U-15113

Staff Report on Net Metering and Electric Utility Interconnection Issues

October 1, 2007

Appendix 2

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Faster & Less Complex Interconnection Procedures
Staff is proposing to use the Interstate Renewable Energy Council's Model Interconnection Standards for Customer-Generator Facilities, Simplified Interconnection Procedures as a starting point for the workgroup. Any 10 kW and under generator interconnection that does meet the requirements for interconnection under these procedures would continue to be processed using the existing Under 30 kW generator interconnection procedures.

This set of Generator Interconnection Requirements has been modified by MPSC Staff. (The complete set of IREC Model procedures for all sizes of interconnections is available at the IREC website: http://www.irecusa.org/connect/modelrules.pdf)

Please review and comment on these proposed procedures.

MICHIGAN ELECTRIC UTILITY

Generator Interconnection Requirements

Qualified Inverter-Based Projects With Aggregate Generator Output 10 kW or Less

Table of Contents:

(a) Scope: This Generator Interconnection Requirements document outlines the process, requirements, and agreements used to install or modify generation projects for certified, inverter-based facilities with a power rating of 10 kilowatts (kW) or less on a utility's electric distribution system under certain conditions.

(b) **Standards for the Certification of Generators and Interconnection Equipment**: In order to qualify as "certified" for any interconnection procedures, generators shall comply with the following codes and standards as applicable:

1. UL 1741 Inverters, Converters and Controllers for Use in Independent Power Systems; and
2. IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems and IEEE 1547.1 Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.

(c) **Certified Equipment**: Interconnection equipment shall be considered certified for interconnected operation if the equipment has been tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous interactive operation with a utility grid and meets the definition for certification under FERC Order 2006.

(d) **General Technical Screening Criteria**

1. For interconnection of a proposed generator to a radial distribution circuit, the aggregated generation, including the proposed generator, on the circuit will 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 distribution system connected to a Customer bounded by automatic sectionalizing devices or the end of the distribution line.
2. The proposed generator, in aggregation with other generation on the distribution circuit, will not contribute more than 10 percent to the distribution circuit's maximum Fault Current at the point on the high-voltage (primary) level nearest the proposed Point of Common Coupling.
3. The proposed generator, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or Customer equipment on the system, to exceed 90 percent of the short circuit interrupting capability; nor is the interconnection proposed for a circuit that already exceeds 90 percent of the short circuit interrupting capability.
4. The proposed generator is interconnected to the utility distribution system as shown in the table below:

Primary Distribution Line Configuration	Interconnection to Primary Distribution Line
Three-phase, three-wire	If a three-phase or single-phase generator, interconnection must be phase-to-phase
Three-phase, four-wire	If a three-phase (effectively grounded) or single-phase generator, interconnection

	must be line-to-neutral

5. If the proposed generator is to be interconnected on single-phase shared secondary, then the aggregate generation capacity on the shared secondary, including the proposed generator, will not exceed 20 kilovolt-amps (kVA).
6. If the proposed generator is single-phase and is to be interconnected on a transformer center tap neutral of a 240-volt service, its addition will not create an imbalance between the two sides of the 240-volt service of more than 20 percent of nameplate rating of the service transformer.
7. The proposed generator, in aggregate with other generation interconnected to the distribution low-voltage side of the substation transformer feeding the distribution circuit where the generator proposes to interconnect, will not exceed 10 kW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission voltage level busses from the Point of Common Coupling).
8. The proposed generator's Point of Common Coupling will not be on a transmission line.
9. The generator cannot exceed the capacity of the Customer's existing electrical service.
10. No construction of facilities by the utility on its own system shall be required to accommodate the generator.

(e) **Special Screening Criteria for interconnection to distribution networks.** The screening criteria under this subsection shall be in addition to the applicable screens in subsection (d).

1. For interconnection of a proposed generator to a Spot Network circuit where the generator or aggregate of total generation exceeds 5 percent of the Spot Network's maximum load, the generator must utilize a protective scheme that will ensure that its current flow will not affect the network protective devices, including reverse power relays or a comparable function.
2. For interconnection of a proposed generator that utilizes inverter-based protective functions to an Area Network, the generator, in aggregate with other exporting generators interconnected on the load side of network protective devices, will not exceed the lesser of 10 percent of the minimum annual load on the network or 10 kW. For a photovoltaic Customer-Generator Facility without batteries, the 10 percent minimum shall be determined as a function of the minimum load occurring during an off-peak daylight period.
3. For interconnection of generators to Area Networks that do not utilize inverter-based protective functions or inverter-based generators that do not meet the requirements of (e)2 above, the generator must utilize reverse power relays or other protection devices and/or methods that ensure no export of power from the Customer's site including any inadvertent export (e.g. under fault conditions) that could adversely affect protective devices on the network circuit.

(f) **Screening Criteria and Process: Inverter-Based Generators Not Greater than 10 kW**

1. Application: Project Developer submits a completed application indicating which certified interconnection equipment the Project Developer intends to use. Within three days, Utility acknowledges to the Project Developer receipt of the application and notifies the Project Developer that the application is complete or incomplete. If the application is incomplete, the Utility shall provide written notice to the Project Developer

that the application is incomplete, and provide within 10 days of the initial receipt a written list detailing all information that must be provided to complete the application. The Project Developer will have 10 business days after receipt of the list to submit the listed information, or to request an extension of time to provide such information. Otherwise, the application will be deemed withdrawn. A Project Developer may pre-execute standard Interconnection Agreement and submit with application.

2. Applicable Screens: Screens (d)1, (d)5, (d)6, d9, (d)10. For interconnections to distribution networks, proposed facilities must also pass screen (e)1.
3. Time to process screens: Within 10 business days after the Utility notifies the Project Developer that the application is complete, the Utility shall notify the Project Developer whether the Project meets all the applicable screens above. If the Project fails one or more of the applicable screens, the Project Developer may request the application continue to be processed under the Interconnection Requirements for Projects with Aggregate Generator Output of Under 30 kW.
4. Approval: If a Project meets all of the applicable screens above, within three days the Utility shall send a partially executed Interconnection Agreement (or a fully executed Interconnection Agreement where the Project Developer has pre-executed the Interconnection Agreement).
5. A Project Developer that receives an Interconnection Agreement shall execute the agreement and return it to the Utility at least five business days prior to starting operation of the Project (unless the Utility does not so require or the Project Developer pre-executed the Interconnection Agreement). The Project Developer shall indicate the anticipated start date for operation of the Project. If the Utility requires an inspection of the Project, the Project Developer shall provide at least five business days notice to the Utility prior to the initiation of operations.
6. If a Utility does not notify a Project Developer in writing or by e-mail whether the interconnection is approved or denied within 20 business days after the receipt of an application, the interconnection shall be deemed approved. The 20 days shall begin on the date that the Utility sends the written or e-mail notice that the application is received.
7. Application fee: $100.

(g) **General Provisions and Requirements After Interconnection Approval**

1. The Project Developer is responsible for all construction of generator facilities and obtaining any necessary local code official approval (electrical, zoning, etc.).
2. The Project Developer conducts commissioning test pursuant to IEEE Standard 1547 and manufacturer requirements.
3. To assist Project Developers in the interconnection process, the Utility will designate an employee or office from which basic information on the application can be obtained through an informal process. Upon request, the Utility shall provide the Project Developer with all relevant forms, documents and technical requirements for filing a complete application for interconnection of generators.
4. If the Project complies with all applicable standards above, the Project shall be presumed to comply with the technical requirements of this rule. In such a case, the Utility shall not require a Project Developer to install additional controls (including but not limited to a utility accessible disconnect switch), to perform or pay for additional tests, or to purchase additional liability insurance (other than as set forth herein) in order to obtain approval to interconnect except as agreed to by the Project Developer.
5. Additional protection equipment not included with the certified generator or interconnection Equipment Package may be added at the Utility's discretion as long as

the performance of the Project Developer's equipment is not negatively impacted in any way and the Project Developer is not charged for any equipment in addition to that which is included in the certified Equipment Package.

6. Metering and Monitoring: As set forth in the Utility tariff for net metering.
7. A Utility that charges any fee other than the application fees set forth above shall provide the Project Developer with a bill that includes a clear explanation of all charges.
8. Once an interconnection has been approved under this rule, the Utility shall not require a Project Developer to test the Project.
9. A Utility shall have the right to inspect the Project before and after interconnection approval is granted, at reasonable hours and with reasonable prior notice provided to the Project Developer. If the Utility discovers the Project is not in compliance with the requirements of IEEE Standard 1547, and the non-compliance adversely affects the safety or reliability of the electric system, the Utility may require disconnection of the Project until it complies with this subchapter.

Attachment 1: Definitions

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

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

"IEEE standards" means the standards published by the Institute of Electrical and Electronic Engineers, available at www.ieee.org.

Attachment 2: Application for Qualified, Inverter-Based Generating Facilities Not Greater than 10 kW

The undersigned Project Developer submits this Generator Interconnection Application and $100 filing fee to interconnect a new Project to the Utility Electric System or to increase the capacity of an existing Project connected to the Utility Electric System. Please keep a copy for your records.

Project Developer

Name: ______________________________

Contact Person: ______________________________

Address: ______________________________

City, State, Zip: ______________________________

Telephone (Day): ______________________________

Telephone (Evening): ______________________________

Fax: ______________________________

E-Mail Address: ______________________________

Utility Customer Account Number: ______________________________

Contact (if different from Project Developer)

Name: ______________________________

Contact Person: ______________________________

Address: ______________________________

City, State, Zip: ______________________________

Telephone (Day): ______________________________

Telephone (Evening): ______________________________

Fax: ______________________________

E-Mail Address: ______________________________

Owner of the facility (include percent ownership by any electric utility): ______________

Project Information

Location (if different from above): ______________________________

Inverter Manufacturer: ______________ Model: ______________

Inverter Serial Number: ______________

Inverter Nameplate Rating: (kW) (kVA) (AC Volts) ____________

Single Phase _______ Three Phase _______

Prime Mover: Photovoltaic / Reciprocating Engine / Fuel Cell / Turbine / Other

Energy Source: Solar / Wind / Hydro / Diesel / Natural Gas / Fuel Oil Other (describe) __________

Is the equipment UL1741 Listed? Yes / No

If Yes, attach a copy of the manufacturer's cut-sheet showing UL1741 listing

Disconnect Type: Separate Manual Disconnect – Location: ___________________________________

(Meter Removal: If the Project Developer elects not to install a manual disconnect device accessible to Utility, the Utility shall not be liable when a service meter is removed to disconnect the generator thereby interrupting all utility electric service to the Customer site.)

Estimated Installation Date: _____________ Estimated In-Service Date: ____________
These Interconnection Requirements are available only for inverter-based Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements.

List components of the Small Generating Facility Equipment Package that are currently certified:
Equipment Type Certifying Entity
1.
2.
3.
4.
5.

Project Developer 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 Interconnection of a Generating Facility 10 kW or Smaller [[*and return the Certificate of Completion when the Project has been installed*.]]

Signed: ____
Title: Date:

Contingent Approval to Interconnect the Project

(For Company use only)
Interconnection of the Project is approved contingent upon the Terms and Conditions for Interconnection of a Generating Facility 10 kW or Smaller [[*and return of the Certificate of Completion*.]]

Company Signature: ____
Title: Date:
Application ID number: __________________

Company waives inspection/witness test? Yes___No___

[[*Note: Where use of a Certificate of Completion is not agreed to by state code officials, the text in brackets should be stricken*.]]

Attachment 3: Standard Form Interconnection Agreement

1.0 **Construction of the Facility**
The Project Developer may proceed to construct (including operational testing not to exceed two hours) the Project when the Utility approves the Application and executes this Interconnection Agreement.
2.0 **Interconnection and Operation**
The Project Developer may operate the Project and interconnect with the Company's electric system once all of the following have occurred:
2.1 Upon completing construction, the Project Developer will cause the Project to be inspected or otherwise approved 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 Witnessed the satisfactory Commissioning. All witnessing and inspections must be conducted by the Company, at its own expense, and returned the Certificate of Completion [[*if used*]]; or
2.3.2 If the Company does not schedule an inspection of the Project, the witness test is deemed waived (unless the Parties agree otherwise); or
2.3.3 The Company waives the right to inspect the Project.
2.4 The Company has the right to disconnect the Project in the event of improper installation. Written documentation of explaining why the project is improperly installed will be provided no later than at the time of disconnection.
3.0 **Safe Operations and Maintenance**
The Project Developer shall be fully responsible to operate, maintain, and repair the Project 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 metering equipment of the Project at all times. The Company shall provide reasonable notice to the Project Developer when possible prior to using its right of access.
5.0 **Disconnection**
The Company may temporarily disconnect the Project upon the following conditions:
5.1 For scheduled outages upon reasonable notice.
5.2 For unscheduled outages or emergency conditions.
5.3 If the Project does not operate in the manner consistent with these Terms and Conditions.
5.4 The Company shall inform the Project Developer 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 Project Developer is not required to provide general liability insurance coverage as part of this Agreement, or any other Company requirement**.** Though there is no specific insurance requirement associated with this Agreement, it is incumbent upon the Project Developer to inform their property insurance company of the addition of the electric generating equipment and make certain that their facilities are adequately insured against all potential claims.
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 Project Developer**

By providing written notice to the Company.

9.2 **By the Company**

If the Project fails to operate for any consecutive 12 month period or the Project Developer 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 Project Developer to disconnect the Project.

