February 22, 2013

Proposed PSC 119 Interconnection Administrative Rule Changes

1. External Disconnect Switch Exemption for Category 1 and Category 2 DG Facilities that Utilize an Inverter, Converter, Controller and Interconnection System Certified by a Nationally Recognized Testing Laboratory Meeting the Applicable Type Testing Requirements of the current version of UL 1741 in PSC 229.1 and PSC 119.2.
2. Fast Track Interconnection Process Section to be incorporated as PSC 119.041.
3. Streamlining the Interconnection Application Process Timelines in PSC 119.04.
4. Setting DG Requirements of Spot or Secondary Network Service to National Standards in PSC 119.20 (13).
5. Cost-Effective DG Telemetry in PSC 119.25 (3) (b) 6
6. Dispute Resolution and Referencing §196.26 Wis. Stats. (Complaint by consumers…) in PSC 119.40 (Right to appeal…).
7. Refining Interconnection Insurance Requirements in PSC 119.05
8. Updating Interconnection Application and Agreement Forms in PSC-6027 R, PSC-6028 R, PSC-6029 R, and PSC-6030 R.
9. Line Extensions and Modifications for DG Facilities in PSC 119.04 (8) and PSC 119.08.
10. Defining the Categories of DG Facilities in Terms of Capacity in PSC 119.02.

1. External Disconnect Switch Exemption for Category 1 and Category 2 DG Facilities that Utilize an Inverter, Converter, Controller and Interconnection System Certified by a Nationally Recognized Testing Laboratory Meeting the Applicable Type Testing Requirements of the current version of UL 1741 in PSC 229.1 and PSC 119.2.

Rationale

"The utility-accessible alternating current (AC) external disconnect switch (EDS) for distributed generators, including photovoltaic (PV) systems, is a hardware feature that allows a utility's employees to manually disconnect a customer-owned generator from the electricity grid. Proponents of the EDS contend that it is necessary to keep utility line workers safe when they make repairs to the electric distribution system. Opponents assert it is a redundant feature that adds cost without providing tangible benefits[1]

"In the event of a feeder outage, a line crew will risk injury from a PV system only if all of the following events occur:
1. The inverter fails to disconnect automatically and somehow produces power without the necessary external voltage source present.
2. The anti-islanding, voltage, and frequency methods fail in the inverter.
3. The load at the output of the inverter matches the connected load of the PV owner and adjacent customers. (This is statistically improbable.)
4. The line worker chooses to work the line energized but fails to follow procedures.
5. The line worker chooses to work the line de-energized but fails to test and ground the line."[2]

"Solar stakeholders argue that modern UL-listed inverters have virtually eliminated risk for utility line workers and that with the more than 220,000 interconnected PV systems in the United States, there has not been a single line worker injury caused by an inverter-based PV system." [3]

"In a number of states in which public utility commissions (PUCs) and utilities have gained experience with PV systems, they have decided to eliminate the EDS requirement. These decisions typically require that utility-interactive PV systems use inverters that meet relevant Underwriters Laboratories (UL) and Institute of Electrical and Electronics Engineers (IEEE) standards."[4]

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[1] Coddington, M.H. Margolis, R.M. and Aabakken, J. *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*. January 2008. Technical Paper: NREL/TP-581-42675.

[2] Ibid.

[3] See IREC Solar Market Trends 2011 at p 4.

[4] Coddington, et al.

"Because Federal Energy Regulatory Commission Order 2006 for the interconnection of distributed generators does not require EDSs, there is no federal policy governing this issue."[5]

"The additional costs of processing and approving the installation of an EDS may be borne by the customer (increasing the PV system cost) or the utility (increasing electricity rates for all customers)."[6]

UL 1741 is the Underwriters Laboratory standard titled "Standard for Safety of Inverters, Converters, Controllers and Interconnection System Equipment for Use in Independent Power Systems". The anti-islanding protection of DG equipment meeting the UL 1741 standard is typically sufficient for smaller systems that do not contribute a large percentage of electric power to a distribution feeder circuit e.g., Category 1 & 2 DG facility.

Current Situation:
PSC 119.02 (21) defines an "Interconnection disconnect switch" to mean a mechanical device used to disconnect a DG facility from a distribution system.

PSC 119.20 (3) states that the *public utility may require that the applicant furnish and install an interconnection disconnect* switch that opens, with a visual break, all ungrounded poles of the interconnection circuit. The interconnection disconnect switch shall be rated for the voltage and fault current requirements of the DG facility, and shall meet all applicable UL, ANSI, and IEEE standards. The switch enclosure shall be properly grounded. The interconnection disconnect switch shall be accessible at all times, located for ease of access to public utility personnel, and shall be capable of being locked in the open position. The applicant shall follow the public utility's recommended switching, clearance, tagging, and locking procedures.

PSC 119.26 (Certified paralleling equipment) defines DG paralleling equipment as that which a nationally recognized testing laboratory certifies as meeting the applicable type testing requirements of UL 1741 (January 17, 2001 revision) is acceptable for interconnection, without additional protection systems, to the distribution system.

PSC 119.02 defines "Nationally recognized testing laboratory" to mean any testing laboratory recognized by the U.S. Department of Labor Occupational Safety and Health Administration's accreditation program.

➔ **Proposal for Not Requiring an Interconnection Disconnect Switch for Category 1 and Category 2 DG Facilities that Utilize an Inverter, Converter, Controller and Interconnection System Certified by a Nationally Recognized Testing Laboratory Meeting the Applicable Type Testing Requirements of the current version of UL 1741**

[5] Ibid.
[6] Ibid.

Suggested changes to PSC 119 **(changes in red)**

PSC 119.10 One−line schematic diagram. (1) The applicant shall include an one−line schematic diagram with the completed standard application form. ANSI symbols shall be used in the one−line schematic diagram to show the following:

(a) Generator or inverter.

(b) Point where the DG facility is electrically connected to the customer's electrical system.

(c) Point of common coupling.

(d) Lockable interconnection disconnect switch, **if used**.

(e) Method of grounding, including generator and transformer ground connections.

(f) Protection functions and systems.

PSC 119.10 (2) The applicant shall include with the schematic diagram technical specifications of the point where the DG facility is electrically connected to the customer's electrical system, including all anti−islanding and power quality protective systems. The specifications regarding the anti−islanding protective systems shall describe all automatic features provided to disconnect the DG facility from the distribution system in case of loss of grid power, including the functions for over/under voltage, over/under frequency, over current, and loss of synchronism. The applicant shall also provide technical specifications for the generator, lockable interconnection disconnect switch, **if used**, and grounding and shall attach the technical specification sheets for any certified equipment. The applicant shall include with the schematic diagram a statement by the manufacturer that its equipment meets or exceeds the type-tested requirements for certification.

