative Association, Edison Electric Institute and American Public Power Association.
NREL	National Renewable Energy Laboratory.
NRG Companies	NRG Companies.
NYISO & NYTO	New York Independent System Operator and New York Transmission Owners.
Pepco	Pepco Holdings Inc., Atlantic City Electric Company, Delmarva Power & Light Company and Potomac Electric Power Company.
PJM	PJM Interconnection, LLC.
Public Interest Organizations	Center for Rural Affairs, Climate + Energy Project, Conservation Law Foundation, Energy Future Coalition, Environmental Defense Fund, Environmental Law & Policy Center, Environment Northeast, Fresh Energy, Great Plains Institute, National Audubon Society, Natural Resources Defense Council, Northwest Energy Coalition, Pace Energy and Climate Center, Piedmont Environmental Council, Sierra Club, Southern Alliance for Clean Energy, Southern Environmental Law Center, Sustainable FERC Project, Union of Concerned Scientists, Utah Clean Energy, Western Grid Group, Western Resource Advocates, The Wilderness Society and Wind on the Wires.
Sandia	Sandia National Laboratories.
SEIA	Solar Energy Industries Association.
UCS	Union of Concerned Scientists.
VSI	Vote Solar Initiative.

Note: Appendix B will not be published in the Code of Federal Regulations.

Appendix B

BILLING CODE 6717–01–P

Flow Chart for Interconnecting a Certified Small Generating Facility Using the "Fast Track Process"



Appendix C: Revisions to the *Pro Forma* SGIP

Small Generator Interconnection Procedures (SGIP)

(For Generating Facilities No Larger Than 20 MW)

TABLE OF CONTENTS

Page No.

Section 1. Application **1**

1.1 Applicability 1

1.2 Pre-Application 2

1.3 Interconnection Request 5

1.4 Modification of the Interconnection Request 6

1.5 Site Control 6

1.6 Queue Position 6

1.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP 7

Section 2. Fast Track Process **7**

2.1 Applicability 7

2.2 Initial Review 9

2.3 Customer Options Meeting 13

2.4 Supplemental Review 14

Section 3. Study Process **20**

3.1 Applicability 20

3.2 Scoping Meeting 20

3.3 Feasibility Study 21

3.4 System Impact Study 21

3.5 Facilities Study 23

Section 4. Provisions that Apply to All Interconnection Requests **24**

4.1 Reasonable Efforts 24

4.2 Disputes 24

4.3 Interconnection Metering 25

4.4 Commissioning 25

4.5. Confidentiality 25

4.6 Comparability 26

4.7 Record Retention 27

4.8 Interconnection Agreement 27
4.9 Coordination with Affected Systems 27
4.10 Capacity of the Small Generating Facility 28

Attachment 1 – Glossary of Terms
Attachment 2 – Small Generator Interconnection Request
Attachment 3 – Certification Codes and Standards
Attachment 4 – Certification of Small Generator Equipment Packages
Attachment 5 – Application, Procedures, and Terms and Conditions for Interconnecting a Certified Invertor-Based Small Generating Facility No Larger than 10 kW ("10 kW Inverter Process").
Attachment 6 – Feasibility Study Agreement
Attachment 7 – System Impact Study Agreement
Attachment 8 – Facilities Study Agreement

Section 1. Application

1.1 Applicability

1.1.1 A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) ~~no larger than 2 MW~~ to the Transmission Provider's Distribution System shall be evaluated under the section 2 Fast Track Process if the eligibility requirements of section 2.1 are met. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kilowatts (kW) shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility ~~larger than 2 MW but~~ no larger than 20 megawatts (MW) that does not meet the eligibility requirements of section 2.1, or ~~a Small Generating Facility that~~ does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the section 3 Study Process. If the Interconnection Customer wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it must do so under the Standard Large Generator Interconnection Procedures and execute the Standard Large Generator Interconnection Agreement.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures.

1.1.3 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to 60 Business Days after the effective date of these procedures.

1.1.4 Prior to submitting its Interconnection Request (Attachment 2), the Interconnection Customer may ask the Transmission Provider's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Transmission Provider shall respond within 15 Business Days.