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 Project to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

Project Developer acknowledges having read the terms and conditions of this Interconnection Agreement.

PROJECT DEVELOPER	[**Utility Name]**
By: ______________________________ (Signature)	By:____________________________________ (Signature)
Printed Name: ______________________	Printed Name:___________________________
Title:______________________________	Title: __________________________________
	Effective Date:__________________________

Attachment 4: Certificate of Completion

[[*See note below*]]

Installation Information Check if owner-installed ☐
Project Developer: ________________________ Contact Person: ______________________________________

Mailing Address: ____

Location of Project (if different from above):

____

City: _____________________________________ State: ______________________ Zip Code: __________

Telephone (Daytime): ________________________ (Evening): ______________________________________

Facsimile Number: ___________________________ E-Mail Address: __________________________________

Electrician:
Name: ____

Mailing Address: ____

City: _____________________________________ State: ______________________ Zip Code: __________

Telephone (Daytime): ________________________ (Evening): ______________________________________

Facsimile Number: ___________________________ E-Mail Address: __________________________________

License number: ___________________________________
Application ID number: ____________________________

Electrical Inspection:
The system has been installed and inspected in compliance with the local Building/Electrical Code of _____
________________________________ (Appropriate governmental authority)
Signed (Local Electrical Wiring Inspector, or attach signed electrical inspection):
(*Note: Local procedures may differ on how to process approvals from local electric inspection officials*)

Name (printed): ____________________________________ Date: ___________

Utility (Utility) waives Witness Test? Yes ☐ No ☐

Utility Signature: __________________________________

Title: _______________________________

Date: _______________________________

Final Approval of Interconnection Agreement

The Certificate of Completion has been received and final approval to interconnect the Project is granted under the Generator Interconnection Requirements.

Utility Signature: ___________________________________ Title: ________________ Date: ______________

[[*Note: This certificate may be useful where the state has received agreement from local code officials to use this standard form. Where no such agreement has been obtained, local code officials may be unwilling to sign this form as it is not typically used in their approval process and some officials have shown a* *reticence to sign an unknown form. In those cases, this certificate should be supplanted with evidence of local code official approval as is the current local practice.*]]

10 kW and Under Draft Standards Revisions

Incorporating the new procedures requires formal rulemaking. Staff has prepared updated Interconnection Standards Rules Language for Rules 3 and 6. Please review and provide comments on the proposed rule revisions.

New language is noted in red underline text.

R 460.483 Technical criteria.

Rule 3. (1) The interconnection procedures shall specify technical, engineering, and operational requirements that are suitable for the electric utility's distribution system. The procedures shall include provisions that apply specifically to a project that designates some or all of its electrical output for sale to an electric utility or a third party.

(2) The interconnection procedures shall make provisions that are appropriate for the size and capacity of a project as they affect the technical and engineering complexity of the interconnection. The procedures shall include a distinct set of requirements for each of the following project capacity classifications:

(a) Qualified, inverter-based projects, 10 kW or less.
(b) Less than 30 kilowatts.
(c) Thirty kilowatts or more, but less than 150 kilowatts.
(d) One hundred and fifty kilowatts or more, but less than 750 kilowatts.
(e) Seven hundred and fifty kilowatts or more, but less than 2 megawatts.
(f) Two megawatts or more.

(3) If the voltage at the electrical connection is comparable to the electric utility's transmission voltages, but the electric utility's facilities are classified as part of its distribution system for jurisdictional purposes, such as a radial line, the project shall not be subject to the interconnection procedures approved under these rules. The interconnection shall instead comply with analogous federal energy regulatory commission standards.

History: 2003 MR 18, Eff Sept. 23, 2003.

R 460.486 Interconnection deadlines.

Rule 6. (1) The interconnection procedures shall set deadlines for processing an application filed by a project developer, achieving major milestones, and completing the interconnection and shall preclude undue delay. The deadlines shall ensure that the period from the date that the project developer files a complete application to the completion of all of the electric utility's obligations for interconnection shall be no longer than the following for each project capacity classification:

(a) Qualified, inverter-based projects, 10 kW or less 20 business days
(b) Less than 30 kilowatts 2 weeks
(c) Thirty kilowatts or more, but less than 150 kilowatts 4 weeks
(d) One hundred and fifty kilowatts or more, but less than 750 kilowatts 6 weeks
(e) Seven hundred and fifty kilowatts or more, but less than 2 megawatts 12 weeks
(f) Two megawatts or more 18 weeks

(2) Delays that are the responsibility of the project developer shall not be included in determining compliance with the deadlines imposed in subrule (1) of this rule.

(3) Delays that are solely attributable to time lapsed while an electric utility is diligently seeking to secure a necessary easement, right-of-way access, or other change in property rights or comply with governmental permitting or zoning requirements shall not be included in determining compliance with the deadlines imposed in subrule (1) of this rule.

History: 2003 MR 18, Eff Sept. 23, 2003.

April 16, 2007 Comments

Under 10 kW Net Metering & Interconnection Procedures Workgroup

Faster & Less Complex Interconnection Procedures

Staff Draft Interconnection Procedures Document
Staff Draft Interconnection Standards Revisions Document

Net Metering

Staff Draft Net Metering Proposal

Comment Summary

Commenter Name | Page Number

Steve Collini

Julie, Brian

I put into service an inverter based 3k wind system in 1999. At that time the utility (Consumers Energy) required any excess generation sell back to be classified as a NUG with exoribant costs to qualify. I was forced to use a large battery bank for storage purposes. The cost of batteries, maintenance, etc. makes this type of system not very user friendly for any one considering alternate energy. I applaud the efforts to make things much simpler. This leaves me with a dilema though. In 1999 I bought a very high end inverter with the safegaurds for utility interconnection. The inverter is one of the most expensive parts of any system so one does not want to replace them if not absouletley necessary. The proposed rules use the IEEE 1547 standard. This standard was developed after the manufacture date of my inverter, so there is no way to get my inverter to comply with the standard. The manufacturer of my unit is Trace engineering, Model # SW4048. Trace has since been bought by a company called Xantrex and they continue to support the product. My question would be is there any way in the ruling to incorporate equiptment that is known as safe to use in interconnections but was manufactured prior to the IEEE 1547standard? I've sent all my inverter specs to Consumers Energy to try and get an answer from them, about 3 weeks ago and haven't heard back yet. It would be very nice if the rules could be made to adress this type of situation.

Thank You
Steve Collini
1290 Harold Ave.
Roscommon, MI 48653
989-821-5900
steve.collini@charter.net

<u>David C. Tarsi PE</u>

Dear Sir,
I live in the western part of the upper peninsula of Michigan in the northwest corner of Iron county. I live off grid and have a 4.3KW set of solar panels. My home is a standard home and even in this remote area of Michigan I get almost 95% solar coverage. Who says solar does not work in Michigan. I am a retired engineer from Consumers Energy and understand the workings of a utility system. ***I believe we should not stop at net metering.*** This just does not offer the investment opportunity to the individual. They can only defray their yearly electric load. ***When you are on the grid, installing either a solar system or a wind generation system, this just does not even come close to the economics of service from the grid.*** Its better and cheaper to buy green energy through the utility companies and still participate in lowering our consumption of fossil fuels. As an example, I have reduced my dependency of over 1400 gallons of propane per year through solar. I hope to increase this when I install a solar hot water system this year. However, my electric system has cost me near $15,000. ***How can we expect the average to invest $10,000 to $20,000 to just eliminate their electric draw from the utility.*** Solar and wind generation costs have really gone up in the last two years. The European demand. What we need is the opportunity to invest in a renewable generation system that can effectively produce an offset to the initial capital cost. Of course one way is to have state and federal rebates, but the existing federal system is a weak attempt to promote an incentive to reduce a dependency on fossil fuels. ***The real Michigan incentive is to promote a fair system of energy sell-back to the utility.*** Such a system would provide a better way for one to offset costs. The equipment today provides for a safe inter-connect with the utility. They make grid-tie inverters that immediately disconnect themselves in the event of a loss of system. ***A fair system will provide a reasonable rate of sell-back KWH and at the same time not overload the dispersed generation with unreasonable costs in disconnect equipment costs.*** I truly believe the utilities can pitch in and work through different operational and maintenance procedures that would allow for more of these connections. It is just a different set of problems. ***I believe if we are going to make headway in promoting the use of renewable resources, we must solve these problems.***
I would appreciate any status you can provide or any other information you would like from me.

David C. Tarsi PE
dtarsi@sbcglobal.net
906.367.9251

Tom Basso
National Renewable Energy Laboratory

-----Original Message-----
From: Basso, Thomas [mailto:Thomas_Basso@nrel.gov]
Sent: Monday, April 02, 2007 3:53 PM
To: Stanton, Thomas S (DLEG)
Cc: bwjohnson@acninc.net
Subject:

Tom,

See below for background/up-to-date approach for interconnection of distributed resources, especially in that is the approach to 10 kW and less.

Let me know if you have questions on below.

Brad Johnson, NREL contractor, and I have been involved with various state activities for interconnection (not necessarily for rate design/tariff activities - however, separately, Brad has, and continues to be involved with tariff/rate design issues).

Generally, states have been separating "net metering" and "interconnection requirements/procedures/agreements" and "tariff issues" and RECs. Generally, net metering by definition simply means in a colloquial sense "run the meter backwards."

It seems the net metering guidelines you are proceeding under get fairly complex (unduly complex?) when you (state legislation?) start bringing rate design and RECs into "net metering" arena. The basic philosophy of net metering is simplicity. Perhaps the standard term/definition of "net metering" needs to be addressed/clarified for your purposes/approach. It appears that in one fast-track rule-making you are addressing much more than net metering. That appears as an interesting problem(s) but maybe for instance, opting as a net metering customer means giving up potential RECs.

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At March 22, 2007 MD Interconnection working group meeting unanimous consensus was reached by the stakeholders for new statewide interconnection rules and standard interconnection agreements. These rules and agreements reflect enhancements of the MADRI model and draw heavily from recent use of the MADRI model in Pennsylvania and Oregon. Highlights include the following:

1) A provision for expedited review for "field approved" interconnection equipment in addition to "certified equipment". (To become field approved, identical interconnection equipment must have been previously approved by an EDC under a study process). What this means is that a 250 kW micro turbine would qualify for expedited review, even if it did not have an inverter or a UL listing, if it used identical interconnection equipment already approved by the utility.

2) A provision that small generators up to 10 MW qualify for expedited review if they do not export power (50kW if they connect to area networks)

3) Technical requirements based on IEEE 1547, no exceptions and no additions.

4) Adherence to the requirements for <10kW systems that were developed by FERC with no changes to the review timelines

5) Agreement to use standard application forms and interconnection agreements throughout the entire state. There was considerable debate over the details of these documents. From my perspective, final forms and agreements being sent to the Commission for approval strike a fair and equitable balance between the interests of small generators and utilities.

The Working Group plans to issue its report to the MD Commission along with the final version of the documents by April 1. The MD Commission is expected to issue its order (hopefully a favorable one) by August. I will provide a copy of the working group report and a link to the final documents when they become available in a week or so.

Following is a brief summary of the 4 Levels of review that the Working Group developed (the first 3 are expedited):

Level 1 <10kW Expedited Review . These systems are inverter based and must be tested to IEEE and UL standards by a nationally recognized test laboratory. Household photovoltaic systems are an example of the type of small generator that is expected to qualify for Level 1 expedited review.

Level 2 - **10kW to 2 MW Expedited Review.** These systems must use equipment approved by a nationally recognized testing laboratory or must have been previously approved by an electric utility under a study process (field approval) .Systems in this size range do not have to be inverter based and are expected to use a variety of technologies including, photovoltaics, reciprocating engines, micro turbines, fuel cells, small wind generators and combined heat and power.

Level 3 - 10kW to 10 MW Expedited Review . These systems qualify for expedited review if they use special equipment to ensure they will not export power from the customer premises on to the electric distribution system. The vast majority of small generators that qualify for review under this category are expected to be standby generator facilities that interconnection at distribution system voltages and operate in parallel for more than 100 milliseconds. Net metered small generators are not be eligible for a Level 3 Review.(<50kW systems using lab certified equipment connecting to area networks, also qualify for expedited review under Level 3).

Level 4 - 2MW to 10 MW Study Process. Small generators that do not qualify for expedited review or have not been accepted under an expedited review already conducted will be evaluated under the procedures spelled out in this category. Because the small generators reviewed in this category are larger and are expected to use non-standardized interconnection equipment, there needs to be a more in-depth evaluation of the potential impacts of the small generator on the electric distribution system. For this reason, reviews conducted under a Level 4 evaluation are expected to be more costly and are expected to take more time. distribution network.

-----Original Message-----
From: Mansueti, Lawrence [mailto:Lawrence.Mansueti@hq.doe.gov]
Sent: Thursday, March 22, 2007 11:42 AM
To: Hoffman, Patricia; DeBlasio, Dick (NREL); Lippert, Alice; pielli.katrina@epa.gov; Miles Keogh; Lightner, Eric; Bindewald, Gilbert; Rich Sedano; Brad Johnson
Subject: EE/OE statement of best practices on DG interconnection

As posted the other day at EE's solar page of http://www1.eere.energy.gov/solar/

Attached…. <<doe_interconnection_best_practices.pdf>>
Respectfully, Tom Basso; thomas_basso@nrel.gov
Voice (303) 275-3753; FAX (303) 275-3835
T. Basso: NREL Distribution and Interconnection R&D;
IEEE Secretary SCC21, & 1547 series;
IEC/USNC/TAG/TC8 Technical Advisor & Administrator
NREL Thomas S. Basso MS1614
1617 Cole Blvd.
Golden CO 80401-3393
National Renewable Energy Laboratory http://www.nrel.gov/eis/activities.html
Distributed Energy and Electricity Reliability http://www.nrel.gov/programs/oeea.html
DOE Office of Electricity Delivery and Energy Reliability http://www.electricity.doe.gov

Richard Sloat

Greetings Brian,

The biggest draw back to the net metering issue is the disparity in credits i.e. that Michigan residents who want to interconnect to the grid can only expect to receive 25% discount (being charged $0.10/kwh for energy being created by the utility company and only getting reimbursed $0.025/kwh for the energy being created by themselves).