PSC 119.12 Site plan. For all categories **(exemption for Category 1 and Category 2 DG Facilities that Utilize an Inverter, Converter, Controller and Interconnection System Certified by a Nationally Recognized Testing Laboratory Meeting the Applicable Type Testing Requirements of the current version of UL 1741)**, the applicant shall include with the application a site plan that shows the location of the interconnection disconnect switch, adjoining street name, and the street address of the DG facility. For Category 3 and 4 DG facilities, the site plan shall show the location of major equipment, electric service entrance, electric meter, interconnection disconnect switch, and interface equipment.

PSC 119.20 (3) The public utility may require that the applicant furnish and install an interconnection disconnect switch **(exemption for Category 1 and Category 2 DG Facilities that Utilize an Inverter, Converter, Controller and Interconnection System Certified by a Nationally Recognized Testing Laboratory Meeting the Current Applicable Type Testing Requirements of UL 1741)** that opens, with a visual break, all ungrounded poles of the interconnection circuit. The interconnection disconnect switch shall be rated for the voltage and fault current requirements of the DG facility, and shall meet all applicable UL, ANSI, and IEEE standards. The switch enclosure shall be properly grounded. The interconnection disconnect switch shall be accessible at all times, located for ease of access to public utility personnel, and shall be capable of being locked in the open position. The applicant shall follow the public utility's recommended switching, clearance, tagging, and locking procedures.

119.20 (4) The applicant shall label the interconnection disconnect switch, **if used**, "Interconnection Disconnect Switch" by means of a permanently attached sign with clearly visible and permanent letters. The applicant shall provide and post its procedure for disconnecting the DG facility next to the switch.

2. Fast Track Interconnection Process in Section PSC 119.041 and PSC 119.02

Rationale

"Interconnection procedures vary depending on state or federal jurisdiction, and implementation practices vary by utility system. Most procedures allow for expedited interconnection without additional technical studies if the proposed interconnection passes a series of technical screens. If a proposed interconnection fails one or more of the screens, supplemental interconnection studies may be required before it can proceed to interconnection. These supplemental studies may only add a few weeks or months to the interconnection approval process, but they have a significant impact on the time, cost, and uncertainty of the proposed project. And for many utilities and PV developers, the potential impacts from PV are not clearly understood and the supplemental studies are not well defined.

Thousands of applications are submitted in the United States each year for distributed generation installations and the number of applications are growing rapidly. Therefore, it is critical that interconnection procedures be as streamlined as possible to avoid unnecessary interconnection studies, costs, and delays. There is an implicit expectation that existing interconnection procedures will evolve over time to reflect changes in standards, technology, and practical experience."[7]

These fast track screens were proposed by FERC to be a model for state rules and many states have adopted them, including the Midwest states of Illinois, Iowa, Ohio, South Dakota and others. There is great value in being consistent in adopting regional and national rules, standards and procedures, which promote efficiency and reliability.

Proposal for a Fast Track Interconnection Process in Wisconsin
(suggested to be listed as PSC 119.041 Screens for Fast Track Interconnection Process)

Applicability
The Fast Track Process is available to an applicant proposing to interconnect its DG facility, no larger than a *maximum DG facility size rating of* Alternative: 1, 2, 3 or 4 (see below) for fast track process, with the distribution system.

***Maximum DG Facility Size Rating*s Applicable to a Fast Track Process**
Alternatives for *the PSCW*:

- **Alternative 1: 2 MW (FERC SGIP)**
- **Alternative 2: 1 MW (max. allowed in PSC 119, Category 3)**
- **Alternative 3: 200 kW (max. allowed in PSC 119, Category 2)**
- **Alternative 4: 20 kW (max. allowed in PSC 119, Category 1)**

Initial Review

[7] Coddington, M., Mather, B., Kroposki, B. "Updating Interconnection Screens for PV System Integration". February 2012. Technical Paper: NREL/TP-5500-54063.

Within 10 working days after the public utility has received a completed standard application form, the public utility shall perform an initial review using the Fast Track Process screens, notify the applicant of the results, and include with the notification copies of the analysis and data underlying the public utilities' determinations under the screens.

Screens for Fast Track Process

Screen 1: Percentage Aggregated Generation (*Pass or Fail Screen*)

Radial Distribution Circuit:

For interconnection of a proposed DG facility, no larger than a *maximum DG facility size rating of Alternative 1, 2, 3 or 4*, to a radial distribution circuit, the aggregated generation, including the proposed DG facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation.
(Note: California and Hawaii are already running up against problems with this 15% screen and are replacing it with a new "supplemental review" for PV systems. See http://www.nrel.gov/docs/fy08osti/42675.pdf. Although Wisconsin may be a few years away from this level of PV penetration, things can change quickly and it may be preferable to start with the latest "best practices" represented by California Rule 21.)

Spot Network:

For interconnection of a proposed DG facility to the load side of spot network protectors, the proposed DG 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.

Screen 2: Short Circuit Interrupting Capability (*Pass or Fail Screen*)

The proposed DG 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 applicant's 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.

Screen 3: DG Interconnection is Compatible with Type of Primary (*Pass or Fail Screen*)

This screen includes a review of the type of electrical service provided to the applicant, including line configuration and the transformer connection to limit the potential for creating over-voltages on the public utilities distribution 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* if installation matches type of interconnection to primary distribution line.

Three-phase, four wire	**Effectively-grounded 3 phase or Single-phase, line-to-neutral**	***Pass screen*** **if installation matches type of interconnection to primary distribution line.**
	Single-phase shared secondary	***Pass screen*** **if the aggregate generation capacity on the shared secondary, including the proposed DG facility, does not exceed 20 kW**
	Single-phase and is to be interconnected on a center tap neutral of a 240 volt service	***Pass screen*** **if DG facility does 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**

Screen 4: Interconnection to Transmission Side of Substation in Stability-Limited Areas (*Pass or Fail Screen*)

The DG facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the DG 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).

Screen 5: DG Facility Can Be Interconnected Without Distribution System Upgrades (*Pass or Fail Screen*)

No construction of facilities by the public utility on its own system shall be required to accommodate the DG facility.