1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Federal Energy Regulatory Commission expects all Transmission Providers, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure

Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.6 References in these procedures to interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

1.2 Pre-Application

1.2.1 The Transmission Provider shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the Transmission Provider's Internet web site. 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. The Transmission Provider shall comply with reasonable requests for such information.

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 written request form along with a non-refundable 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 20 Business Days of receipt of the completed request form and payment of the $300 fee. The pre-application report produced by the Transmission Provider is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Transmission Provider's system. The written pre-application report request form shall include the information in sections 1.2.2.1 through 1.2.2.8 below to clearly and sufficiently identify the location of the proposed Point of Interconnection.

1.2.2.1 Project contact information, including name, address, phone number, and email address.

1.2.2.2 Project location (street address with nearby cross streets and town)

1.2.2.3 Meter number, pole number, or other equivalent information identifying proposed Point of Interconnection, if available.

1.2.2.4 Generator Type (e.g., solar, wind, combined heat and power, etc.)

1.2.2.5 Size (alternating current kW)

1.2.2.6 Single or three phase generator configuration

1.2.2.7 Stand-alone generator (no onsite load, not including station service – Yes or No?)

1.2.2.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.2.3. Using the information provided in the pre-application report request form in section 1.2.2, the Transmission Provider will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the Transmission Provider does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional pre-application reports if information about multiple Points of Interconnection is requested. Subject to section 1.2.4, the pre-application report will include the following information:

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

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

1.2.3.3 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 the proposed Point of Interconnection.

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

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

1.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.2.3.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 2.4.4.1.1 below and absolute minimum load, when available.

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

1.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.2.3.13 Based on the 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 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 the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on "available capacity" pursuant to section 1.2.3.4 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 the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the Transmission Provider shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

1.3 Interconnection Request

The Interconnection Customer shall submit its Interconnection Request to the Transmission Provider, together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be date- and time-stamped upon receipt. The original date- and time-stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the Transmission Provider within three Business Days of receiving the Interconnection Request. 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. If the Interconnection Request is incomplete, the Transmission Provider shall provide along with the notice that the Interconnection Request is incomplete, a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will

have ten Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the Transmission Provider.

1.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the Transmission Provider and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the changes are undertaken.

1.5 Site Control

Documentation of site control must be submitted with the Interconnection Request. Site control may be demonstrated through:

1.5.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.5.2 An option to purchase or acquire a leasehold site for such purpose; or

1.5.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

1.6 Queue Position

The Transmission Provider shall assign a Queue Position based upon the date- and time-stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The Transmission Provider shall maintain a single queue per geographic region. At the Transmission

Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the system impact study.

1.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP

Nothing in this SGIP affects an Interconnection Customer's Queue Position assigned before the effective date of this SGIP. The Parties agree to complete work on any interconnection study agreement executed prior the effective date of this SGIP in accordance with the terms and conditions of that interconnection study agreement. Any new studies or other additional work will be completed pursuant to this SGIP.

Section 2. Fast Track Process

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's ~~Transmission~~ Distribution System if the Small Generating Facility ~~is no larger than 2 MW and if~~'s capacity does not exceed the size limits identified in the table below. Small Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Fast Track screens in section 2.2.1 below or the Supplemental Review screens in section 2.4.1 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Small Generating Facilities connecting to lines greater than 69 kilovolt (kV) are ineligible for the Fast Track Process regardless of size. All synchronous and induction machines must be no larger than 2 MW to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Small Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition to the size threshold, the Interconnection Customer's proposed Small Generating Facility must meet~~s~~ the codes, standards, and certification requirements of Attachments 3 and 4 of these

procedures, or the Transmission Provider has to have reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline[1] and ≤ 2.5 Electrical Circuit Miles from Substation[2]
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

2.2 Initial Review

Within 15 Business Days after the Transmission Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Transmission Provider shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens.

2.2.1 Screens

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff.

[1] For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[2] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to section 1.2.

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.

2.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.[3]

2.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

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.

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

[3] A spot network is a type of distribution system found within modern commercial buildings to provide high reliability of service to a single customer. (Standard Handbook for Electrical Engineers, 11th edition, Donald Fink, McGraw Hill Book Company)

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.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass Screen

2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

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

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).