If this country wants to be serious about energy independence a one to one payback e.g. if a persons charge is $0.10/kwh by the utility company, the utility company should be charged $0.10/kwh for the energy produced by an individual espically when the utility company charges an additional 38% for "green energy" used by an individual.

Lets get going. I wouldn't worry so much about the utility companies making a profit, lets think more about having individuals creating clean renewable energy.

Sincerely,

Richard Sloat
223 8th Ave.
Iron River, Mi., 49935
(906) 265-0751

Joshua Barclay

I am strongly in favor of the proposed net-metering guidelines primarily because of their simplicity. Simple interconnection policies could make Michigan a haven for those wishing to produce clean, renewable energy. Clear equipment guidelines, simplest metering requirements, and a real net-metering approach make the entire process easier and cheaper for all participants, and make Michigan more attractive to new-energy-economy entrepreneurs, innovators and investors.

Prior to these new proposed guidelines, DTE's "net-metering" billing policy was so complex, I was still unable to understand how it worked after a full half-hour explanation from a very helpful and friendly engineer at DTE (I'm no math slouch either-I teach university level physics). I was confounded by why the interconnection process and billing formula needed to be so difficult, and why anyone would want to discourage me or anyone from making non-polluting, locally-harvested energy. This new proposal is certainly a breath of fresh air, and I mean that literally.

Augmenting the grid with a widely decentralized system of small PV and wind systems dotting the countryside has only advantages. It will increase the efficiency of the grid by lowering line-loss. Peak demand times neatly coincide with the highest power production of PV. Terrorists can't shut down our power grid if it's decentralized. Pollution is reduced. And we don't have to send dollars out of state, nor transport coal or uranium in--we get to power Michigan with local sunlight and wind delivered free, right to our door.

We are inevitably entering a regime where net carbon emissions will be limited-either legislatively, or by technologies competing to bring the world cleaner and safer energy. Michigan could propel itself to the leading edge of this new economy and technology. To do so, we must present clear advantages to the new energy economy entrepreneurs and innovators who could make Michigan a leader rather than a laggard.   We must learn from the mistakes of the big three, who not heeding the global demand for lowering carbon emissions, have been surpassed by carmakers that do.

To attract the business of the future, Michigan must compete with New Jersey rebating $4.40 per watt for builders of PV systems, and Wisconsin where We Energies will buy PV production for 22.5 cents/kwh. The proposed net-metering guidelines are a great start, but we need to go farther to encourage clean energy if we truly want Michigan to be a leader in the economy of the future.

Joshua Barclay
Whitmore Lake, MI

Mel L Barclay

We have recently built a 3.2 KW sun-tracking photovoltaic device along side our home.

The construction was not particularly difficult.

We make a lot of clean, non-polluting electrical energy of which we use only a portion.

The technology for converting DC to AC is mature and the logical processes performed in the intertie curcuitry make the possibility of islanding remote.

Our system works now and the meter sometimes runs backwards. Why do we need two additional meters ?

Our system shows how simple it could be to develop distributed power production given the right incentives.

The power industry should stand aside as it will facilitate these developments. They benefit as well by having more clean electricity to sell.

We should be sure we have learned all the lessons of Carterfone.

Mel L Barclay
Ann Arbor, MI

Chris Coon
Sustainable Systems, Inc.

Hi Julie and Brian-

Thanks for your work on these interconnection and netmetering procedures.

Re: DRAFT Proposal for Simplified Net Metering Program for Inverter-Based Systems 10 kW or Less

Looks good. Two considerations:

1.) I assume that the "minimum monthly fixed charge" referred to in number 4 will be based on rate information that will be examined carefully by MPSC staff to ensure it does contain major extraneous costs.

2.) Since the next level of interconnection / netmetering agreements is 30 - 150 kW, what rules will apply to a 12, 20, or 25 kW inverter-based system?

Re: Generator Interconnection Requirements ... Inverter-Based ... 10 kW or Less

Within the limits of my technical understandings of the implications of the interconnection procedures, it looks okay. I have been attempting to get Bob Pratt to examine these in detail, as he worked for DTE for many years dealing with the issues of interconnection of solar systems. I defer to him and hope that he comments on the interconnection requirements.

Thank you again for your work on these issues.

Sincerely,
Chris Coon
Solar Contractor
Sustainable Systems, Inc.
11994 Pleasant Lake Rd, Manchester, MI 48158
< sustainablesystems@ic.org >
734-428-9249

Don Lee
Independent Biodiesel, LLC

Julie and Brian,

I'm a student in the Master's of Management/Sustainable Business program at Aquinas College. I currently own a building at 700 Wealthy in Grand Rapids where I'm attempting to justify the cost of a carbon-emissions free energy system for my building. To this end I have been researching the implementation of a combination solar PV and thermal system for my facility. I would like to thank you for your effort to create a more fair and less complicated process for consumers to utilize renewable energy. I would like to add some points to the conversation.

The optimal outcome is the use of solar electricity to offset the costs of both the capital investment required for solar equipment, and the external costs of pollution, especially greenhouse gas emissions. Currently there is inequity between the natural gas and electric utilities and the consumer/producer of solar electricity. Presently in Michigan, there is no penalty associated with the external costs of extraction and consumption of fossil fuel-derived electricity and no method of "evaluating competing resources in which the most environmentally disruptive resource (a new coal plant) under the most unfavorable circumstances" creates external costs. (National Academy of Sciences, et al p. 709)

Monetary incentives are low as net metering, (the process of returning solar power that is generated by consumers to the grid) is currently difficult and cost prohibitive. A customer purchasing power from Consumer's Energy will pay an application fee of $100 to enroll in the program. In addition, the customer must complete and send to Consumers Energy the Net Metering Program application to ensure the proper metering configuration is installed, which will enable the customer to receive "Net Excess Generation Credits." After Consumers Energy has completed the interconnection study and has approved the proposed interconnection and net metering project, the customer will be required to enter into an 'Interconnection and Operating Agreement.' The customer is responsible for any costs associated with the interconnection." (http://www.consumersenergy.com/welcome.htm) It's not clear what these "costs" are.

Neither is it clear how much the consumer can expect to receive for electricity that is returned to the power company other than to say that it is defined as a "Net Excess Generation Credit. "Net Excess Generation (NEG) is the amount of electricity generated by a Net Metering participant using a renewable energy source, in excess of the customer's own electric metered use in any billing month. "One NEG Credit equals the Energy Charge portion of the Power Supply Charges – of one kilowatt-hour of electricity as shown on the customer's rate schedule, including the associated Power Supply Cost Recovery, but excludes Surcharges." (http://www.consumersenergy.com/welcome.htm)

It is difficult to determine a timeframe to recover the cost of installing a solar PV system. What is the current cost of a kWh of electricity? Why isn't the consumer able to sell that electricity back to Consumer's Energy at an equitable rate? Other considerations for cost include times of peak power output (returning energy to the grid). "…the peaking units, those generating facilities fired up only during the peak periods produce electricity at a much higher marginal cost than do base-load plants, those fired up virtually all the time. Peaking units are typically cheaper to build than base-load plants, but they have higher operating costs." (National Academy of Sciences, et al p. 709) Power returned to the grid during peak operating hours should therefore be eligible for a premium (higher) rate of return. During off peak hours or low sunlight and night time operation when demand is lower and while solar powered units are either not functioning or functioning at diminished capacity and the consumer is drawing energy from the grid, peak and non-peak rates are applicable. To be fair these rates should not be unilateral in favor of utilities, "Since renewable energy and conventional energy are physically indistinguishable, both are sold in the energy market at the same price." (Tietenberg p. 153)

There are incentives for utilities to provide equitable compensation for solar energy producers/consumers during peak periods because "slowing the growth in peak demand may delay the need for new, expensive capacity expansion" (Tietenberg p. 152) by transferring capital costs directly to consumers and reducing the higher marginal costs of peak period energy production. If there is an "environmental adder" (National Academy of Sciences, et al p. 709) for example "New York adds 1.4 cents per kilowatt-hour to the estimated cost of electricity produced from fossil fuel sources to account for the various negative environmental effects." (Tietenberg p. 153) The period of time required by the consumer to recoup those dollars is decreased as the cost of the externality (greenhouse gas emissions) are considered. This will also provide increased demand for renewable energy and bring capital costs down.

In summary, the cost of energy provided from sources that create emissions should have the external costs of greenhouse gas emissions associated with them in order to make renewables more competitive. The benefit to the consumer should also include the substitution of solar electric for natural gas and an “environmental adder” would accomplish that. Investment in solar energy equipment equates to the consumer providing dollars for capital improvement of a utility owned power system which diminishes peak output and reduces costs for utilities. Based on this assertion, the consumer should not be subject to enrollment or metering fees. Additionally, the consumer should receive equitable consideration in the market for the energy they produce.

“Emerging markets for clean technologies could create millions of new American jobs. It’s the single biggest global economic opportunity on the horizon.”
- Democratic Congressman Tom Udall, New Mexico (*Outside,* February 2007)

References

Panel on Policy Implications of Greenhouse Warming, National Academy of Sciences, National Academy of Engineering, Institute of Medicine. Policy Implications of Greenhouse Warming: Mitigation, Adaptation, and the Science Base. The National Academies Press, 1992.

Tietenberg, Tom. Environmental Economics and Policy. 5th ed. Boston: Pearson Education, Inc, 2007.

Consumers Energy. Search 'Net Metering'. n.d. 7 Apr. 2007
<http://www.consumersenergy.com/welcome.htm>.

Best Regards,

Don Lee
Independent Biodiesel, LLC
--
Aude Sapere
“Dare to Know”

Independent
Biodiesel

Lary Bannasch
<u>Great Lake Solar</u>

Hi Julie and Brian

As a new Michigan Small Business I'm pleased to see the focus on less than 10kW net metering Workgroup

As a start up supplier of BIPV Grid Tied Systems to Michigan residents having this focus will be helpfull to all (residents, installers and suppliers)

thank you for your efforts

Lary Bannasch
Great Lake Solar
810 895 1141

MICHIGAN REGULATED ELECTRIC INDUSTRY

MICHIGAN REGULATED ELECTRIC INDUSTRY COMMENTS ON MPSC STAFF INTERCONNECTION AND NET METERING PROPOSALS

These informal comments are submitted by the Michigan Electric and Gas Association on behalf of Michigan regulated electric utilities including MEGA members, the electric distribution cooperatives, Detroit Edison and Consumers Energy. The MPSC Staff circulated proposals for consideration by the "Under 10 kW Net Metering and Interconnection Procedures Workgroup" regarding (1) faster and less complex interconnection procedures, and (2) net metering, with draft documents containing an initial proposal. The electronic notice of the proposals requested comments by e-mail to the Staff with a deadline of Monday, April 16, 2007. The participating regulated electric utilities established a group to coordinate these responses, referred to here as the "Industry Group". These comments reflect the initial joint position of the Industry Group, recognizing that this is part of a working group process with opportunity for further discussion and participation as the informal workgroup procedures continue.

These comments are organized based on the framework of the Staff proposals, with headings adopted based on the proposals. Except where indicated for general Industry comments, the headings and bold language in subheadings below correspond to the order of items in the proposals. The industry comments are developed for each item, without repeating the entire provision in the proposal.

A. GENERAL INDUSTRY COMMENTS

The following comments are directed to the overall process of considering changes in the interconnection and net metering rules and procedures.

1. The working group is just being formed and there have been no meetings to discuss procedures for the small projects. Development of any new procedures is supposed to occur through a working group effort. This response should be part of the framework for discussion at future workgroup meetings.

2. The MPSC Staff (Staff) proposes to start with a model procedure developed by a renewable energy group, Interstate Renewable Energy Council (IREC). The IREC model is a 52 page document described as a compilation of best practices from various sources, with 11 sections and 8 attachments. Staff modified the IREC document to 13 pages and the working group should be given an explanation of why the IREC document is a better starting point than the Michigan procedures with which interested parties are already familiar. There should also be a review and explanation of the specific changes from the original IREC compilation.

3. All determinations <u>must</u> give primary consideration to safety of utility workers and the public. Measures that call for deemed approvals or presumed acceptance must be avoided. The procedures should not create any expectation or impression that projects can be energized without the necessary communication among all parties and appropriate testing.

4. The interconnection rules and related procedures were revised in 2003. These provisions continue to be applied and while there have been developer complaints and varying issues for some projects, there is no indication or finding that

any specific item of the current procedures is functioning as a barrier to development of projects. The pace of development is influenced by many factors, including the degree of interest of customers in generating electricity, the cost of generating equipment, cost-benefit analysis and the level of financial incentives or subsidies. The workgroup process should avoid any "rush to judgment" of changes based on a few complaints because there are indeed projects achieving successful interconnection, as reported in Case No. U-15113. There is time to do this right and avoid measures that will lead to further controversy and calls for revision.