Results of Screen

If the proposed interconnection passes the screens, the standard application form shall be approved by the public utility will provide the applicant with a standard interconnection agreement within 5 working days after the determination.

If the proposed interconnection fails the screens, but the public utility determines that the DG facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards,

the public utility shall provide the applicant an executable interconnection agreement within 5 working days after the determination.

If the proposed interconnection fails the screens, but the public utility does not or cannot determine from the initial review that the DG facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the applicant is willing to consider minor modifications or further study, the public utility shall provide the applicant with the opportunity to attend a customer options meeting.

Post Installation Steps

The applicant shall notify the public utility when project construction is complete. Prior to parallel operation, the applicant shall give the public utility the opportunity to witness or verify the system testing, as required in s. PSC 119.30 or PSC 119.31.

Within 10 working days, the public utility notifies the applicant in writing of the results of witnessing or verifying (testing) of the DG facility interconnection.

> **a. If the witness test is satisfactory, the DG facility may operate in parallel.**
> **b. If the witness test is not satisfactory, the applicant may not operate in parallel and the public utility has the right to disconnect the DG facility.**
> **c. If the public utility does not inspect within 10 working days or by mutual agreement of the parties, the witness test is deemed waived and the DG facility may operate in parallel.**

Suggested changes to PSC 119 (changes in red)

PSC 119.26 Certified paralleling equipment. DG paralleling equipment that a nationally recognized testing laboratory certifies as meeting the applicable type testing requirements of UL 1741 (January 17, 2001 revision) is acceptable for interconnection, without additional protection systems, to the distribution system. The applicant may use certified paralleling equipment for interconnection to a distribution system without further review or testing of the equipment design by the public utility, but the use of this paralleling equipment does not automatically qualify the applicant to be interconnected to the distribution system at any point in the distribution system. The public utility may still require an engineering review to determine the compatibility of the distributed generation system with the distribution system capabilities at the selected point of common coupling **(exemption for systems using the Fast Track Interconnection Process)**.

Definitions

(suggested to be added to the PSC 119.02 Definitions)

Fast Track Process – A fast track process is an expedited interconnection process utilizing a series of technical screens without the use of additional technical studies.

Line Section - A line section is that portion of a public utilities' electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

Screens for a Fast Track Process – Screens for a fast track process means a series of technical interconnection questions the passing or failing of which provide a go-no-go determination of whether a study process is required.

Study Process – The study process is the review by the public utility of the completed standard application form for interconnection, to determine if an engineering review or distribution system study is needed – as delineated in PSC 119.04: Application process for interconnecting DG facilities.

Implementation Notes

A. This proposed fast track interconnection process has been adapted from the "Small Generator Interconnection Procedures" (SGIP), in effect August 28, 2006, per FERC Order No. 2006-B issued July 20, 2006, FERC Stats. &Regs. ¶ 31,221, which was published in the Federal Register July 27, 2006 (71 FR 42587), as amended by the errata issued September 5, 2006, which was published in the Federal Register September 13, 2006 (71 FR 53965). These procedures are applicable for generating facilities no larger than 20 MW. The SGIP fast track screens form the basis for the statewide interconnection procedures in a number of states, including the Midwest states of Illinois (Ill. Adm. Code Part 466), Iowa (199 IAC Ch. 45), Ohio (OAC Ch. 4901:1-22); and South Dakota (S.D. Adm. Code Ch. 20:10:36).

B. The regular application process for interconnecting DG facilities found in PSC 119.04 is suggested to be utilized for DG facilities larger than a ***maximum DG facility size rating of <u>Alternative 1,2,3,4</u>*** set for the fast track process. This process can be referred to as the Study Process to conform to FERC nomenclature.

3. Streamlining the Interconnection Application Process Timelines in PSC 119.04

Background Information

The time that it takes to process an interconnection application can directly affect the economics of a project. In the modern world with electronic communication and the ability to provide on-line forms, the timelines in PSC 119.04 can be streamlined in almost all categories, which will facilitate the speed and reduce the costs of installing distributed resources. Specifically for Category 1 DG Facilities, the market has evolved to achieve timeframes of days or even hours for complete DG Facility installation. The application process timeline for Category 1 can total up to a range of 40 to 60 working days, or 2 to 3 months. A timeline that reasonably supports the market's ability to implement systems will help support customer satisfaction, save time and costs.

Additionally, the PSC and utilities are encouraged to work with stakeholders to establish a standard web based interconnection application form and process to streamline the communication and processing times and reduce processing costs for utilities and all stakeholders.

PSC 119.04 allows for an application process timeline that exceeds FERC SGIP standards, and regional states for category 4 distributed generation facilities. PSC 119.04 allows the public utility up to 40 working days to complete an engineering review. The FERC SGIP standard allows a maximum of 30 working days for the engineering review. PSC 119.04 allows the public utility up to 60 working days to complete a distribution system study. The FERC SGIP standard allows a maximum of 30 working days for the distribution system study.

Streamlining the timelines in PSC 119.04 for distributed generation facility applications would move the interconnection process in Wisconsin towards national best practices.

➔ **Proposal for Shortening the Interconnection Application Process Timelines in PSC 119.04**

Suggested changes to PSC 119 (changes in red)

PSC 119.04 Application process for interconnecting DG facilities. Public utilities and applicants shall complete the following steps regarding interconnection applications for all classes of DG facilities, in the order listed:

(1) The public utility shall respond to each request for DG interconnection by furnishing, within 1 working day, its guidelines and the appropriate standard **on-line** application form.

(2) The applicant shall complete and submit the standard application form to its public utility **using an electronic signature, if desired.**

(3) The public utility shall notify the applicant whether the application is complete upon receiving a new or revised application within:

(a) Category 1 DG application, **1** working day.

(b) Category 2 DG application, **5** working days.

(c) Category 3 DG application, **5** working days.

(d) Category 4 DG application, **5** working days.

(4) Upon determining that the application is complete, the public utility shall complete its application review within:

(a) Category 1 DG application, **2** working day.

(b) Category 2 DG application, **5** working days.

(c) Category 3 DG application, **5** working days.

(d) Category 4 DG application, **10** working days.

If the public utility determines, on the basis of the application review that an engineering review is needed, it shall notify the applicant and state the cost of that review. For Categories 2 and 3, the cost estimate shall be valid for one year. For Category 4, the time period shall be negotiated but may not exceed one year. If the application review shows that an engineering review is not needed, the applicant may install the DG facility and need not complete the steps described in subs. (5) to (9).