2.2.1.10 No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility.

2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.3 If the proposed interconnection fails the screens, but the Transmission Provider determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.4 If the proposed interconnection fails the screens, ~~but~~and the Transmission Provider does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Transmission Provider shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

2.3 Customer Options Meeting

If the Transmission Provider determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost~~;~~, (2) ~~or~~ a supplemental study or other additional studies or actions~~;~~, or (3) ~~or at~~ incurring significant cost to address safety, reliability, or power quality problems, ~~within the five Business Day period after the determination,~~ the Transmission Provider shall notify the Interconnection Customer of that determination within five Business Days after the determination and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Transmission Provider's determination, the Transmission Provider shall offer to convene a customer options meeting with the Transmission Provider to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Transmission Provider's determination, or at the customer options meeting, the Transmission Provider shall:

2.3.1 Offer to perform facility modifications or minor modifications to the Transmission Provider's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost

to make such modifications to the Transmission Provider's electric system. If the Interconnection Customer agrees to pay for the modifications to the Transmission Provider's electric system, the Transmission Provider will provide the Interconnection Customer with an executable interconnection agreement within ten Business Days of the customer options meeting; or

2.3.2 Offer to perform a supplemental review in accordance with section 2.4 ~~if the Transmission Provider concludes that the supplemental review might determine that the Small Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process,~~ and provide a non-binding good faith estimate of the costs of such review; or

2.3.3 Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the section 3 Study Process.

2.4 Supplemental Review

2.4.1 ~~If the Interconnection Customer agrees to~~To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing ~~within 15 Business Days of the offer,~~ and submit a deposit for the estimated costs of the supplemental review in the amount of the Transmission Provider's good faith estimate of the costs of such review, both within 15 Business Days of the offer. If the written agreement and deposit have not been received by the Transmission Provider within that timeframe, the Interconnection Request shall continue to be evaluated under the section 3 Study Process unless it is withdrawn by the Interconnection Customer.

2.4.2 The Interconnection Customer may specify the order in which the Transmission Provider will complete the screens in section 2.4.4.

2.4.3 The Interconnection Customer shall be responsible for the Transmission Provider's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Transmission Provider will return such excess within 20 Business Days of the invoice without interest.

2.4.4 Within ~~ten~~30 Business Days following receipt of the deposit for a supplemental review, the Transmission Provider ~~will determine if the Small Generating Facility can be interconnected safely and reliably~~shall (1) perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of supplemental review, the Transmission Provider shall notify the Interconnection Customer following the failure of any of the screens, or if it is unable to perform the screen in section 2.4.4.1, within two Business Days of making such determination to obtain the Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this section 2.4.4; (2) terminate the supplemental review and continue evaluating the Small Generating Facility under section 3; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer.

2.4.4.1 ~~If so, the Transmission Provider shall forward an executable interconnection agreement to the Interconnection Customer within five Business Days~~ Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Generating Facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the Transmission Provider shall include

the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 2.4.4.

2.4.4.1.1 The type of generation used by the proposed Small Generating Facility will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 2.4.1.1. Solar photovoltaic (PV) 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 PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

2.4. 4.1.2 When this screen is being applied to a Small Generating Facility that serves some station service load, only the net injection into the Transmission Provider's electric system will be considered as part of the aggregate generation.

2.4. 4.1.3 Transmission 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.

2.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

2.4.4.3 Safety and Reliability Screen: The location of the proposed Small 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 the Study Process. The Transmission Provider shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

2.4.4.3.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

2.4.4.3.2 Whether the loading along the line section uniform or even.

2.4.4.3.3 Whether the proposed Small Generating Facility is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

2.4.4.3.4 Whether the proposed Small 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.

2.4.4.3.5 Whether operational flexibility is reduced by the proposed Small Generating Facility, such that transfer of the line section(s) of the Small Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

2.4.4.3.6 Whether the proposed Small Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

2.4.5 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer with an executable interconnection agreement within the timeframes established in sections 2.4.5.1 and 2.4.5.2 below. If the proposed interconnection fails any of the supplemental review screens and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the section 3 Study Process consistent with section 2.4.5.3 below.