5. A net metering consensus policy was approved by the Commission on March 29, 2005 in Case No. U-14346, implemented through tariff filings that year. The approved net metering policy contained time provisions for duration and the Commission called for an evaluation through the Michigan Renewable Energy Program (MREP) after the fourth year (in 2009). This would allow a reasonable study period based on actual results over time. Early involuntary termination of this program and mandates to provide economic benefits to developers raise fundamental policy questions beyond the scope of a workgroup collaborative. Legislation developed as a result of the 21st Century Energy Plan may affect the net metering program and the interconnection procedures and rules.

B. Proposed Interconnection Procedures for Inverter-Based Generators of 10kW or Less (IREC Model as modified)

1. Organization and Table of Contents: See general comment No. 2 above regarding the draft. Further, the document uses a number of capitalized terms (e.g. Project Developer, Point of Common Coupling, Customer, Spot and Area Network) that are not specifically defined in the definitions section.

There should be a discussion by the workgroup regarding the role of the "Customer" versus that of the "Developer" (or installer). In many cases the installer rather than the customer will control the interconnection process and have the expertise regarding equipment. This should be recognized in the procedures and agreements.

The table and list of attachments should be revised to reflect changes in the contents as the procedures are modified. It appears that section (e) regarding special screening criteria for interconnection to distribution networks may not be needed as a separate section. If all interconnections covered by these procedures are to distribution systems, as expected, the requirements for different distribution networks can be addressed as separate items in the listed criteria, particularly if each requirement applies to a defined type of network (e.g. "Spot" or "Area" networks).

2. Scope (section a): No comments at this time.

3. Standard for Certification (b): There are related concepts of "qualification" (for these procedures) and "certification" (of equipment, as a requirement for qualification). Defining these terms might aid in understanding the differences.

4. Certified Equipment (c): This section is written as if it applied to all sizes of projects as a general matter, rather than the "under 10kW" generators.

Provisions like this one in the proposal need to be worded so they cannot be construed to limit the right of utilities to test facilities to be interconnected, and for consideration of the entire interconnection package as a unit, as opposed to accepting that the use of pre-certified equipment as items of the package automatically means that the entire interconnection as a unit is qualified or certified.

Is it intended that this provision deal with "pre" certified equipment?

5. General Technical Screening Criteria (d): Some of the measures included in this section are restatements and possibly modifications of the IEEE provisions. If the IEEE standard is incorporated by reference, there is no need to repeat its provisions and many of the subsections in (d) could be eliminated as redundant. Subsections (d)(2, 3, 4 and 7) could be omitted for this reason. If the provisions are retained and there are wording variations from the IEEE, these need to be identified and discussed in the working group.

Subsections (d)(2,3,4,7 and 8) are listed here but are not identified as "applicable" screens in subsection (f)(2), which is confusing. In fact, the entire concept of screening calls for more explanation and perhaps definitions.

For subsection (d)(1), if fuses are used as automatic sectionalizing devices, installed on a single phase tap, the fused tap would be a line section (perhaps only serving 2 or 3 customers). The section peak load in this instance can't be measured at the substation and if estimated the permissible generation for the section could be a very low amount.

Subsection (d)(10) is a potential source of controversy, insofar as the question whether a proposed generator requires improvements to utility facilities may be difficult to answer.

6. Special Screening Criteria … (e): This section introduces undefined terms such as Area and Spot Networks. Items (e)(2, 3) are not listed as applicable screens in section (f)(2) and should therefore be eliminated here. These provisions may not need to be identified as "special" criteria in a separate section in the document since they would apply generally for the identified situations.

7. Screening Criteria and Process … (f): The acknowledgment of application per (f)(1) should take place in 3 "business" days after receipt by the utility, rather than calendar days measured from "submission" (to avoid a mailbox rule). The 10 day evaluation period (and all identified processing periods for that matter) should also be measured in "business" days. The determination of incomplete application should occur in the 10 business day period, as well as any determination that the project is not eligible (with explanation).

These time frames may be appropriate for a modest pace of projects seeking interconnection as presently experienced. If there is a significant increase or wide fluctuations in the number of requests for interconnection requiring more dedicated personnel, the costs and time requirements would need to be addressed. Permanent staffing at the levels required to address a sudden short-term increase in the number of applications within the timeline would not be an efficient use of utility resources. Projects take months to develop, plan and install and in some cases the time frames for response could be too short as proposed. One utility reported that developers have dropped off applications late on the day before the Christmas holiday, for example. A procedure should be developed that allows a longer time period in some circumstances instead of putting the utility in a noncompliance situation.

Including the list of "applicable screens" here in (f)(2) seems confusing – why wouldn't that be addressed in sections (d) and (e)?

The additional language in (f)(4) about a possible fully executed interconnection agreement is not needed. No time benefit is gained using a pre-executed agreement by one party.

Section (f)(6) with its concept of automatic approval for non-response by a utility should be removed entirely. There is no reasonable basis to provide for "deemed approval" allowing interconnection to proceed without consent or knowledge of all parties. There are other ways to deal with refusals to respond and there is little indication that this has been a problem in the investigation reports. With proper consideration of safety of the public and utility workers, as well as preventing harm to the distribution system, the procedures should not embrace concepts that can be characterized as default approval.

8. General Provisions and Requirements … (g): Section (g)(4) is one sided and too restrictive. It should be entirely eliminated from the draft. Incorporating a concept of "presumed compliance" will be an invitation to energizing projects prematurely without adequate testing and communication. In consideration of any matter that involves public and employee safety and protecting the system, there must not be a measure in the standards that absolutely bars additional testing and possible controls, or gives the entire discretion to developers. The unreasonable and one-sided nature of this provision calls into question the use of the IREC model as a starting point for the working group discussions. Further, this section introduces the liability insurance issue with a restriction on requiring it, a matter which needs to be fully aired in the working group process. Persons who enter into commercial activities and seek the right to use the utility grid, creating additional risks to others, should not be given blanket exemptions from liability insurance requirements.

There is an issue regarding the requirement for an external disconnect switch that allows utility workers to disconnect the generator without pulling the meter and cutting off all service to the location. Developers object to the costs associated with this switch. This is a safety and reliability issue and deserves full discussion as opposed to adopting language that simply bars the requirement and resolves the issue in favor of complaining developers.

Section (g)(5) calls into question what protection equipment is included in a "certified equipment package." It incorporates a standard that restricts use of additional protective equipment if the developer equipment performance is "negatively impacted in any way" which is a very broad and undefined standard.

Section (g)(8) is worded as a limitation on the ability of a utility to require additional testing (after "approval under this rule"). Utilities reserve the right to require and/or observe testing before interconnection to their systems and to inspect the interconnection and these procedures should not restrict that right. To follow the 1547 standard, the customer will have to perform the commissioning tests. The utility should also have the option to see the proposed test plan, witness the testing, and/or review the results of the tests at its discretion.

Section (g)(9) is worded to require both noncompliance with IEEE 1547 and adversity to safety and reliability of the distribution system as the basis for disconnecting a project. The latter situation (safety and reliability) alone should be a basis for disconnection.

9. Attachment 1 – Definitions: As noted above, there are many terms that call for definition. Some were defined in the IREC source document but these were removed.

The definition of "Equipment Package" (or sections where this term is used) should explain the need for both the system and components to be IEEE compliant and also compliant with the interconnection policy.

A definition of U.L should be included.

10. Attachment 2 – Application: The application should identify both the customer and the developer/installer if different.

Identification and contact information for the inverter (salesperson, supplier) should be included.

The inverter serial number may not be available at the application stage. There may be a need to have identification of multiple inverters for some projects (larger systems or 3 phase output).

A one-line diagram and site drawing should be included with the application.

The "meter removal non-liability" wording should be changed to recognize that it is the utility, not the developer, who may elect not to require an accessible manual disconnect device.

The applicable certification standard should be included in the table for components.

11. Attachment 3 – Interconnection Agreement: This is a complex document that requires full consideration in the working group, since this draft was prepared by nonparticipants (IREC).

The 2 hour limit on operational testing in Section 1.0 should be removed.

The phrase "at its own expense" in Section 2.3.1 should be removed.

The deemed waiver of the witness test in Section 2.3.2 should be removed and this section and 2.3.3 should require any waivers to be in writing to eliminate future contention.

In section 2.4 the written explanation of improper installation should be due in 5 business days after disconnection instead of at the time of disconnection. Problems may warrant immediate disconnection and time should be allowed for the report.

The indemnification language in Section 6.0 was not acceptable and there have been several suggestions of alternative approaches attached hereto. This issue requires full discussion.

Why is the draft proposing to have no insurance requirement for developers (Section 7.0)? New risks are associated with these projects and indemnity provisions alone provide little protection if many of the developers are just homeowners. Some states require $300,000 as was recognized in the IREC model rules.

In general, the provisions on indemnity, insurance and limitation of liability require more discussion and the use of the proposed draft should not create any presumptions that its provisions are reasonable. One utility suggests adding a provision to escalate the level of coverage over time to keep up with inflation. See language added at the end of Attachment A.

The provision in Section 10.0 should provide for termination if the new owner does not accept the agreement in writing.

Consideration should be given to having the installer and the customer sign the agreement, since the installer will be responsible for the interconnection at least up to the time the project starts operating.

12. Attachment 4 – Certificate of Completion: The only comment so far is to add a heading for the "Witness Test" waiver.

C. Proposed Interconnection Rule Revision

The only proposal is to add the "under 10kW facility" item in Rules 3 and 6. The primary comment so far is to define "qualified inverter-based projects" or refer to the definition.

In Rule 6, the change leads to a longer period (20 days) for the smallest projects, with a shorter period (2 weeks) for other projects under 30 kW. The procedures under Rule 3 would cover the "under 30 kW" group, for most situations.

As indicated in the earlier interconnection investigation, utilities believe the time deadlines in general need revision and this issue would be addressed in the rulemaking proceedings as well, along with other possible rule changes applicable generally and not just to small projects.

D. Simplified Net Metering Program Proposal

The numbers below correspond to the numbered paragraphs in the Staff proposal. See also general comment No. 5 in Part A.

1. Pre-certified Inverters: Use of the standards is acceptable; however, utilities reserve the right to require testing and inspection of all projects, which should not be limited.

2. Inverter Listing: Individual utilities should not be assigned the task of identifying and listing inverter models. A statewide effort through MEGA, Staff, utilities and developers could be developed. Otherwise, the manufacturers should contact the utilities to pre-certify equipment. Important requirements include passing the anti-islanding test and providing test results.

3. Additional Equipment: This issue should be handled on a project specific basis through the interconnection agreements. The identification of acceptable equipment could be included in a statewide coordinated effort as for the inverter listing above.

4. Net Metering Charges: The current net metering policy established by consensus contains provisions for alternate methods of metering and describes the method of charging and crediting customers for various meter configurations. One of the permitted methods allowed use of a single meter measuring flow in both directions, with the customer to pay for transmission and distribution costs through a separate rate charge. This concept is similar to the proposal and the separate charge could be the delivery component of the customer's base rate charged against the site use. Site use could either be estimated or established through metering of power in and generation at the site. Thus, the existing consensus does provide the framework for the simplified approach for small projects although the option to elect the full metering configurations should be left to the customer. There is benefit to the customer in knowing the site generation amount, for example. The current 3-meter option used by Detroit Edison provides data the customer can use for selling RECs.

As described in reports filed previously, various utilities have developed different metering configurations under the net-metering consensus agreement scheduled to run through at least 2009. Why not continue to allow alternate measures that comply with the consensus agreement, to provide data to determine customer preferences and workability of the different approaches?

Any agreement regarding a new net metering consensus such as the one proposed should contain a provision recognizing that the minimum monthly fixed charge is not a matter of absolute discretion but should be set at a level adequate to recover the customer's share of all appropriate costs. In other words, once an arrangement is established, the proponents of net metering should not be able to argue that the Commission should set the minimum bill at zero as an incentive measure to promote net metering with costs borne by other utility customers.

5. Reverse Meter Rule Change: Use of a single meter set to run backwards can create significant billing problems. If the end reading is less than the start reading, some billing systems would recognize this as meter rollover causing incorrect bills for the net metering customer. Customers with a concern about costs associated with metering could be allowed the option to have flow measured in and out, without separate metering of the generation under the existing consensus agreement.

6. Net Metering Single-Meter Approach: The comments above apply to this section.

7. Additional Metering Data – Utility Request: This issue needs further discussion. If power quality issues and the need for troubleshooting arise, it is unclear that policy should favor assigning all metering costs to the utility. This matter may be more appropriate for case-by-case evaluation.

8. Net Excess Generation Carrying: The existing consensus agreement provided for reducing the NEG balance to zero at year-end to: (1) provide a disincentive to over-sizing units, and (2) provide a potential source of funds to offset program costs. Eliminating the annual reset may remove all consequences to disregarding the provision requiring that units be sized based on the customer's annual energy needs. Net metering customers benefit from the use of excess funds for program costs. An alternative approach to consider may be to allow customers to time the billing month for the NEG balance reset, since their balance should approach zero at some point during the year if the unit is properly sized.

Utilities have not yet developed a consensus position on this issue, which requires further discussion in the workgroup.