(5) If the public utility determines on the basis of the application review that an engineering review is needed, upon receiving from the applicant written notification to proceed and receipt of applicable payment from the applicant, the public utility shall complete an engineering review and notify the applicant of the results within the following times:

(a) Category 1 DG application, **5** working days.

(b) Category 2 DG application, **10** working days.

(c) Category 3 DG application, **15** working days.

(d) Category 4 DG application, **20** working days.

(6) If the engineering review indicates that a distribution system study is necessary, the public utility shall include, in writing, a cost estimate in its engineering review. The cost estimate shall be valid for one year and the applicant shall have one year from receipt of the cost estimate in which to notify the public utility to proceed, except for a Category 4 DG application, in which case the time period shall be negotiated, but may not extend beyond one year. Upon receiving written notification to proceed and payment of the applicable fee, the public utility shall conduct the distribution system study.

(7) The public utility shall within the following time periods complete the distribution system study and provide study results to the applicant:

(a) Category 1 DG application, 10 working days.

(b) Category 2 DG application, 15 working days.

(c) Category 3 DG application, 20 working days.

(d) Category 4 DG application, **30** working days

(8) The public utility shall perform a distribution system study of the local distribution system and notify the applicant of findings along with any distribution system construction or modification costs to be borne by the applicant.

(9) If the applicant agrees, in writing, to pay for any required distribution system construction and modifications, the public utility shall complete the distribution system upgrades and the applicant shall install the DG facility within a time frame that is mutually agreed upon. The applicant shall notify the public utility when project construction is complete.

(10) (a) The applicant shall give the public utility the opportunity to witness or verify the system testing, as required in s. PSC 119.30 or 119.31. Upon receiving notification that an installation is complete, the

public utility has **5** working days, for a Category 1 or 2 DG project, or **10** working days, for a Category 3 or 4 DG project, to complete the following:

1. Witness commissioning tests.
2. Perform an anti−islanding test or verify the protective equipment settings at its expense.
3. Waive its right, in writing, to witness or verify the commissioning tests **and provide approval to interconnect to the applicant.**

(b) The applicant shall provide the public utility with the results of any required tests.

(11) The public utility may review the results of the on−site tests and shall notify the applicant within 1 working day, for a Category 1 DG project, or within **5** working days, for a Category 2 to 4 DG project, of its approval or disapproval of the interconnection. If approved, the public utility shall provide a written statement of final acceptance and cost reconciliation. Any applicant for a DG system that passes the commissioning test may sign a standard interconnection agreement and interconnect. If the public utility does not approve the interconnection, the applicant may take corrective action and request the public utility to reexamine its interconnection request.

(12) A standard interconnection agreement shall be signed by the applicant and public utility before parallel operation commences. **The standard interconnection agreement signed by the utility is to be provided by the utility to the applicant at the time of utility approval to interconnect.**

4. Setting DG Requirements of Spot or Secondary Network Service to National Standards in Wisconsin in PSC 119.20 (13)

Rationale

PSC 119.20 (13) states that the owner of a DG facility designed to operate in parallel with a spot or secondary network service shall provide relaying or control equipment that is rated and listed for the application and is acceptable to the public utility.

PSC 119.02 (Definitions) states: "Network service means 2 or more primary distribution feeders electrically connected on the low voltage side of 2 or more transformers, to form a single power source for any customer."

Extra work and uncertainty is imposed on interconnection applicants when acceptance of specific DG interconnection protection equipment, with spot or network service, is determined solely by the public utility. Without an engineering standard, DG equipment manufacturers are also faced with the extra work of developing separate devices and protection equipment to satisfy individual utility interconnection-safety requirements. Extra work is also imposed on utility staff to make engineering determinations that have already been vetted in national standards, with the potential risk of incurring legal liability.

The Federal Energy Policy Act of 2005 calls for state commissions to consider certain standards for electric utilities. Under Section 1254 of the act: "Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time."

It would simplify meeting the operation and safety best practices, for DG interconnection protection equipment with spot or network service, to base the engineering requirements on IEEE 1547 standards. The specific standard is IEEE Std 1547.6-2011 (Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks).

➔ **Proposal for Setting DG Requirements for Spot or Secondary Network Service to National Standards in Wisconsin**

Suggested changes to PSC 119 (changes in red)

PSC 119.20 (13) The owner of a DG facility designed to operate in parallel with a spot or secondary network service shall be **compliant with IEEE Std 1547.6-2011 (Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks). If the relaying and control equipment is not compliant with IEEE Std 1547.6-2011, it must be** acceptable to the public utility.

5. Cost-Effective DG Telemetry in Wisconsin in PSC 119.25 (3) (b) 6.

Rationale

A major topic of IEEE 1547 (Standards for Interconnecting Distributed Resources with Electric Power Systems) is the prevention of inadvertent or unintended islanding - a condition during which a DG facility remains in operation and energizes a local utility distribution load even though the local distribution system has been de-energized. However, there may be times when the DG penetration levels do contribute a substantial portion of electric power to a distribution feeder and implementation of utility-DG transfer-trip anti-islanding control may be warranted. Communications channel-based anti-islanding control allows disconnection decisions to be made by the utility's centralized SCADA system rather than by the DG controls.

IEEE 1547.3-2007 (Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems) describes functionality, parameters and methodologies for monitoring, information exchange and control for the interconnected distributed resources with electric power systems.

Current Situation:

PSC 119 (Definitions) defines "Telemetry" to mean transmission of DG operating data using telecommunications techniques. PSC 119.20 (General design requirements), section (14) states that for a Category 3 or Category 4 DG facility, the public utility may require that the facility owner provide telemetry equipment whose monitoring functions include transfer−trip functionality, voltage, current, real power (watts), reactive power (vars), and breaker status. PSC 119.25 (Minimum protection requirements), section (3) (b) states what other equipment shall be included in a Category 2, 3, or 4 DG facility.

PSC 119.25 (3) (b) (6) states the following: "Other equipment, such as other protective devices, supervisory control and alarms*, telemetry and associated communications channel*, that the public utility determines to be necessary. The public utility shall advise the applicant of any communications requirements after a preliminary review of the proposed installation."