2.4.5.1 If the proposed interconnection passes the supplemental screens in sections 2.4.1.1, 2.4.1.2, and 2.4.1.3 above and does not require construction of facilities by the Transmission Provider on its own system, the interconnection agreement shall be provided within ten Business Days after the notification of the supplemental review results.

2.4.5.2 If interconnection facilities or minor modifications to the Transmission Provider's system are required for the proposed interconnection to pass the supplemental screens in sections 2.4.1.1, 2.4.1.2, and 2.4.1.3 above, and the Interconnection Customer agrees to pay for the modifications to the Transmission Provider's electric system, the interconnection agreement, along with a non-binding good faith estimate for the interconnection facilities and/or minor modifications, shall be provided to the Interconnection Customer within 15 Business Days after receiving written notification of the supplemental review results.

2.4.5.3 If the proposed interconnection would require more than interconnection facilities or minor modifications to the Transmission Provider's system to pass the supplemental screens in sections 2.4.1.1, 2.4.1.2, and 2.4.1.3 above, the Transmission Provider shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the section 3 Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

~~2.4.1.2 If so, and Interconnection Customer facility modifications are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Transmission Provider shall forward an executable interconnection agreement to the Interconnection Customer within five Business Days after confirmation that the Interconnection Customer has agreed to make the necessary changes at the Interconnection Customer's cost.~~

~~2.4.1.3 If so, and minor modifications to the Transmission Provider's electric system are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under the Fast Track Process, the Transmission Provider shall forward an executable interconnection agreement to the Interconnection Customer within ten Business Days that requires the Interconnection Customer to pay the costs of such system modifications prior to interconnection.~~

~~2.4.1.4 If not, the Interconnection Request will continue to be evaluated under the section 3 Study Process.~~

Section 3. Study Process

3.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Transmission System or Distribution System if the Small Generating Facility (1) is larger than 2 MW but no larger than 20 MW, (2) is not certified, or (3) is certified but did not pass the Fast Track Process or the 10 kW Inverter Process.

3.2 Scoping Meeting

3.2.1 A scoping meeting will be held within ten Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The Transmission Provider and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.

3.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the Transmission Provider should perform a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the Parties agree that a feasibility study should be performed, the Transmission Provider shall provide the Interconnection Customer, as soon as possible, but not later than five Business Days after the scoping meeting, a feasibility study agreement (Attachment 6) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested a feasibility study must return the executed feasibility study agreement within 15 Business Days. If the Parties agree not to perform a feasibility study, the Transmission Provider shall provide the Interconnection Customer, no later than five Business Days after the scoping meeting, a system impact study agreement (Attachment 7) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.3 Feasibility Study

3.3.1 The feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the Small Generating Facility.

3.3.2 A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

3.3.3 The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (Attachment 6).

3.3.4 If the feasibility study shows no potential for adverse system impacts, the Transmission Provider shall send the Interconnection Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If no additional facilities are required, the Transmission Provider shall send the Interconnection Customer an executable interconnection agreement within five Business Days.

3.3.5 If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

3.4 System Impact Study

3.4.1 A system impact study shall identify and detail the electric system impacts that would result if the proposed Small Generating Facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

3.4.2 If no transmission system impact study is required, but potential electric power Distribution System adverse system impacts are identified in the scoping meeting or shown in the feasibility study, a distribution system impact study must be performed. The Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement within 15 Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith

estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

3.4.3 In instances where the feasibility study or the distribution system impact study shows potential for transmission system adverse system impacts, within five Business Days following transmittal of the feasibility study report, the Transmission Provider shall send the Interconnection Customer a transmission system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required.

3.4.4 If a transmission system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been conducted, the Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement.

3.4.5 If the feasibility study shows no potential for transmission system or Distribution System adverse system impacts, the Transmission Provider shall send the Interconnection Customer either a facilities study agreement (Attachment 8), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

3.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within 30 Business Days.

3.4.7 A deposit of the good faith estimated costs for each system impact study may be required from the Interconnection Customer.