Comments compiled for:

MICHIGAN ELECTRIC AND GAS ASSOCIATION

April 16, 2007

MICHIGAN ELECTRIC COOPERATIVE ASSOCIATION

CONSUMERS ENERGY COMPANY

THE DETROIT EDISON COMPANY

Attachment A – Ideas for Liability/Indemnity Language

Detroit Edison provided the following provisions in order of preference:

17. INDEMNIFICATION

A. Customer covenants and agrees that it shall defend, indemnify and hold Company, and all of its officers, agents and employees harmless for any claim, loss, damage, cost, charge, expense, lien, settlement or judgment, including interest thereon, whether to any person, including employees of Customer, its Subcontractors and Suppliers, or property or both, arising directly or indirectly out of or in connection with Customer's or any of its Subcontractor's or Supplier's performance of the Agreement or in connection with the performance of the Agreement, to which Company or any of its officers, agents or employees may be subject or put by reason of any act, action, neglect or omission on the part of Customer, any of its Subcontractors or Suppliers or Company, or any of their respective officers, agents and employees. Without limiting the foregoing, said obligation includes claims involving Customer's, Supplier's or Subcontractor's employees injured while going to and from the premises. If the Agreement is one subject to the provisions MCL 691.991, then Customer shall not be liable under this section for damage to persons or property directly caused or resulting from the sole negligence of Company, or any of its officers, agents or employees.

B. In the event any suit or other proceedings for any claim, loss, damage, cost, charge or expense covered by Customer's foregoing indemnity should be brought against Company or any of its officers, agents or employees, Customer hereby covenants and agrees to assume the defense thereof and defend the same at Customer's own expense and to pay any and all costs, charges, attorney's fees, and other expenses, and any and all judgments that may be incurred by or obtained against Company or any of its officers, agents, or employees in such suits or other proceedings. In the event of any judgment or other lien being placed upon the property of Company in such suits or other proceedings, Customer shall at once cause the same to be dissolved and discharged by giving bond or otherwise.

The following is the full Indemnity provision taken from the IREC Model Rules, with some minor clarifying modifications that don't change the meaning of the Model Rules, as proposed).

12. Liability Provisions

12.1 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, exemplary or punitive damages of any kind whatsoever. This provision does not limit the obligations identified in Paragraph 12.2.

12.2 Indemnification

a. The Company shall assume all liability for and shall indemnify the Customer for any claims, losses, costs, and expenses of any kind or character to the extent that they result from the Company's negligence in connection with the design, construction, or operation of its facilities as described on Exhibit A; provided, however, that the Company shall have no obligation to indemnify the Customer for claims brought by claimants who cannot recover directly from the Company. Such indemnity shall include, but is not limited to, financial responsibility for:

(a) the Customer's monetary losses; (b) reasonable costs and expenses of defending an action or claim made by a third person; c) damages related to the death or injury of a third person; (d) damages to the property of the Customer; (e) damages to the property of a third person; (f) damages for the disruption of the business of a third person.

In no event shall the Company be liable for consequential, special, incidental or punitive damages, including, without limitation, loss of profits, loss of revenue, or loss of production. The Company does not assume liability for any costs for damages arising from the disruption of the business of the Customer or for the Customer's costs and expenses of prosecuting or defending an action or claim against the Company. This paragraph does not create a liability on the part of the Company to the Customer or a third person, but requires indemnification where such liability exists. The limitations of liability provided in this paragraph do not apply in cases of gross negligence or intentional wrongdoing.

b. The Customer shall assume all liability for and shall indemnify the Company for any claims, losses, costs, and expenses of any kind or character to the extent that they result from the Customer's negligence in connection with the design, construction, or operation of its facilities as described on Exhibit A; provided, however, that the Customer shall have no obligation to indemnify the Company for claims brought by claimants who cannot recover directly from the Customer. Such indemnity shall include, but is not limited to, financial responsibility for:

(a) the Company's monetary losses; (b) reasonable costs and expenses of defending an action or claim made by a third person; (c) damages related to the death or injury of a third person; (d) damages to the property of the Company; (e) damages to the property of a third person; (f) damages for the disruption of the business of a third person. In no event shall the Customer be liable for consequential, special, incidental or punitive damages, including, without limitation, loss of profits, loss of revenue, or loss of production.

IREC MR-I2005: IREC Model Interconnection Standards
Limitation of Liability

The Customer does not assume liability for any costs for damages arising from the disruption of the business of the Company or for the Company's costs and expenses of prosecuting or defending an action or claim against the Customer. This paragraph does not create a liability on the part of the Customer to the Company or a third person, but requires indemnification where such liability exists. The limitations of liability provided in this paragraph do not apply in cases of gross negligence or intentional wrongdoing.

Consumers Energy presented the following based on the IREC language and its current interconnection operating agreement, to be project specific:

Each Party shall at all times assume all liability for, and shall indemnify and save the other Party harmless from, any and all damages, losses, claims, demands, suits, recoveries, costs, legal fees, and expenses for injury to or death of any person or persons whomsoever occurring on its own system, or for any loss, destruction of or damage to any property of third persons, firms, corporations or other entities occurring on its own system, including environmental harm or damage arising out of or resulting from, either directly or indirectly, its own Interconnection Facilities, or arising out of or resulting from, either directly or indirectly, any electric energy furnished to it hereunder after such energy has been delivered to it by such other Party, unless caused by the sole negligence or intentional wrongdoing of the other Party.

The provisions of this Section 6 shall survive termination or expiration of this Agreement.

Consumers Energy insurance provision language:

Insurance: Project Developer shall obtain and continuously maintain throughout the term of this Agreement liability insurance covering bodily injury and property damage liability with a per occurrence and annual policy aggregate amount of at least:

Project Capacity	**Minimum Limit**
Less than 30 kW	$500,000

When requested in writing by Consumers, said limit shall be increased each year that this Agreement is in force to a limit no greater than the amount arrived at by increasing the original limit by the same percentage change as the Consumer Price Index - All Urban Workers (CPI-U.S. Cities Average). Such policy shall include, but not be limited to, contractual liability for indemnification assumed by Project Developer under this Agreement.

Evidence of insurance coverage on a certificate of insurance shall be provided to Consumers upon execution of this Agreement and thereafter within ten (10) days after expiration of coverage; however, if evidence of insurance is not received by the 11th day, Consumers has the right, but not the duty, to purchase the insurance coverage required under this Section and to charge the annual premium to Project Developer. Consumers shall receive thirty (30) days advance written notice if the policy is cancelled or substantial changes are made that affect the additional insured. At Consumers' request, Project Developer shall provide a copy of the policy to Consumers.

JOHN SARVER
<u>MICHIGAN ENERGY OFFICE</u>

COMMENTS ON UNDER 10 KW
NET METERING & INTERCONNECTION PROCEDURES
U-15113
BY JOHN SARVER
MICHIGAN ENERGY OFFICE
April 16, 2007

The Commission's February 27, 2007 Order, in Case No. U-15113, directed the Engineering Section of the Commission's Operations and Wholesale Markets Division to establish a workgroup to develop faster and less complex interconnection procedures for 10 kW and under interconnection projects. The Commission additionally directed the Michigan Renewable Energy Program (MREP) Ratemaking and Net Metering Committee to form a task force to seek a new consensus and report to the Commission within 90 days on a simplified approach for net metering for inverter based systems smaller than 10 kW.

These comments pertain to draft staff documents prepared in response to the Commission order. Small photovoltaic and wind energy systems can provide clean, renewable power while reducing demands on the electric distribution system and, in the case of photovoltaic systems, providing power at peak times when power is most needed. Michigan citizens, businesses, and public institutions are making investments in small electric renewable energy systems in order to reduce electric costs but also to capture the societal benefits that come from clean, renewable energy. State policies should encourage these investments whenever possible.

Draft staff documents provide a more simplified approach for net metering and interconnection for inverter based systems smaller than 10 kW. Staff has addressed the key issues that can make net metering a viable program in Michigan.

- All inverters certified under UL 1741 shall be considered pre-certified, with no additional testing or certifications required.
- A rule change to R480.3605 to allow meters to reverse register (that is, to spin backward).
- Customer credit per kWh for net excess generation shall be based on the retail price paid by the customer, including all energy and power supply cost recovery charges.
- If a participating utility seeks additional metering data, the utility could be allowed to install and operate additional meters, but all costs associated with the additional meters would not be the responsibility of the net metering customer.
- At the end of a net metering year, the utility will carry the customer’s net excess generation forward to the next year or issue a check to the customer with the net excess generation valued at the utility’s average annual avoided cost rate for the year.

The Energy Office supports these proposed revisions and believes they can make net metering a viable program in Michigan. Thank you for the opportunity to make comments.

Garth Ward
Michigan Wind Power

Hi,, I think the Drafts look great,, In the "Interconnection Requirements" draft,, I am going to assume with more of these smaller household units that the "Project Developer" will in some cases be the homeowner...Right???

Garth Ward, Michigan Wind Power - Power to the people

See us at, www.michiganwindpower.net

Tom Kervin

Julie Baldwin,

First, thank you for your efforts on this important project. I am a home owner who would like to be environmentally friendly. Someday, if conditions are right, I would like to put a small solar (photovoltaic) system up at my residence for electricity creation. With that in mind, I would like to see any policies put into place that would assist a home owner on a small project of this nature. I would also like to see "solar" as an official part of the documentation. Any advice for me at this time?

Thanks Again,

Tom Kervin
tkkervin@hotmail.com

Pierre Marcotte

Julie Baldwin

Line item #4 states that net metering customers will pay a minimum amount each month to cover an appropriate portion of customer- based fixed charges.

Are customers paying this charge right know

What is this based fixed charge?

As it is right know the customer electricity that he or she produces is consumed on site and excess is credited to the customers at the end of the month.

If the system is not producing more than it peak power output or more than one megawatts

Why is the customer paying additional fees?

Line item #6 as it is the customer has to purchase this meter, what is wrong with the meter that he already has on his house, it is an electromechanical energy-only meter.

Explain why I need to purchase a new meter.

What dose the last line in paragraph 6 mean (including all energy power supply cost recovery charges?)

Please respond

Pierre Marcotte

Sr. Field Operation Tech.

cell: 269-804-9565

Kalamazoo MI.

PIERRE.J.MARCOTTE@SPRINT.COM

S.U.R. ENERGY SYSTEMS, LC
Suburban Urban Rural
.
Design, Sales, and Installation of Renewable Energy Systems

In the matter, on the Commission's own)
Motion, to commence an investigation)
Into the interconnection of independent Case No. U-15113
Power producers with a utility's system)

COMMENTS OF S.U.R. ENERGY SYSTEMS, LC- UNDER 10K INTECONNECTION PROCEDURE

We would like to thank the commission for the recent attention given to the matter of the ease of interconnection for small residential scale systems, and the improvements that the IREC model brings to the current interconnection procedure. The 4 hours or so required to fill out the current document, even for those with the expertise to do so, seems more than a little excessive for a simple inverter based system with standard listings, especially when the size is unlikely to exceed the energy use in the home or business. The two page IREC form is much more reasonable.

I was not sure of the exact meaning of the table in section (d) General Technical Screening Criteria, under paragraph 4. The second block in the table reads "if a three-phase (effectively grounded) or single-phase generator, interconnection must be line to neutral". I wonder why this appears. Listed inverters can be bought with AC outputs of 120V, 208V, 277V, and larger units at 480V (three phase output, primarily with larger inverters). The meaning of this table is unclear to me. We have interconnected many units at 208V that do not have a neutral wire. An inverter of this sort would be connected to two of the three phases of a 120/208V panel. We try to use 3 inverters whenever possible to keep the output balanced but have successfully used only 2 in the past, on at least one occasion. I understand that the new generations of inverters may all have neutral wires, even for 208V, but I would hope this table does not mean that a 120V inverter, or a transformer between the inverter and the panel, would be required in a building that was 120/208VAC. A single 208V inverter should be able to go in a building that is 208V between two of the phases. I know of no reason why it should not be allowed. To change this would restrict the design of the systems where a 208V inverter is optimal, unnecessarily adding expense.

Also, the only nice thing about the old form was that it was uniform from one utility to the next. Please continue this policy with the new, simpler format. We appreciate this.

221 BUENA VISTA AVE • ANN ARBOR, MI • 48103
PHONE: (734)-913-9944 • FAX: (734)-913-9915

I applaud the inclusion of section (g) number 4 that precludes the utilities for charging for additional equipment. It is my understanding that this requirement is being removed in the areas of the country where utilities have been allowed to add this equipment. My main concern is that meters have not been EXPLICITLY included in paragraph (g)5. Instead, they are mentioned in line 6, which says meters will be covered in the tariffs. The meters, and the ridiculous notion of having three, or even two, should be expressly eliminated at this time with this current action. Waiting for changes to the tariffs to take place, and to ensure that the elimination of multiple meters will be included explicitly in each tariff at whatever time in the future seems too risky. This is the time to make that hindrance go away.

Thank you again for your attention to these matters.