The Problem:

Transfer-trip control arrangements involve significant complexity and also require a communication channel link. These communication links may be accomplished by dedicated telephone line, radio link, spread-spectrum radio, satellite link, T1 line, fiber-optic cable or other technologies. These communication technologies vary greatly in price for equipment and installation. Requiring expensive telemetry and communications channel types, when less expensive options are available, will have a significant impact on the time, cost, and uncertainty of a proposed DG project. The net effect of this requirement is to render some proposed DG projects to be uneconomical.

Best Practice:

There are cost-effective, IEEE 1547 compliant, devices commercially available that provide secure, long-range and fast transfer-trip telemetry alternatives for communications links. One of the security-based control strategies of these devices is to de-energize DG when the communications link is broken. This arrangement will assure positive control even in emergency situations due to storms, accidents or other non-standard conditions within a distribution system. The use of expensive DG telemetry types that are appropriate for very large merchant plants should be discouraged for DG facilities. Requiring least-cost telemetry solutions that meet transfer-trip functional requirements can have a significant positive effect on reducing the cost and installation time of DG facilities.

➔ Proposal for Updating the Requirement for DG Telemetry in Wisconsin

Suggested changes to PSC 119 (changes in red)

1. PSC 119.20 (14) For a Category 3 or Category 4 DG facility, the public utility may require that the facility owner provide telemetry equipment whose monitoring functions include transfer−trip functionality, voltage, current, real power (watts), reactive power (vars), and breaker status. **The requirement of any telemetry equipment by the public utility shall be prioritized on the criterion of least-cost that meets the current guidelines of IEEE Std. 1547.**

2. The following suggested change to PSC 119 clarifies that telemetry and associated communications channel are only required for Category 3 and 4 DG as specified in PSC 119.20 (14):
   PSC 119.25 (3) (b) states what other equipment that Category 2, 3, or 4 DG facility shall include. PSC 119.25 (3)(b)(6) states the following "Other equipment, such as other protective devices, supervisory control and alarms, telemetry and associated communications channel **(for Category 3 and 4 DG)**, that the public utility determines to be necessary pursuant to PSC 119.20(14). The public utility shall advise the applicant of any communications requirements after a preliminary review of the proposed installation."

6. Dispute Resolution and Referencing §196.26 Wis. Stats. (Complaint by consumers…) in PSC 119.40 (Right to appeal…)

Background Information
The specific process used for appealing, to the Public Service Commission of Wisconsin (PSCW), disputes relating to PSC 119 is not clear to many DG Facility applicants. *PSC 119.40 (Right to appeal)* states:

> *"The owner of a generating facility interconnected or proposed to be interconnected with a utility system may appeal to the commission should any requirement of the utility service rules filed in accordance with the provisions of this chapter be considered excessive or unreasonable, Such appeal will be reviewed and the customer notified of the commission's determination."*

However, the specific process used in making complaints to the PSCW is codified in Chapter 196.26 of the Wisconsin Statutes. *§196.26 Wis. Stats. (Complaint by consumers; hearing; notice; order; costs)* states:

> *(1) COMPLAINT. In this section, "complaint" means any of the following:*
> *(a) A complaint filed with the commission that any rate, toll, charge, or schedule, joint rate, regulation, measurement, act, or practice relating to the provision of heat, light, water, power, or telecommunications service is unreasonable, inadequate, unjustly discriminatory, or cannot be obtained.*
> *(b) A complaint specified in s. 196.199 (3) (a) 1m. b.*
> *(c) A complaint by a party to an interconnection agreement, approved by the commission, that another party to the agreement has failed to comply with the agreement and that does not allege that the failure to comply has a significant adverse effect on the ability of the complaining party to provide telecommunications service to its customers or potential customers.*
>
> *(1m) INVESTIGATION OF COMPLAINT. If any mercantile, agricultural, or manufacturing society, body politic, municipal organization, or 25 persons file a complaint specified in sub. (1) (a) against a public utility, or if the commission terminates a proceeding on a complaint under s. 196.199 (3) (a) 1m. b., or if a person files a complaint specified in sub. (1) (c), the commission, with or without notice, may investigate the complaint under this section as it considers necessary. The commission may not issue an order based on an investigation under this subsection without a public hearing.*
>
> *(2) NOTICE AND HEARING. (a) Prior to a hearing under this section, the commission shall notify the public utility or party to an interconnection agreement complained of that a complaint has been made, and 10 days after the notice has been given the commission may*

proceed to set a time and place for a hearing and an investigation. This paragraph does not apply to a complaint specified in sub. (1) (b).
(b) The commission shall give the complainant and either the public utility or party to an interconnection agreement which is the subject of a complaint specified in sub. (1) (a) or (c) or, for a complaint specified in sub. (1) (b), a party to an interconnection agreement who is identified in a notice under s. 196.199 (3) (b) 1. b., 10 days' notice of the time and place of the hearing and the matter to be considered and determined at the hearing. The complainant and either the public utility or party to the interconnection agreement may be heard. The commission may subpoena any witness at the request of the public utility, party to the interconnection agreement, or complainant.
(c) Notice under pars. (a) and (b) may be combined. The combined notice may not be less than 10 days prior to hearing.

(3) SEPARATE HEARINGS. If a complaint is made under sub. (1m) of more than one rate or charge, the commission may order separate hearings on each rate and charge, and may consider and determine the complaint on each rate and charge separately and at such times as the commission prescribes. The commission may not dismiss a complaint because of the absence of direct damage to the complainant.

(4) EXCEPTIONS. (a) This section does not apply to any rate, toll, charge or schedule of any telecommunications cooperative or unincorporated telecommunications cooperative association, except as provided under s. 196.205 or unless at least 5% of the customers of the telecommunications cooperative or association file a complaint with the commission that the rate, toll, charge or schedule is in any respect unreasonable, insufficient or unjustly discriminatory.
(b) This section does not apply to any rate, toll, charge or schedule of any small telecommunications utility except as provided under s. 196.215 (2). (c) Paragraphs (a) and (b) do not apply to a complaint specified in sub. (1) (b) or (c).

Referencing §196.26 Wis. Stats. (Complaint by consumers…) in PSC 119.4 (Right to appeal…) would provide clarification about the specific process used for complaints at the PSCW.