3.4.8 The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement.

3.4.9 Where transmission systems and Distribution Systems have separate owners, such as is the case with transmission-dependent utilities ("TDUs") – whether investor-owned or not – the Interconnection Customer may apply to the nearest Transmission Provider (Transmission Owner, Regional Transmission Operator, or Independent Transmission Provider) providing transmission service to the TDU to request project coordination. Affected

Systems shall participate in the study and provide all information necessary to prepare the study.

3.5 Facilities Study

3.5.1 Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the Interconnection Customer along with a facilities study agreement within five Business Days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the Interconnection Customer within the same timeframe.

3.5.2 In order to remain under consideration for interconnection, or, as appropriate, in the Transmission Provider's interconnection queue, the Interconnection Customer must return the executed facilities study agreement or a request for an extension of time within 30 Business Days.

3.5.3 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

3.5.4 Design for any required Interconnection Facilities and/or Upgrades shall be performed under the facilities study agreement. The Transmission Provider may contract with consultants to perform activities required under the facilities study agreement. The Interconnection Customer and the Transmission Provider may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Transmission Provider, under the provisions of the facilities study agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the Transmission Provider shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

3.5.5 A deposit of the good faith estimated costs for the facilities study may be required from the Interconnection Customer.

3.5.6 The scope of and cost responsibilities for the facilities study are described in the attached facilities study agreement.

3.5.7 Upon completion of the facilities study, and with the agreement of the Interconnection Customer to pay for Interconnection Facilities and Upgrades identified in the facilities study, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days.

Section 4. Provisions that Apply to All Interconnection Requests

4.1 Reasonable Efforts

The Transmission Provider shall make reasonable efforts to meet all time frames provided in these procedures unless the Transmission Provider and the Interconnection Customer agree to a different schedule. If the Transmission Provider cannot meet a deadline provided herein, it shall notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

4.2 Disputes

4.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

4.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

4.2.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation,

settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

4.2.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

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

4.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Federal Energy Regulatory Commission, state, or local regulatory requirements or the Transmission Provider's specifications.

4.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. The Transmission Provider must be given at least five Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

4.5. Confidentiality

4.5.1 Confidential information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such.

4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each

Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

4.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

4.5.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

4.5.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC. The Party shall notify the other Party when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

4.6 Comparability

The Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this document. The Transmission

Provider shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Small Generating Facility is owned or operated by the Transmission Provider, its subsidiaries or affiliates, or others.

4.7 Record Retention

The Transmission Provider shall maintain for three years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

4.8 Interconnection Agreement

After receiving an interconnection agreement from the Transmission Provider, the Interconnection Customer shall have 30 Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement or request that the Transmission Provider file an unexecuted interconnection agreement with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted by the Transmission Provider within 30 Business Days, the Interconnection Request shall be deemed withdrawn. After the interconnection agreement is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

4.9 Coordination with Affected Systems

The Transmission Provider shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The Transmission Provider will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with the Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

4.10 Capacity of the Small Generating Facility

4.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total capacity of the Small Generating Facility.

4.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

4.10.3 The Interconnection Request shall be evaluated using the maximum ~~rated~~ capacity ~~of~~that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system. However, if the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system is limited (e.g., through use of a control system, power relay(s), or other similar device settings or adjustments), then the Interconnection Customer must obtain the Transmission Provider's agreement, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to implement such a limit will not adversely affect the safety and reliability of the Transmission Provider's system. If the Transmission Provider does not so agree, then the Interconnection Request must be withdrawn or revised to specify the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system without such limitations. Furthermore, nothing in this section shall prevent a Transmission Provider from considering an output higher than the limited output, if appropriate, when evaluating system protection impacts.

Attachment 1
Glossary of Terms

10 kW Inverter Process – The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

Affected System – An electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Business Day – Monday through Friday, excluding Federal Holidays.

Distribution System – The Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility ~~no larger than 2 MW~~ that meets the eligibility requirements of section 2.1 and includes the section 2 screens, customer options meeting, and optional supplemental review.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Interconnection Customer – Any entity, including the Transmission Provider, the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect its Small Generating Facility with the Transmission Provider's Transmission System.