Sincerely,

John Wakeman

Owner, SUR Energy Systems, LC

From: "EricLipson@yahoo.com" <ericlipson@yahoo.com>
Date: April 15, 2007 9:36:35 PM GMT-04:00
To: baldwinj2@michigan.gov, millsb2@michigan.gov
Subject: Proposed net metering rules

Congratulations and thanks to the PSC for the proposed revisions which are head and shoulders above the current non-functional, counter-productive process of 19 page forms, three meter systems, unwarranted fees and general obstructionism which the big energy companies have been trying to use as dis-incentives to alternative energy. The proposed rules go a long way to making net metering a workable system. Thanks for listening to those of us who spoke and wrote to the PSC on this issue. Excellent ideas: One Meter that goes backwards and forwards. Read once a year. No cost or reasonable costs to apply and hook up. UL certified equipment as a substitute for the current ridiculous and unnecessary individual certification. Simplified applications. And requiring the utility to buy back the excess. All long overdue.
Still needed: propety tax abatement for renewable energy systems, rebates per kw hour for wind solar and geo-thermal systems and other incentives for installing renewable energy systems. Together this will help create jobs in this sector as well as making the grid more robust by encouraging distributed energy rather than central generating stations, reduce our dependence on fossil fuels and imported fuels, and reduce greenhouse emissions. Thanks to the PSC for representing the best interests of the whole state and not just rolling over for the big energy producers.
Eric Lipson

NEMCOG
Northeast Michigan Council of Governments

121 E. Mitchell St. * P.O. Box 457
Gaylord, MI 49734
Voice: 989.732.3551
Fax: 989.732.5578
Web: www.nemcog.org

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June 18, 2007

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MICHIGAN PUBLIC SERVICE COMMISSION

JUN 22 2007

OPERATIONS & WHOLESALE MARKETS DIVISION

Ms. Julie Baldwin, Staff Engineer
Michigan Public Service Commission
PO Box 30221
Lansing, MI 48909

Dear Ms. Baldwin:

On behalf of the Northeast Michigan Council of Government's (NEMCOG), Board of Directors I would like to express the Board's support for the Public Service Commission's Staff Draft Proposal for Simplified Net Metering Program for Inverter-Based Systems 10KW or less.

Renewable energy projects are gaining support and momentum in northeast Michigan. As an example, a community project in Hillman, MI involved the redevelopment of a Grist Mill on the Thunder Bay River. In recreating the hydroelectric portion of the project, the community also chose to add solar, and geothermal as alternative energy sources. The Grist Mill will generate under the 10KW threshold, however under the current rules the Mill will lose any excess energy credit at the end of the year and when selling power to the grid, and will not receive retail price.

The Net Metering proposal was brought to the attention of the Board at its meeting on May 17, 2007. The Board, after reviewing the Draft Staff proposal unanimously supported the draft proposal. In particular, the Board is supportive of customers who provide power to the grid to receive retail price, and in addition allowing utilities to either carryover the customer's net excess generation forward to the next year or issue a check to the customer with the net excess generation valued at the utility's average annual avoided cost rate for the year. .

We appreciate the efforts of the staff of the Public Service Commission in addressing the concerns of small renewable energy generators providing power to the grid.

Regional Cooperation Since 1968

Sincerely,

Diane Rekowski

Diane Rekowski
Executive Director

Alcona * Alpena * Cheboygan * Crawford * Emmet * Montmorency * Oscoda * Otsego * Presque Isle

April 20, 2007 Comments

30 kW and Larger Interconnection Procedures Workgroup

Michigan Public Service Commission

This document contains comments on the following objectives:

1. Identify reasonable and achievable interconnection time deadlines.
2. Propose a system for determining whether interconnection costs are reasonable, actual costs.
3. Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections).
4. Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.
5. Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system.

Comment Summary

William Stockhausen

Thank you for the opportunity to comment.

In order to meet the upcoming RPS requirements the interconnection process for the 30 - 750 kW segment will have to be more streamlined and cost effective.

The following parameters need to be relaxed to stimulate interest and effect viability for small renewable power producers to come on line:

1) Extensive studies for engineering and systemic line effects that are costly and time consuming (doubly true with rotary machinery vs inverter type) are unnecessary. These kinds of studies aren't done in this power segment when the customer is a user rather than a generator.

2) Additional liability insurance can be dispensed with. There are no instances of linemen being injured due to a small power producer keeping the line energized. Protective relaying and lineman training make this a needless expense.

3) Some current stand by rates are exorbitant and also have a chilling effect for a co-gen or small power producer. Stand by rates need to be eliminated entirely - they fly in the face of the whole RPS effort.

4) Utility grade relays are expensive and in excess of the protection needed in this power segment. Industrial grade are sufficient.

Regards,

William Stockhausen
218 W. Dunlap St.
Northville, MI 48167
248-349-2833

Greg Sirna

I stated my thoughts to the MPSC last December. But I still think they apply to today's discussion. I will be going through an interconnection with Consumers Energy soon and I will than have a better understanding for the procedures involved. My biggest concern is the metering. Last time I interconnected with Consumers Energy I was charged $4,000 for the metering (on the secondary side of the line, 480 volts). When my project failed and the contract was canceled, the meters were removed (and more than likely used somewhere else as there was nothing wrong with them), yet no money was returned to me. So what did I pay for? This is a typical utility tactic. Utility grade controls vs industrial grade controls for projects under 750 kws is an other mater that needs attention. There should be standardized components available. As I said before the MPSC needs to walk through an interconnection of there own to experience first hand the Utility tactics to keep us off the grid.

Dec. 19, 2006
My thoughts on interconnection with the utilities are as follows: The cost associated with just the application of the interconnection with the utilities adds a burden for the small systems. The controls for the generators between the customers and the utilities need to be simple industrial grade not utility grade. The metering for the system should not be complicated nor expensive. The utility should not be able to charge $4000 for a set of meters that they retain ownership of. The interconnection package should not be designed to cause the project to fail as the utility does not want these project to make power as it is not in their financial self interest to let others make and sell power. The one line drawings for interconnection should be relegated to the project and simple with not everything including the kitchen sink in it. There are a host of issues that will arise when doing a project, the commission should implement their own small project to see first hand the stalling overburdening tactics of the utilities. Thank You Greg Sirna Centreville Hydro

MICHIGAN REGULATED ELECTRIC INDUSTRY COMMENTS ON OBJECTIVES OF 30 kW AND LARGER INTERCONNECTION PROCEDURES WORKGROUP

These informal comments are submitted by the Michigan Electric and Gas Association on behalf of Michigan regulated electric utilities including MEGA members, the electric distribution Cooperatives, The Detroit Edison Company and Consumers Energy Company. The MPSC Staff (Staff) published a set of proposed objectives for a working group and requested initial proposals by interested parties on how to achieve the objectives. This working group relates to the interconnection procedures for projects sized at 30 kW and larger. The initial comments were requested by Friday, April 20, 2007.

The following specific objectives were proposed:

1. Identify reasonable and achievable interconnection time deadlines.
2. Propose a system for determining whether interconnection costs are reasonable, actual costs.
3. Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections).
4. Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.
5. Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system.

The following initial comments on each of these objectives are provided on behalf of the industry group. The workgroup process will provide the opportunity for more detailed discussion among interested parties and more detailed proposals.

Objective 1: Identify reasonable and achievable interconnection time deadlines.

The investigation and comments in MPSC Case No. U-15113 indicated a need to reconsider the time deadlines in the Michigan interconnection rules. This will require discussion among all participants in the working group. The deadlines should account for the impact of long lead times for ordering equipment and making system modifications, if needed to complete an interconnection. Although the smallest projects (under 10 kW) can usually be addressed in a more expedited time frame, the time deadlines for other projects 30 kW and larger are typically subject to site specific work requirements and other matters (right-of-way, equipment availability, labor, operating agreement, testing) that may not directly correlate with the project size categories used in the rules. Utilities may be able to stock some items of equipment with long lead times. Depending on the circumstances, time requirements could extend out to six months or more.

The conduct of a pre-application meeting between the utility and interconnection applicant should facilitate more rapid interconnections and exchange of necessary information.

No overall deadline "clock" provision should start until a completed application is submitted and sufficient time should be allowed for the initial review of the application for completeness. For example, notification of receipt of the application in three business days would be the first step and then notification of an incomplete application with identification of the missing information would be required in ten business days. Only after all the missing information is provided would the "clock start" on the completion deadlines.

Other items which would facilitate timely completion of interconnections would include development of the approved equipment lists (relays), conceptual cost estimates based on generic interconnection parameters (subject to change based on actual circumstances for a specific project), and possibly a down payment for the engineering study and ordering materials made prior to execution of the interconnection agreement. A letter of intent could be considered for this last item.

One useful framework for discussion would be the "Wisconsin PSC 119" rules for interconnecting distributed generation facilities, submitted with these comments for informational purposes.

<u>Objective 2:</u> **Propose a system for determining interconnection costs are reasonable (actual costs)**

Further discussion and possible clarification of Objective 2 may be necessary. Utilities already charge customers the actual cost of modifications for an interconnection project. The process involves billing based on scope of project for materials and labor in a manner similar to customer line extensions. The use of utility overheads in this practice is consistent with approved MPSC accounting practices. Utilities are willing to provide actual detailed cost breakdowns based on major components of the project such as the easement, materials and labor. Customers are not permitted to perform work on utility assets.

<u>Objective 3:</u> **Study impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections)**

Many or even most generator projects connecting at the distribution level would not impact the transmission system or adjacent distribution system. If, however, the interconnection project is large enough to affect these other systems, the providers should be consulted. The smaller projects (likely those under 2 MW) are less likely to impact other systems (although they could) and utilities suggest considering projects under 2 MW as a cutoff point for <u>requiring</u> the independent power producer to consult with the affected transmission or distribution system. Further, each project is evaluated to determine the impact of capacity needs, flow back potential, effects on connected distribution systems, and upstream coordination in relation to the transmission system.

Utilities will notify the transmission provider of potential impacts to the transmission system; however, the independent power producer should apply with the transmission provider as well as the utility, where appropriate (i.e. 2 MW or more). The MISO tariff governs the payment of cost of transmission system improvements by the project developer to the transmission provider.

Objective 4: **Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.**

Unity (1.0) power factor on the high side of the step up transformer should be the base requirement for all interconnected generator projects. This is consistent with recommendations contained in the document "Final Report on the August 14, 2003 Blackout in the U.S. and Canada: Causes and Recommendations" (April, 2004) prepared by the U.S. – Canada Power System Outage Task Force.

The standards could provide for mutual agreement on deviation from the base requirement. If a project deviates from the unity base, the consequences can be additional VAR regulation (capacitors, inductors) required for the system at the developer's cost. A low or high power factor appears as load on the system and could affect the function of existing regulators, capacitor banks, etc.

Objective 5: **Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system**

This objective will require more discussion and clarification. The suitability of location might best be left to discussions at the pre-application meetings for a specific project.

General public identification of such areas may create concerns regarding security and terrorism. It is unwise to make too much knowledge of the utility system function available in a public manner.

The large size and dynamic nature of utility distribution systems makes this a difficult task. Changes to the system from storm damage, capacity planning and other modifications could alter the "areas of opportunity" over time.

Utilities have a valid concern with possible liability claims based on performance of a project after selection of the optimal location. However, there could be feedback in the discussions regarding the best choice among several locations presented by the developer for a project.

Comments compiled for:

April 20, 2007

MICHIGAN ELECTRIC AND GAS ASSOCIATION
MICHIGAN ELECTRIC COOPERATIVE ASSOCIATION
CONSUMERS ENERGY COMPANY
THE DETROIT EDISON COMPANY

Chapter PSC 119

RULES FOR INTERCONNECTING DISTRIBUTED GENERATION FACILITIES

Subchapter I — General

PSC 119.01 Scope. This chapter implements s. 196.496, Stats. It applies to all DG facilities with a capacity of 15 MW or less that are interconnected, or whose owner seeks to have interconnected, to an electric public utility's distribution system. It also applies to all electric public utilities to whose distribution systems a DG facility is interconnected, or to which interconnection is sought. These rules establish uniform statewide standards for the interconnection of DG facilities to an electric distribution system.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.02 Definitions. In this chapter:

(1) "ANSI" means American National Standards Institute.

(2) "Applicant" means the legally responsible person applying to a public utility to interconnect a DG facility to the public utility's distribution system.

(3) "Application review" means a 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.

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

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

(6) "Category 3" means a DG facility of greater than 200 kW and not more than 1 MW.

(7) "Category 4" means a DG facility of greater than 1 MW and not more than 15 MW.

(8) "Certified equipment" means a generating, control or protective system that has been certified by a nationally recognized testing laboratory as meeting acceptable safety and reliability standards.

(9) "Commission" means the public service commission of Wisconsin.

(10) "Commissioning test" means the process of documenting and verifying the performance of a DG facility so that it operates in conformity with the design specifications.

(11) "Customer" means any person who is receiving electric service from a public utility's distribution system.

(12) "DG" means distributed generation.

(13) "DG facility" has the meaning given in s. 196.496 (1), Stats.

(14) "Distribution feeder" means an electric line from a public utility substation or other supply point to customers that is operated at 50 kV or less, or as determined by the commission.

(15) "Distribution system" means all electrical wires, equipment, and other facilities owned or provided by a public utility that are normally operated at 50 kV or less.

(16) "Distribution system study" means a study to determine if a distribution system upgrade is needed to accommodate the proposed DG facility and to determine the cost of any such upgrade.

(17) "Engineering review" means a study that may be undertaken by a public utility, in response to its receipt of a completed standard application form for interconnection, to determine the suitability of the installation.

(18) "Fault" means an equipment failure, conductor failure, short circuit, or other condition resulting from abnormally high amounts of current from the power source.

(19) "IEEE" means Institute of Electrical and Electronics Engineers.

(20) "Interconnection" means the physical connection of a DG facility to the distribution system so that parallel operation can occur.

(21) "Interconnection disconnect switch" means a mechanical device used to disconnect a DG facility from a distribution system.

(22) "Inverter" means a machine, device, or system that converts direct current power to alternating current power.

(23) "Islanding" means a condition on the distribution system in which a DG facility delivers power to customers using a portion of the distribution system that is electrically isolated from the remainder of the distribution system.