Also, formal complaints can be expensive and time consuming. Many states (including Illinois) include an informal dispute resolution process that can help avoid the need to pursue a formal complaint. See http://www.ilga.gov/commission/jcar/admincode/083/083004660001300R.html

Suggested changes to PSC 119.40 (changes in red)

a. **All parties shall attempt to resolve all disputes regarding interconnection promptly and in a good faith manner. A party shall provide prompt written notice of the existence of the dispute, including sufficient detail to identify the**

scope of the dispute, to the other party in order to attempt to resolve the dispute in a good faith manner.

b. **An informal meeting between the parties shall be held within 10 business days after receipt of the written notice. Persons with decision-making authority from each party shall attend such meeting. In the event said dispute involves technical issues, persons with sufficient technical expertise and familiarity with the issue in dispute from each Party shall also attend the informal meeting. If the parties agree, such a meeting may be conducted by teleconference.**

c. *The owner of a generating facility interconnected or proposed to be interconnected with a utility system may appeal to the commission should any requirement of the utility service rules filed in accordance with the provisions of this chapter be considered excessive or unreasonable* ***after informal meetings have been held****. Such appeal will be reviewed and the customer notified of the commission's determination* ***as defined in*** **§196.26 Wis. Stats.*"***

7. Refine Interconnection Insurance Requirements in PSC 119.05

Need for Insurance Review

All interconnection operations need to have insurance coverage to protect both the customer and the utility from unforeseen events. However, excessive insurance and documentation only serve to discourage customers from investing in renewable energy systems by needlessly increasing the complexity, time, and cost of their project. Additional insurance and adding a utilities name to the policy also increases the cost to the customer.

Questions to be answered

(1) Does current WI rule PSC 119.05 require additional insurance, including naming utilities as additionally insured, which is not necessary and do these requirements increase complexity, time, and transaction costs?

(2) Does the indemnification language still make sense from a complexity, time, and transaction cost perspective?

Current Situation

PSC 119.05 addresses **Insurance and Indemnification.**

(1) An applicant seeking to interconnect a DG facility to the distribution system of a public utility shall maintain liability insurance equal to or greater than the amounts stipulated in Table 119.05-1, per occurrence, or prove, financial responsibility by another means mutually agreeable to the applicant and the public utility. For a DG facility in Category 2 to 4, the applicant shall name the public utility as an additional insured party in the liability insurance policy.

Table 119.05-1 Information on required liability insurance

Cat. 1	$300,000 minimum liability insurance
Cat. 2	$1,000,000 minimum liability insurance, and the applicant shall name the utility as an additional insured
Cat. 3	$2,000,000 minimum liability insurance, and the applicant shall name the utility as an additional insured
Cat. 4	Negotiated, and the applicant shall name the utility as an additional insured

Assessment of question 1 addressing the need for additional insurance and naming the utility as additionally insured:

Table 119.05-1 only states that liability insurance is required in the minimum amounts shown. ***The rule does not indicate that additional insurance is needed.*** A related question might consider whether the amounts of insurance required are reasonable or whether the amounts need to be periodically adjusted due to inflation, experience, and risk factors.

Home insurance typically includes about $300,000 in liability. , so the current amount required for Class 1 does not seem detrimental to complexity, time, or cost.

Class 2 and 3 categories also seem to be within a reasonable range, compared to the California PGE and to IREC's insurance recommendation. A comparison is shown below:

Capacity	Wisconsin Insurance Requirement	California Insurance Requirement[8]	IREC Insurance Requirement (inverter)[9]	IREC Insurance Requirement (non-inverter)[10]
20KW-100KW		$1,000,000		
20 kW-200 kW	$1,000,000			
50 K-500 KW			$0	$500,000
>100 kW		$2,000,000		
>500 kW-2 MW			$1,000,000	
>200 KW-1 MW	$2,000,000			

The Class 4 comparisons of the Wisconsin rule to the California, New Jersey, and IREC liability insurance requirements are shown below:

Capacity	Wisconsin Insurance Requirement	California (PGE)Insurance Requirement	New Jersey Insurance Requirement[11]	IREC Insurance Requirement (inverter)	IREC Insurance Requirement (non-inverter)
>100 kW		$2,000,000			

[8] http://www.solarabcs.org/about/publications/reports/interconnection/pdfs/ABCS-07_studyreport.pdf

[9] http://irecusa.org/wp-content/uploads/2010/01/IREC-Interconnection-Procedures-2010final.pdf
[10] Ibid.
[11] http://www.pseg.com/home/save/solar/pdf/InterconnectionApplication-Level1.pdf

>1 MW-15 MW	Negotiated				
1 MW-5 MW				$1,000,000	
>2 MW			$2,000,000		
2 MW-5 MW					$2,000,000
>5 MW				$2,000,000	$3,000,000

The current rule for Wisconsin's Class 4 Distributed Generators may increase complexity, time, and cost because the amount of insurance is not specified and may take some time (and cost) to negotiate. A specified insurance requirement may reduce the complexity, time, and cost to determine insurance needs. Options could consider:

1. Developing insurance levels for inverter and non-inverter systems, as described in the IREC document.
2. Specifying a minimum liability level of $3,000,000, which is in range of other listed requirements and would likely be in the range of commercial insurance for an electrical generation project of this size (1 MW- 15 MW).

Listing utilities as additionally insured

The last part of PSC 119.05 (1) requires that the utility should be listed as additionally insured in the insurance form. This may be unnecessary as any insurance policies would protect other property if the customer was negligent. In addition multiple jurisdictions do not require this provision. A lot has changed since these insurance requirements were initially negotiated. In 2004, distributed generation was relatively uncommon and the risks were not known. Since then, there have been more than 200,000 distributed PV systems interconnected around the country without any known substantial damage caused to the utility grid. Therefore ***this requirement is unnecessary and should be dropped.***

Liability statement in PSC 119.05 (2)

(2) Each party to the standard interconnection agreement shall indemnify, hold harmless and defend the other party , its officers, directors, employees, and agents from and against any and all claims, suits, liabilities, damages, costs and expenses resulting from the installation, operation, modification, maintenance or removal of the DG facility . The liability of each party shall be limited to direct actual damages, and all other damages at law or in equity shall be waived.

This statement appears reasonable.

➔ **Proposal to Refine Insurance Interconnection Insurance Requirements**

Suggested changes to PSC 119 (changes in red)

PSC 119.05 **Insurance and Indemnification.**

(1) *An applicant seeking to interconnect a DG facility to the distribution system of a public utility shall maintain liability insurance equal to or greater than the amounts stipulated in Table 119.05-1, per occurrence, or prove, financial responsibility by another means mutually agreeable to the applicant and the public utility.*

Cat. 1	$300,000 minimum liability insurance
Cat. 2	$1,000,000 minimum liability insurance
Cat. 3	$2,000,000 minimum liability insurance
Cat. 4	**$3,000,000 minimum liability insurance**

FERC's language on Insurance:

"The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in the State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Transmission Provider, except that the Interconnection Customer shall show proof of insurance to the Transmission Provider no later than ten Business Days prior to the anticipated commercial operation date. An Interconnection Customer of sufficient credit-worthiness may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected."