Interconnection Facilities – The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request – The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Resource – Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service – An Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades – Additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Transmission Provider's Transmission System to accommodate the interconnection with the Small Generating Facility to the

Transmission Provider's Transmission System. Network Upgrades do not include Distribution Upgrades.

Party or Parties – The Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Transmission Provider's Transmission System.

Queue Position – The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Small Generating Facility – The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Study Process – The procedure for evaluating an Interconnection Request that includes the section 3 scoping meeting, feasibility study, system impact study, and facilities study.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.

Transmission Provider – The public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission System – The facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service under the Tariff.

Upgrades – The required additions and modifications to the Transmission Provider's Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2
SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)

Transmission Provider: _____

Designated Contact Person: _____

Address: _____

Telephone Number: _____

Fax: _____

E-Mail Address: _____

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request.

Preamble and Instructions

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the Transmission Provider.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is $500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the Transmission Provider a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: _____

Contact Person: _____

Mailing Address: _____

City: _____ State: _____ Zip: _____

Facility Location (if different from above): _____

_____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: _____

Title: _____

Address: _____

_____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Application is for: _____New Small Generating Facility

_____Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: _____

_____

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___

To Supply Power to the Interconnection Customer? Yes ___No ___

To Supply Power to Others? Yes ____ No ____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

_____ _____

(Local Electric Service Provider*) (Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Transmission Provider]

Contact Name: _____

Title: _____

Address: _____

_____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Requested Point of Interconnection: _____

_____

Interconnection Customer's Requested In-Service Date: _____

Small Generating Facility Information

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___Solar ___Wind ___Hydro ___ Hydro Type (e.g. Run-of-River):_____
__Diesel __ Natural Gas __ Fuel Oil Other (state type) _____

Prime Mover: __Fuel Cell __Recip Engine __Gas Turb __Steam Turb
__Microturbine __PV __Other

Type of Generator: ____Synchronous ____Induction ____ Inverter

Generator Nameplate Rating: _____kW (Typical) Generator Nameplate kVAR: _____

Interconnection Customer or Customer-Site Load: _____kW (if none, so state)

Typical Reactive Load (if known): _____

Maximum Physical Export Capability Requested: _____ kW

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.	_____	_____
2.	_____	_____
3.	_____	_____
4.	_____	_____
5.	_____	_____

Is the prime mover compatible with the certified protective relay package? ____Yes ____No

Generator (or solar collector) Manufacturer, Model Name & Number: _____

Version Number: _____

Nameplate Output Power Rating in kW: (Summer) _____ (Winter) _____

Nameplate Output Power Rating in kVA: (Summer) _____ (Winter) _____

Individual Generator Power Factor

Rated Power Factor: Leading: _____Lagging: _____

Total Number of Generators in wind farm to be interconnected pursuant to this

Interconnection Request: _____ Elevation:_____ ___Single phase ___Three phase

Inverter Manufacturer, Model Name & Number (if used):_____

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

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _____ Instantaneous or RMS_____?
Harmonics Characteristics: _____
Start-up requirements: _____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____

(*) Neutral Grounding Resistor (If Applicable): _____

Synchronous Generators:
Direct Axis Synchronous Reactance, X_d: _____ P.U.
Direct Axis Transient Reactance, X'_d: _____P.U.
Direct Axis Subtransient Reactance, X''_d: _____P.U.
Negative Sequence Reactance, X_2: _____ P.U.
Zero Sequence Reactance, X_0: _____ P.U.

KVA Base: _____
Field Volts: _____
Field Amperes: _____

Induction Generators:
Motoring Power (kW): _____
I22t or K (Heating Time Constant): _____
Rotor Resistance, Rr: _____
Stator Resistance, Rs: _____
Stator Reactance, Xs: _____
Rotor Reactance, Xr: _____
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

Note: Please contact the Transmission Provider prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only
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.