(24) "kV" means kilovolt.

(25) "kW" means kilowatt.

(26) "Material modification" means any modification that changes the maximum electrical output of a DG facility or changes the interconnection equipment, including:

(a) Changing from certified to non−certified devices.

(b) Replacing a component with a component of different functionality or UL listing.

(27) "MW" means megawatt.

(28) "Nationally recognized testing laboratory" means any testing laboratory recognized by the U.S. Department of Labor Occupational Safety and Health Administration's accreditation program.

Note: A list of nationally recognized testing laboratories is available at www.osha.gov/dts/otpca/nrtl/index.html.

(29) "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.

(30) "Parallel operation" means the operation, for longer than 100 milliseconds, of an on−site DG facility while the facility is connected to the energized distribution system.

(31) "Paralleling equipment" means the generating and protective equipment system that interfaces and synchronizes a DG facility with the distribution system.

(32) "Point of common coupling" means the point where the electrical conductors of the distribution system are connected to the customer's conductors and where any transfer of electric power between the customer and the distribution system takes place.

(33) "Public utility" has the meaning given in s. 196.01 (5), Stats.

(34) "Standard application form" means PSC Form 6027 for Category 1 DG facilities or PSC Form 6028 for Category 2 to 4 DG facilities.

(35) "Standard interconnection agreement" means PSC Form 6029 for Category 1 facilities or PSC Form 6030 for Category 2 to 4 DG facilities.

Note: A copy of PSC Forms 6027 to 6030 can be obtained at no charge from your local electric utility or from the Public Service Commission, PO Box 7854, Madison, WI 53707−7854.

(36) "Telemetry" means transmission of DG operating data using telecommunications techniques.

(37) "UL" means Underwriters Laboratory.

(38) "Working day" has the meaning given in s. 227.01 (14), Stats.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

Subchapter II — General Requirements

PSC 119.03 Designated point of contact. Each public utility shall designate one point of contact for all customer inquiries related to DG facilities and from which interested parties can obtain installation guidelines and the appropriate standard commission application and interconnection agreement forms. Each public utility shall have current information concerning its DG point of contact on file with the commission.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

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 5 working days, its guidelines and the appropriate standard application form.

(2) The applicant shall complete and submit the standard application form to its public utility.

(3) Within 10 working days of receiving a new or revised application, the public utility shall notify the applicant whether the application is complete.

(4) Within 10 working days of determining that the application is complete, the public utility shall complete its application review. 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, 10 working days.

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

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

(d) Category 4 DG application, 40 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, 60 working days unless a different time period is mutually agreed upon.

(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 10 working days, for a Category 1 or 2 DG project, or 20 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.

(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 5 working days, for a Category 1 DG project, or within 10 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.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

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. 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		
Category	**Generation Capacity**	**Minimum Liability Insurance Coverage**
1	20 kW or less	$300,000
2	Greater than 20 kW to 200 kW	$1,000,000
3	Greater than 200 kW to 1 MW	$2,000,000
4	Greater than 1 MW to 15 MW	Negotiated

(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.

History: **CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.**

PSC 119.06 Modifications to the DG facility. The applicant shall notify the public utility of plans for any material modification to the DG facility by providing at least 20 working days of advance notice for a Category 1 DG facility, 40 working days for Category 2 DG facility, and 60 working days for a Category 3 or 4 DG facility. The applicant shall provide this notification by submitting a revised standard application form and such supporting materials as may be reasonably requested by the public utility. The applicant may not commence any material modification to the DG facility until the public utility has approved the revised application, including any necessary engineering review or distribution system study. The public utility shall indicate its written approval or rejection of a revised application within the number of working days shown in the table below. Upon completion of the application process, a new standard interconnection agreement shall be signed by both parties prior to parallel operation. If the public utility fails to respond in the time specified in Table 119.06−1, the completed application is deemed approved.

Table 119.06−1		
Category	Generation Capacity after Modification	Working Days for Utility's Response to Proposed Modifications
1	20 kW or less	20
2	Greater than 20 kW to 200 kW	40
3	Greater than 200 kW to 1 MW	60
4	Greater than 1 MW to 15 MW	60

History: **CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.**

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.**

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.

Table 119.08−1				
Category	**Generation Capacity**	**Application Review Fee**	**Engineering Review Fee**	**Distribution System Study Fee**
1	20 kW or less	None	None	None
2	Greater than 20 kW to 200 kW	$250	Max. $500	Max. $500
3	Greater than 200 kW to 1 MW	$500	Cost based	Cost based
4	Greater than 1 MW to 15 MW	$1000	Cost based	Cost based

(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.

History: **CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.**

PSC 119.09 Disconnection. A public utility may refuse to connect or may disconnect a DG facility from the distribution system only under any of the following conditions:

(1) Lack of approved standard application form or standard interconnection agreement.

(2) Termination of interconnection by mutual agreement.

(3) Non−compliance with the technical or contractual requirements.

(4) Distribution system emergency.

(5) Routine maintenance, repairs, and modifications, but only for a reasonable length of time necessary to perform the required work and upon reasonable notice.

History: **CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.**

PSC 119.10 One−line schematic diagram.

(1) The applicant shall include a 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.

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

(f) Protection functions and systems.

(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, overcurrent, and loss of synchronism. The applicant shall also provide technical specifications for the generator, lockable interconnection disconnect switch, 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.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.11 Control schematics. For equipment not certified under s. PSC 119.26, the applicant shall include with the application a complete set of control schematics showing all protective functions and controls for generator protection and distribution system protection.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.12 Site plan. For all categories, 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 2, 3, or 4 DG facilities, the site plan shall show the location of major equipment, electric service entrance, electric meter, interconnection disconnect switch, and interface equipment.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

Subchapter III — Design Requirements

PSC 119.20 General design requirements. (1) The applicant shall install protection devices to ensure that the current supplied by the DG facility is interrupted if a fault or other potentially dangerous event occurs on the distribution system. If such an event occurs and the public utility's distribution system is de−energized, any DG facility that is connected to this distribution system shall automatically disconnect. All DG facilities shall utilize protection devices that prevent electrically closing a DG facility that is out of synchronization with the distribution system.

(2) All installations shall include equipment circuit breakers, on the DG facility side of the point where the DG facility is electrically connected to the customer's electrical system, that are capable of interrupting the maximum available fault current. Equipment circuit breakers shall meet all applicable UL, ANSI, and IEEE standards.

(3) 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.

Note: Provisions of the Wisconsin Electrical Safety Code, Volume 2, ch. Comm 16 also apply to these installations.

(4) The applicant shall label the interconnection disconnect switch "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.

(5) The applicant shall install an equipment grounding conductor, in addition to the ungrounded conductors, between the DG facility and the distribution system. The grounding conductors shall be available, permanent, and electrically continuous, shall be capable of safely carrying the maximum fault likely to be imposed on them by the systems to which they are connected, and shall have sufficiently low impedance to facilitate the operation of overcurrent protection devices under fault conditions. All DG transformations shall be multi−grounded. The DG facility may not be designed or implemented such that the earth becomes the sole fault current path.

Note: Grounding practices are also regulated by the Wisconsin Electrical Safety Code Volumes 1 and 2, as found in chs. Comm 16 and PSC 114.

(6) (a) Certified paralleling equipment shall conform to UL 1741 (January 17, 2001 Revision) or an equivalent standard as determined by the commission.

(b) Non−certified paralleling equipment shall conform to the requirements of IEEE 1547.

Note: The UL standards are available at http://ulstandardsinfonet.ul.com, and IEEE standards are available at http://ieee.org. They may also be viewed at the PSCW Library, 610 N. Whitney Way, Madison, WI.

(7) (a) All Category 1 and 2 DG facilities shall be operated at a power factor greater than 0.9.

(b) All Category 3 and 4 DG facilities shall be operated at unity power factor or as mutually agreed between the public utility and applicant.

(8) The DG facility shall not create system voltage or current disturbances that exceed the standards listed in subch. VII of ch. PSC 113.

(9) The applicant shall protect and synchronize its DG facility with the distribution system.

(10) Each DG facility shall include an automatic interrupting device that is listed with a nationally recognized testing laboratory and is rated to interrupt available fault current. The interrupting device shall be tripped by any of the required protective functions.

(11) An applicant for interconnection of a Category 3 or Category 4 facility shall provide test switches as specified by the public utility, to allow for testing the operation of the protective functions without unwiring or disassembling the equipment.

(12) The public utility may require a DG facility to be isolated from other customers by installation of a separate power transformer. When a separate transformer is required, the utility may include its actual cost in the distribution system upgrade costs. The applicant is responsible for supplying and paying for any custom transformer. This requirement does not apply to an induction−type generator with a capacity of 5 kW or less, or to other generating units of 10 kW or less that utilize a line−commutated inverter.

(13) 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.

(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.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.25 Minimum protection requirements. **(1)** Each DG facility shall include protection and anti−islanding equipment to prevent the facility from adversely affecting the reliability or capability of the distribution system. The applicant shall contact the public utility to determine any specific protection requirements.

(2) The protective system functions, which may be met with microprocessor−based multifunction protection systems or discrete relays, are required. Protective relay activation shall not only alarm but shall also trip the generator breaker/contactor.

(3) In addition to anti−islanding protection, a DG facility shall meet the following minimum protection requirements:

(a) A Category 1 DG facility shall include:

1. Over/under frequency function.
2. Over/under voltage function.
3. Overcurrent function.
4. Ground fault protection.

(b) A Category 2, 3, or 4 DG facility shall include:

1. Over/under frequency function.
2. Over/under voltage function.
3. Overcurrent function.
4. Ground fault protection.
5. Synchronism check function.
6. 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.

(4) A DG facility certified pursuant to s. PSC 119.26 shall be deemed to meet the requirements of this section.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

Subchapter IV — Equipment Certification

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.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.27 Non−certified paralleling equipment.

(1) Any DG facility that is not certified under s. PSC 119.26 shall be equipped with protective hardware or software to prevent islanding and to maintain power quality. The applicant shall provide the final design of this protective equipment. The public utility may review and approve the design, types of protective functions, and the implementation of the installation. The applicant shall own the protective equipment installed at its facility.

(2) The applicant shall calibrate any protective system approved under sub.(1) to the specifications of the public utility. The applicant shall obtain prior written approval from the public utility for any revisions to specified protection system calibrations.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

Subchapter V — Testing of DG Facility Installations

PSC 119.30 Anti−islanding test. The public utility may perform an anti−islanding test or observe the automatic shutdown before giving final written approval for interconnection of the DG facility. The anti−islanding test requires that the unit shut down upon sensing the loss of power on the distribution system. This can be simulated by either removing the customer meter or opening a disconnection switch while the generator is operating. Voltage across the customer side of the meter or disconnection switch shall be measured and must be observed to reduce to zero within two seconds after disconnection. The test shall be conducted with the generation as close to its full output as possible. If a voltage is sustained after the disconnection, approval of the installation shall not be given until corrective measures are taken with a subsequent successful shutdown test.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.31 Commissioning tests for paralleling equipment in Categories 2 to 4. The public utility shall provide the acceptable range of settings for the paralleling equipment of a Category 2, 3, or 4 DG facility. The applicant shall program protective equipment settings into this paralleling equipment. The public utility may verify the protective equipment settings prior to allowing the DG facility to interconnect to the distribution system.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.32 Additional test. The public utility or applicant may, upon reasonable notice, re−test the DG facility installation. The party requesting such re-testing shall bear the cost of the re-tests.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.40 Right to appeal. 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.

History: CR 03−003: renum. from PSC 113.0208 and am. Register January 2004 No. 577, eff. 2−1−04.

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BY ELECTRONIC MAIL

April 20, 2007

Ms. Julie Baldwin, and
Mr. Brian Mills
Michigan Public Service Commission
6545 Mercantile Way
Lansing, Michigan 48909

In re: Docket 15113 - 30+ kW Interconnection Standards
Comments of American Transmission Company (ATC)

Dear Ms. Baldwin and Mr. Mills:

This letter responds to your invitation to comment on five policy objectives relating to interconnection standards for distribution-interconnected generators of 30 kW or greater.

In response to the Commission Staff's initial inquiry in Docket No. 15113, ATC urged that the distribution interconnected generator process specifically incorporate consultation with the transmission owner (TO) when generator interconnection with the distribution facilities is requested[1]. ATC noted that, even though generators are connected to the distribution system and not directly to the transmission system, some distribution interconnected generators can affect transmission system operation, reliability and safety.

ATC believes that in most cases where generation seeks to interconnect to distribution voltage facilities, ATC, as the TO, can assess interconnection impacts on the transmission system concurrent with utility studies, and only in some cases will additional study time or the possible construction of mitigation measures be needed to accommodate the interconnection. This aspect of the interconnection evaluation was not previously considered, and ATC is pleased that the suggestion is included (issue 3) for consideration and comment by all other parties.

In this docket, the Commission Staff has expanded its inquiry, and ATC is pleased to provide the following additional comments on the generation to distribution interconnection process.[2]

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[1] For purposes of its comments, ATC defines the terms "distribution" and "distribution facilities" to refer to any facilities that operate at voltages below 50kV. ATC defines the term "transmission" and "transmission facilities" to refer to facilities that operate at 50kV and above.

[2] ATC's comments here are to be taken in light of the Small Generator Interconnection Procedures under Attachment R of the Open Access Transmission and Energy Markets Tariff of the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and the requirements of the Federal Energy Regulatory Commission under the provisions of Order No. 2006. *Standardization of Small Generation Interconnection Agreements and Procedures*, Order No. 2006, 70 Fed.