Comment on FERC Requirement: The FERC language does not give any guidance on the amount of insurance required, which adds uncertainty and possible disagreements. **FERC requirements do not list utilities required to be named as additionally insured.**

8. Updates to DG Facility Interconnection Application and Agreement Forms in PSC-6027 R, 6028 R, 6029 R and 6030 R

Suggested changes to PSC 119 Interconnection Forms are needed to reflect the recommended changes to PSC 119. These changes are summarized below **(changes in red):**

Standard Distributed Generation Application Form (Generation 20 kW or less) - PSC-6027 R (03-04-04)

11. Site Plan Showing Location of the External Disconnect Switch, **if used.** (attach additional sheets as needed)

12. Liability Insurance. The Applicant, (Site Owner or Operator, if different) shall provide **proof of insurance, such as the declaration page,** demonstrating that this liability insurance is in place

Distributed Generation Interconnection Agreement (20 kW or less) - PSC-6029 R (04-19-04)

3. Interconnection Disconnect Switch.
The Public Utility may require that the Applicant furnish and install an interconnection disconnect switch, **if used,** that opens, with a visual break, all ungrounded poles of the interconnection circuit. The interconnection disconnect switch shall be rated for the voltage and fault current requirements of the DG Facility, and shall meet all applicable UL, ANSI, and IEEE standards, as well as applicable requirements of the Wisconsin State Electrical Code, Volume 2, Wis. Adm. Code Chapter Comm 16. The switch enclosure shall be properly grounded. The interconnection disconnect switch shall be accessible at all times, located for ease of access to Public Utility personnel, and shall be capable of being locked in the open position. The Applicant shall follow the Public Utility's recommended switching, clearance, tagging, and locking procedures.

5. Insurance.
Throughout the term of this Agreement, Applicant shall carry the following insurance:
A liability insurance policy that provides protection against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of Applicant's ownership and/or operation of the DG Facility under this Agreement. The limits of such policy shall be at least $300,000 per occurrence or prove financial responsibility by another method acceptable, and approved in writing, to Public Utility. The failure of the Applicant or Public Utility to enforce the minimum levels of insurance does not relieve the Applicant from maintaining such levels of insurance or relieve Applicant of any liability. Prior to execution of this Agreement applicant shall provide the Public Utility **with proof of insurance, such as the declaration page.**,

Distributed Generation Application Form (Greater than 20 kW to 15 MW) – PSC-6028 R (03-04-04)

11. Supplementary Information (attach additional sheets if needed)
(a) Provide one-line schematic diagram of the system:
(b) Control Schematics

(c) Site Plan: show major equipment, electric service entrance, electric meter, location of distributed generation and interface equipment, location of disconnect switch, **if used**, adjoining street name, and street address of distributed generation.

Distributed Generation Interconnection Agreement (20 kW to 15 MW) - PSC-6030 R (04-12-04)

3. Interconnection Disconnect Switch.

The Public Utility may require, **for Category 3 and 4 DG facilities**, that the Applicant furnish and install an interconnection disconnect switch that opens, with a visual break, all ungrounded poles of the interconnection circuit. The interconnection disconnect switch shall be rated for the voltage and fault current requirements of the DG Facility, and shall meet all applicable UL, ANSI, and IEEE standards, as well as applicable requirements of the Wisconsin Electrical Safety Code, Volume 2, Chapter Comm 16. The switch enclosure shall be properly grounded. The interconnection disconnect switch shall be accessible at all times, located for ease of access to Public Utility personnel, and shall be capable of being locked in the open position. The Applicant shall follow the Public Utility's recommended switching, clearance, tagging, and locking procedures.

4. Modifications to the DG Facility.

Applicant shall notify Public Utility of plans for any material modification to the DG Facility by providing at least forty (40) working days of advance notice for Category 2 or **forty five** (**45**) working days of advance notice for Categories 3 and 4. A "material modification" is defined as any modification that changes the maximum electrical output of the DG Facility or changes the interconnection equipment (e.g., changing from certified to non-certified devices or replacement of components with components of different functionality or UL listings). The notification shall consist of a completed, revised Application and such supporting materials as may be reasonably requested by Public Utility. Applicant agrees not to commence installation of any material modification to the DG Facility until Public Utility has approved the revised Application. The timetable for Public Utility's response to proposed material modification, after receiving proper notification, is described in Wisconsin Administrative Code § PSC 119.06 and shown below.

Category	Generation Capacity after Modification	Working Days for Public Utility's Response to Proposed Modifications
2	Greater than 20 kW to 200 kW	40
3	Greater than 200 kW to 1 MW	**45**
4	Greater than 1 MW to 15 MW	**45**

9. Line Extensions and Modifications for DG Facilities in Wisconsin in PSC 119.04 (8) and PSC 119.08

Rationale

The Current Situation and Problem:

The current administrative "Rules for Interconnecting Distributed Generation Facilities" (PSC 119) does not provide clear guidance for which standards will be used for electric utility line extensions and modifications for distributed generation facilities. The "Electric Service Extension" rules (PSC 113.1001) specifically state that "these standards shall not apply to the inter-connection of customer-owned generation facilities".

> *Subchapter X — Electric Service Extension*
> *PSC 113.1001 Purpose. The purpose of subch. X is to establish standards for electric utility service extension rules.* These standards shall not apply to the inter−connection of customer−owned generation facilities. *The primary objective of these standards shall be to provide for an equitable cost relationship between new customers and existing customers. The determination of an equitable relationship shall consider the effect of the extension rule on the environment, the utility's revenue requirement and the efficient use of electricity.*
> *History: Cr. Register, July, 2000, No. 535, eff. 8−1−00.*

Incongruously, despite the stated non-applicability of the electric service extension rules - found in PSC 113.1001 - to distributed generation facilities, a provision of the "Rules for Interconnecting Distributed Generation Facilities" (PSC 119) states that the costing principles for line extensions shall be assessed according to PSC 113.1005.