Interconnection Facilities Information

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? Size: _____kVA
Transformer Impedance: _____% 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.	_____	_____	_____
4.	_____	_____	_____
5.	_____	_____	_____
6.	_____	_____	_____

If Discrete Components:

(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:_____
Manufacturer:_____	Type:____	Style/Catalog No.:_____	Proposed Setting:_____
Manufacturer:_____	Type:____	Style/Catalog No.:_____	Proposed Setting:_____

Current Transformer Data (If Applicable):
(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: _____

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

Manufacturer: _____

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

Potential Transformer Data (If Applicable):

Manufacturer: _____

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

Manufacturer: _____

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

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small 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 Small Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ____Yes ____No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address)_____

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

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: _____ Date: _____

Attachment 3
Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment 4
Certification of Small Generator Equipment Packages

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

Attachment 5

Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW ("10 kW Inverter Process")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider ("Company").

2.0 The Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The Company evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The Company has 15 Business Days to complete this process. Unless the Company determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Company approves the Application and returns it to the Customer. Note to Customer: Please check with the Company before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the Company. Prior to parallel operation, the Company may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.

6.0 The Company notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Company has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Company is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Company does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Company, that contact information must be provided on the Application.

8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of $100 must accompany this Application.

Interconnection Customer

Name: _____

Contact Person: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Contact (if different from Interconnection Customer)

Name: _____

Contact Person: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Owner of the facility (include % ownership by any electric utility): _____

_____

Small Generating Facility Information

Location (if different from above): _____

Electric Service Company: _____

Account Number: _____

Inverter Manufacturer: _____ Model: _____
Nameplate Rating:_____(kW) _____(kVA) _____(AC Volts)

Single Phase ____ Three Phase____

System Design Capacity: _____ (kW) _____ (kVA)

Prime Mover: ___Photovoltaic ___Reciprocating Engine ___Fuel Cell

___Turbine ___Other (describe)_____

Energy Source: ___Solar ___Wind ___Hydro ___Diesel ___Natural Gas

___Fuel Oil ___Other (describe) _____

Is the equipment UL1741 Listed? ___Yes ___No

If Yes, attach manufacturer's cut-sheet showing UL1741 listing
Estimated Installation Date: _____Estimated In-Service Date: _____

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small Generator Interconnection Procedures (SGIP), or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.	_____	_____
2.	_____	_____
3.	_____	_____
4.	_____	_____
5.	_____	_____

Interconnection Customer Signature

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.

Signed: _____
Title: _____ Date: _____

Contingent Approval to Interconnect the Small Generating Facility
(For Company use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Company Signature: _____

Title: _____ Date: _____

Application ID number: _____

Company waives inspection/witness test? Yes___No___

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes_____ No _____

Interconnection Customer: _____

Contact Person: _____

Address: _____

Location of the Small Generating Facility (if different from above): _____

_____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Electrician:

Name: _____

Address: _____

Location of the Small Generating Facility (if different from above): _____

_____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

License number: _____

Date Approval to Install Facility granted by the Company: _____

Application ID number: _____

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local building/electrical code of: _____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

_____

Print Name: _____

Date: _____

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert Company information below):

Name: _____

Company: _____

Address: _____

_____

City, State ZIP: _____

Fax: _____

.....

Approval to Energize the Small Generating Facility (For Company use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Company Signature: _____

Title: _____ Date: _____

Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Transmission Provider (the "Company") approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Company's electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 Safe Operations and Maintenance

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 Access

The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 Disconnection

The Company may temporarily disconnect the Small 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 Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 Indemnification

The Parties shall at all times indemnify, defend, and save 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 other 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 Parties agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

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

The agreement to operate in parallel may be terminated under the following conditions:

9.1 **By the Customer**

By providing written notice to the Company.

9.2 **By the Company**

If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 **Permanent Disconnection**

In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

9.4 **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/Transfer of Ownership of the Facility

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

Attachment 6
Feasibility Study Agreement

THIS AGREEMENT is made and entered into this _____day of _____

20___ 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_____,

("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on_____; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 A deposit of the lesser of 50 percent of good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 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 _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. 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.

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

15.0 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.

16.0 Waiver

16.1 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.

16.2 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 other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

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

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or 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.

19.0 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.

20.0 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 primarily liable to the other Party for the performance of such subcontractor.

20.1 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 the Transmission Provider 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.

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

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

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.