> *PSC 119.08 Fees and distribution system costs.*
> *(3) Costs for any necessary line extension shall be assessed pursuant to s. PSC 113.1005.*

Some of the issues related to line extensions and modifications are scattered in other PSC 119 provisions as follows:

> *PSC 119.04 Application process for interconnecting DG facilities.*
> *(8) The public utility shall perform a distribution system study of the local distribution system and notify the applicant of findings along with any distribution system construction or modification costs to be borne by the applicant.*
> *(9) If the applicant agrees, in writing, to pay for any required distribution system construction and modifications, the public utility shall complete the distribution system upgrades and the applicant shall install the DG facility within a time frame that is mutually agreed upon. The applicant shall notify the public utility when project construction is complete.*
>
> *PSC 119.08 Fees and distribution system costs.*

(2) The public utility may recover from the applicant an amount up to the actual cost, for labor and parts, of any distribution system upgrades required. No public utility may charge a commissioning test fee for initial start−up of the DG facility. The utility may charge for retesting an installation that does not conform to the requirements set forth in this chapter.

PSC 119.07 Easements and rights−of−way.
If a public utility line extension is required to accommodate a DG interconnection, the applicant shall provide, or obtain from others, suitable easements or rights−of−way. The applicant is responsible for the cost of providing or obtaining these easements or rights of way.
History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

However, some important and relevant provisions of the electric service extension rules of PSC 113 are not currently delineated for distributed generation facilities. The following proposal for changes in administrative rules for line extensions and modifications for DG facilities will bring coherence between how these provisions are addressed in PSC 113 and PSC 119. These changes provide some equanimity in the handling of costing issues and are not prescriptive of technical requirements.

- **Proposal for Changes in Administrative Rules for Line Extensions and Modifications for DG Facilities in Wisconsin**

Suggested changes to PSC 113 (changes in red)
Subchapter X — Electric Service Extension
PSC 113.1001 Purpose. The purpose of subch. X is to establish standards for electric utility service extension rules. These standards shall not apply to the inter−connection of customer−owned generation facilities **except as indicated in PSC 119**. The primary objective of these standards shall be to provide for an equitable cost relationship between new customers and existing customers. The determination of an equitable relationship shall consider the effect of the extension rule on the environment, the utility's revenue requirement and the efficient use of electricity.

Suggested changes to PSC 119 (changes in red)
PSC 119.04 (8) The public utility shall perform a distribution system study of the local distribution system and notify the applicant of findings along with any distribution system construction or modification costs to be borne by the applicant. **The public utility shall design extensions and modifications at the lowest reasonable cost. The facilities shall comply with accepted engineering and planning practices. The public utility shall engineer and estimate the cost of each three-phase extension based on reasonable current costs. Current costs may be estimated using job specific costs, average costs per foot or unit, or other costing method as appropriate.**

PSC 119.08 Fees and distribution system costs.
(1) Upon receiving a standard application form, the public utility shall specify the amount of any engineering review or distribution system study fees. Application fees shall be credited toward the cost

of any engineering review or distribution system study. The applicant shall pay the fees specified in Table 119.08, unless the public utility chooses to waive the fees in whole or in part.

(2) The public utility may recover from the applicant an amount up to the actual cost, for labor and parts, of any distribution system upgrades required. No public utility may charge a commissioning test fee for initial start−up of the DG facility. The utility may charge for retesting an installation that does not conform to the requirements set forth in this chapter.

(3) Costs for any necessary line extension shall be assessed pursuant to s. PSC 113.1005.

(4) The utility shall make refunds to a customer applicant who made a contribution for an extension when the utility makes an extension from the contributed extension to a second customer who does not require a contribution from the second customer (a non-contributed extension) pursuant to s. PSC 113.1007 and s. PSC 113.1006.

10. Defining the Categories of DG Facilities in Terms of Capacity in Wisconsin in PSC 119.02

Rationale

The Current Situation and Problem:

PSC 119 defines DG facilities into graduated size categories.

- "Category 1" means a DG facility of 20 kW or less.
- "Category 2" means a DG facility of greater than 20 kW and not more than 200 kW.
- "Category 3" means a DG facility of greater than 200 kW and not more than 1 MW.
- "Category 4" means a DG facility of greater than 1 MW and not more than 15 MW.

It is clear that kW and MW are power units. However, are these power unit "sizes" assumed to be the operating power output level of a generator, the maximum power output of a generator, the rated power output rating of the grid-interactive interface and protection system or some other rating? Adding to the lack of specificity, the word "capacity" is mentioned in the followings sections of PSC 119 in regard to the four categories of DG facilities: 119.01, Table 119.05−1, Table 119.06−1, Table 119.08−1 and 119.20 (12). The precise definition of the word "capacity" is missing from the definitions in PSC 119.

In practice, however, there has been some uncertainty about the exact meaning of these size ratings where the utility and applicant can have differing opinions about the definition. Uncertainty will have a negative impact on the proposed DG project in terms of equipment specification, time and cost.

Best Practice:

In the electric power industry, "capacity" commonly refers to an amount of electrical power delivered for which a generator, transformer, turbine, transmission line or other system is rated by the manufacturer. More specifically, "generator nameplate capacity" is usually used in the industry. "Generator nameplate capacity" is typically defined as the full-load continuous rating of a generator, prime mover, or other electric power production equipment and is measured in kilowatts (kW) or megawatts (MW). Installed generator nameplate capacity is usually indicated on a nameplate physically attached to a synchronous generator, induction generator or other type of generator. In the case of photovoltaic (PV) systems, where multiples of PV modules are combined to make up a system (array), the nameplate rating would be the sum of all PV module nameplate ratings making up the complete system, or the AC power rating of inverter, whichever is less .

➔ **Proposal to Define the Categories of DG Facilities in Terms of Capacity in Wisconsin**

Suggested changes to PSC 119 (changes in red)

PSC 119.02 Definitions. In this chapter:

(4) "Category 1" means a DG facility **having a capacity** of 20 kW or less.

(5) "Category 2" means a DG facility **having a capacity** of greater than 20 kW and not more than 200 kW.

(6) “Category 3” means a DG facility **having a capacity** of greater than 200 kW and not more than 1 MW.
(7) “Category 4” means a DG facility **having a capacity** of greater than 1 MW and not more than 15 MW.

(7-1) “Capacity” means the full-load continuous rating of a synchronous or induction generator or the AC power rating of an inverter, whichever is less, measured in kilowatts (kW) or megawatts (MW), and declared by the manufacturer or remanufacturer as the nameplate power rating.