[Insert name of Transmission Provider]	[Insert name of Interconnection Customer]
_____	_____
Signed: _____	Signed: _____
Name (Printed):	Name (Printed):
_____	_____
Title: _____	Title: _____

Attachment A to
Feasibility Study Agreement

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on _____:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 7
System Impact Study Agreement

THIS AGREEMENT is made and entered into this _____day of_____

20___ 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_____,

("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on_____; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A deposit of the equivalent of the good faith estimated cost of a distribution system impact study and the one half the good faith estimated cost of a transmission system impact study may be required from the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 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 _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. 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.

14.0 Amendment

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

15.0 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.

16.0 Waiver

16.1 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.

16.2 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 other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

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

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or 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.

19.0 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.

20.0 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 primarily liable to the other Party for the performance of such subcontractor.

20.1 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 the Transmission Provider 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.

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

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to

modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications

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.

[Insert name of Transmission Provider]	[Insert name of Interconnection Customer]
_____	_____
Signed: _____	Signed: _____
Name (Printed):	Name (Printed):
_____	_____
Title: _____	Title: _____

Attachment A to System Impact Study Agreement

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 8
Facilities Study Agreement

THIS AGREEMENT is made and entered into this _____day of_____

20___ 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_____,

("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on_____; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study in accordance with Good Utility Practice to physically and electrically connect the Small Generating Facility with the Transmission Provider's Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause a facilities study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.

4.0 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s). The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Transmission Provider's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

5.0 The Transmission Provider may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.

6.0 A deposit of the good faith estimated facilities study costs may be required from the Interconnection Customer.

7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a draft facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the draft facilities study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Interconnection Customer may, within 30 Calendar Days after receipt of the draft report, provide written comments to Transmission Provider, which Transmission Provider shall include in the final report. Transmission Provider shall issue the final Interconnection Facilities Study report within 15 Business Days of receiving Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen-day period upon notice to Interconnection Customer if Interconnection Customer's comments

require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 4.5 of the standard Small Generator Interconnection Procedures.

10.0 Within ten 10 Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

~~9~~11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

~~10~~12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

~~11~~13.0 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 _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. 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.

~~12~~14.0 Amendment

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

~~13~~15.0 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.

~~14~~16.0 Waiver

~~14~~16.1 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.

~~14~~16.2 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 other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

~~15~~17.0 Multiple Counterparts

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

~~16~~18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or 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.

~~17~~19.0 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.

~~18~~20.0 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 primarily liable to the other Party for the performance of such subcontractor.

~~18~~20.1 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 the Transmission Provider 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.

~~18~~20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

~~19~~21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications

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.

[Insert name of Transmission Provider]	[Insert name of Interconnection Customer]
_____	_____
Signed_____	Signed_____
Name (Printed):	Name (Printed):
_____	_____
Title_____	Title_____

Attachment A to
Facilities Study Agreement

Data to Be Provided by the Interconnection Customer
with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections: _____

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes ____ No ____

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ____ No ____
(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

_____

_____

What protocol does the control system or PLC use?

_____

_____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

_____

Bus length from generation to interconnection station:

_____

Line length from interconnection station to Transmission Provider's Transmission System.

_____

Tower number observed in the field. (Painted on tower leg)*:

_____

Number of third party easements required for transmission lines*:

_____

* To be completed in coordination with Transmission Provider.

Is the Small Generating Facility located in Transmission Provider's service area?
Yes _____ No _____ If No, please provide name of local provider:

_____

Please provide the following proposed schedule dates:

Begin Construction	Date: _____
Generator step-up transformers receive back feed power	Date: _____
Generation Testing	Date: _____
Commercial Operation	Date: _____

Note: Appendix D will not appear in the Code of Federal Regulations.

Appendix D: Revisions to the *Pro Forma* SGIA

Section number	Revision
3.3.5 (Termination)	Replace the first word of the section (''This'') with ''The''.
Attachment 1 (Glossary of Terms)	Revise the definition of Small Generating Facility as follows: Small Generating Facility—The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

[FR Doc. 2013–28515 Filed 12–4–13; 8:45 am]

BILLING CODE 6717–01–C