Issues and ATC comments

Issue 1: Identify reasonable and achievable interconnection time deadlines.

Simply put, most generator-to-distribution (G-D) interconnections will require no transmission system impact study and would likely also not require any transmission impact mitigation. Some interconnections to distribution facilities, however, may have material, adverse impacts on the reliable operation of the adjacent, interconnected transmission system and would “trigger” the need for some form of transmission system impact study[3]. ATC would anticipate that such a study, in most cases, could be completed in 10 to 15 days, and could be done concurrent with the distribution company analysis of its system. A few interconnections, however, could require 90 or more days for impact and mitigation studies. Whether a more detailed analysis would be required, could likely be determined in the first 15 days following receipt of the necessary information concerning the generator and the proposed interconnection. With that determination, the transmission owner could also provide preliminary estimates of scope of the study, the cost of the study and time required to perform the detailed analysis.

ATC proposes two alternative threshold “tests” to determine when consultation with the TO by the distribution utility should be required. These tests are explained below (issue 3.) Distribution interconnected generation, especially in the lower [smaller] range of the 30 kW and above class, would not trigger either of the tests and review by the TP would be unnecessary.

The alternative threshold tests that ATC would recommend are:

Where a single generator request or the aggregation of existing and new generation, measured at the transmission-to-distribution (T-D) point of interconnection, exceeds a) the minimum distribution load or, b) the total connected generation is 10 MVA or greater, transmission consultation should be required. (These are the two alternate tests.) In these cases some, but not most, interconnection requests will require detailed study. [4]

In cases where more study is necessary, the TO should be able to provide a formal response to the distribution utility within 10-15 business days following receipt of certain basic generator-related information regarding the interconnection request. Depending on the analysis and the impact of the generation on the transmission system, the TO response may state that no further analysis is needed, or, alternatively, it would explain the need for further study(s) and provide an estimate of the time necessary to complete the more detailed analysis and the estimated cost of such analysis. Therefore, the rules governing interconnection of distribution-connected generator should recognize that there are limited instances where significantly longer study and construction times may be necessary.

The time to complete a more detailed study may, in some cases, exceed 90 days. This is reasonable because the analysis to be performed would be substantially the same as the analysis required for transmission-connected generation under the MISO Transmission and Energy Markets Tariff Attachments R and X. A study report documenting the system impact and the facilities required

Reg. 34190 (June 13, 2005), 111 FERC ¶ 61,220 (2005), order on reh’g, Order No. 2006-A, 113 FERC ¶ 61,195, 70 Fed. Reg. 71760 (Nov. 30, 2005)

[3] ATC uses the term “impact study” in a manner similar to that used by the Midwest ISO in relation to all generator interconnections. Here, ATC anticipates that the typical system impact study would consider just the impact on transmission system reliability due to altered system flows and can be completed with 10 to 15 days. If a more complex study of the stability of the transmission system before and after the interconnection, as well as the ability of the system to withstand a fault, is required, additional time, as explained further in this reply, would be needed. In the event that the study shows that reliability would be adversely affected, the study would identify those means by which the adverse effects could be ameliorated or otherwise rectified.

[4] ATC notes the very wide range in size of generators that would be affected by “30kW and larger” guidelines. 30 kW is only about 3/1,000 of 10MVA – the size for generators to which a numerical threshold for guidelines recommended by ATC appears below. For reference, the typical land-based wind turbine is no larger than 2 MVA.

to mitigate the impact would be supplied to the distribution utility upon conclusion of the TO study. An example of a generator interconnection report prepared by ATC for a transmission interconnected generator can be found at:

http://oasis.midwestiso.org/documents/ATC/G583_Impact_Study.pdf

Adopting this approach is important for transmission system reliability purposes and is consistent with the interconnection process followed in connection with interconnecting directly to the transmission system. The commission should note that if a distribution-connected generator wants to offer energy into the MISO energy market or be designated as a network resource in the MISO energy market, the generator customer will be required to coordinate their request with the MISO directly according to MISO's tariff and procedures.

Issue 2: Propose a system for determining whether interconnection costs are reasonable, actual costs.

ATC understands the desire by some to have an identified, readily available and uniform process that could help small generators predict development time and costs for a new generator. Unless such a tool includes and explains a wide variation in possible costs of interconnections, it may only invite disputes when unusual circumstances arise. In ATC's experience, the impact that a generator may have on the system to which it interconnects is highly variable. While having a defined process is undoubtedly valuable, it is also valuable to insure that all interested parties have a clear understanding of the impact that a new generator may have on all elements of the interconnected distribution-transmission system as early as possible in the process, so that, in the event that there are significant impacts, they can be addressed and appropriately taken into account by all parties.

In the event that a more detailed study is required, the customer requesting the interconnection should be required to pay the actual costs incurred by the TO to perform the required impact study. Once it is determined, in the initial evaluation, that the generator interconnection may have an impact on the transmission system, the study ATC proposes would determine the nature and extent of those impacts caused by interconnection of the generator; as well as the mitigation measures, i.e., possible changes to the transmission system, that would be required. A study report documenting the system impact and the facilities required to mitigate the impact would be supplied to the distribution utility and to the interconnection customer.

Issue for future consideration

As described below under issue 3, additional cost for study and interconnection mitigation measures is likely to occur in relatively few cases – generally where larger generating units (or a series of smaller ones) are to be interconnected to the distribution system, but which cause transmission system impacts that require mitigation. In such cases, cost assignment depends on several variables, including: 1) whether the generation meets only local needs or exceeds local distribution loads; 2)whether the generator plans to sell into the market; and 3) whether the generation will be available as a network resource.

These characteristics influence the allocation of the cost of transmission system impacts and mitigation. Transmission system impact mitigation costs, i.e., the cost of modifying existing transmission facilities or constructing new facilities is important to the generator customer, the distribution company and the transmission owner. At a minimum, the Commission's rules relating to these costs should harmonize, to the greatest extent possible, with MISO and FERC cost allocation policies. The Commission should consider whether the construction of transmission-related facilities that are required by virtue of the distribution interconnection requires a further inquiry into how those costs are to be allocated among the interested parties.

Issue 3: Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections).

In the process being considered by the Commission, ATC believes that there are circumstances when the local distribution utility should be required to inform the TO of a new distribution-connected generator interconnection request. Although the typical distribution-connected generator will not adversely impact the transmission network, if a single generator or the aggregation of existing and new generation exceeds certain thresholds, a material impact to the transmission system may occur which would affect the reliable operation of the transmission system and potentially affect the ability of the TO to provide reliable service to the local distribution company. The transmission owner analysis can and should occur concurrently with the distribution utility's analysis.

ATC recommends the following thresholds, as measured at the Point of Interconnection between the transmission and distribution system (T-D POI), be used to determine when the local distribution utility should inform the TO of the generator interconnection request. Where the single generator request or the aggregation of existing and new generation, as a measured at the T-D POI, exceeds:

- The minimum distribution load or
- The total connected generation is 10 MVA or greater.

In these instances, additional study will likely be required.

These threshold tests were chose for the following reasons:

1. **Generation exceeds the minimum distribution load.**
   When distribution connected generation exceeds the minimum local load, power will be transmitted onto and through the transmission network. Since power will be flowing on the transmission grid, it is reasonable that the TO should be informed of the request and given time to ensure that there are no adverse impacts due to the distribution-connected generation. If there are adverse impacts as a result of the proposed interconnection, then the appropriate study and identification of mitigating changes to the transmission system need to be identified and installed before the generator is permitted to tender power to the interconnected distribution-transmission network.

2. **The total connected generation is 10 MVA or greater.**
   The 10 MVA level is a regional guideline for various generator testing and reliability matters. ATC is a member of the Midwest Reliability Organization (MRO), which is one of the North American Electric Reliability Corporation (NERC) regional reliability organizations created to implement and monitor compliance with the mandatory NERC Reliability Standards approved by the FERC. The MRO has approved various generator testing guidelines with a minimum 10 MVA threshold for transmission-connected generation to be reported for compliance purposes. This threshold was designed to identify generators that may adversely interact with the remainder of the transmission network .

ATC believes that both tests should be used primarily because the local load at many locations on the transmission network may exceed 10 MW (e.g., paper mills), therefore the use of only the minimum distribution load test would have the potential to permit substantial amounts of generation to become connected to the distribution portion of the interconnected distribution-transmission network and operated in parallel with the transmission network without the TO being permitted to study the impacts and determine if there are any reliability-related impacts associated with that interconnection. Application of both tests assures that such potential situations are identified and the potential reliability assessed in a timely and appropriate manner.

Applying both tests will likely avoid performing analysis on those generators that will not have a material adverse impact on the network, while at the same time identifying those generators that may have such an impact at the earliest possible time. ATC believes, that if those tests are adopted and employed, the most common planning analysis to be performed by the TO on an interconnection request is a steady-state power flow analysis of the thermal and voltage impacts that would be created by interconnecting the new generator. Although there is a potential for transmission system problems or generator instability with any generator interconnection, most interconnection requests covered by this docket will not require this more detailed analysis.

ATC recommends that any interconnection request exceeding either of these thresholds would require a review by the TO. Based on ATC's experience, a detailed analysis by the transmission owner will likely be required only in those instances where the second test, the 10 MVA threshold, is exceeded.

With detailed analysis required in only a few instances, the TO should typically be able to provide a formal response to the distribution utility within 10-15 business days after receiving the necessary information regarding the distribution-connected generator interconnection request. In the instances where the more detailed stability analysis is required (e.g., 10 MVA threshold), ATC would recommend that the TO be required in its response to indicate 1) the nature and extent of the analysis needed; 2) a request that the distribution utility provide the further detailed information required for this study; 3) an estimated cost of the study; and, 4) the expected timeframe to complete the study once the required data has been received. With this information, the distribution company and interconnection customer can evaluate whether to proceed with the interconnection.

In ATC's view, the customer requesting the interconnection should be required to pay the actual costs incurred by the TO to perform this more detailed study because the analysis is complex, time consuming and requires considerable expertise to perform, As ATC has noted, in its experience, the time to complete this more detailed study may exceed 90 days and the cost to complete the study may approach $50,000, which is reasonable given that this analysis would be no different than that required by the Midwest ISO tariff for transmission-connected generation (cf. MISO Transmission and Energy Markets Tariff Attachments R and X). A study report documenting the system impact and the facilities required to mitigate the impact would be supplied to the distribution utility and the generator customer.

Thank you for this opportunity to comment.

Sincerely,

/s/ Jay A. Porter

Jay A. Porter
Manager, Regional Planning
ATC Management Inc.
American Transmissions Company LLC
262-506-6931

30 kW and Larger Interconnection Procedures Workgroup
U-15113

Comments Received

On the

Staff Strawman Proposals dated June 19, 2007

File Contents

MPSC Staff Strawman Proposals
for Improvements to Interconnection Procedures

DRAFT Document
for Discussion at June 19, 2007 Meeting of
30 kW & Larger Interconnection Procedures Workgroup

INTRODUCTION

MPSC Staff has reviewed all comments received to date. In the following strawman proposal, Staff has attempted to accommodate, as best as possible, all comments. Staff presents this strawman proposal with the intention of leading to a productive dialogue and consensus on as many aspects of the proposal as possible.

Staff has categorized all comments into the following major categories:

1. Timelines, and ideas for developing reasonable and achievable timelines;
2. Interconnection costs, and ideas for assuring project developers will pay reasonable and actual costs;
3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.; and,
4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.

In addition to those issues, Staff is researching:

5. Other miscellaneous issues raised in comments, but not covered in one of the previous four topic areas (including: insurance requirements and liabilities; pre-approved equipment lists; etc.); and
6. Possible power factor requirements for interconnected distributed generators.

Here are preliminary MPSC Staff recommendations for consideration. It should be noted that although the focus of this work group is on interconnections for systems 30 kW and larger, many of the concepts being discussed here could also be applicable to systems smaller than 30 kW.

As a matter of general perspective regarding the recommendations that will ultimately issue from this workgroup process, MPSC Staff has a preference for recommendations that can be adopted by consensus, and will improve the existing interconnection procedures to the extent possible, without having to await a new rulemaking proceeding to alter the existing rules. The Commission already noted, however, that some recommendations may require rulemaking, and established a new docket for that purpose, Case No. U-15239.[1] Thus, MPSC Staff has attempted in the following recommendations

[1] February 27, 2007 Order in Cases Nos. U-15113 and U-15239, pp. 6, 7, 9, 10.

to identify whether it believes each recommendation does or does not require rules changes prior to implementation.

MPSC Staff invites review and comment on these recommendations, and will present this information for discussion at a June 19, 2007 meeting at MPSC Offices, Hearing Room A, scheduled for 10 a.m. to noon.

1. Timelines, and ideas for developing reasonable and achievable timelines:

   1.1 Developers or customers may request pre-application meetings with the utility. The pre-application meeting will allow the project developer and/or customer to seek preliminary guidance from the utility regarding engineering and design alternatives, including preferred locations for interconnection (see section 4 in this list, on page 4).

   1.2 Utilities will note the date when an application for interconnection is received, and the utility will notify the applicant within 3 business days, in writing, that the application has been received.

   1.3 Utilities will notify the applicant in writing within 10 business days of the date the application is received, if the application has been determined to be incomplete. If the application is determined to be incomplete, this notification will explain to the applicant what information is missing and will provide adequate direction to the application to allow them to correct any deficiencies in the application.

   1.4 In general, for the time being and until any changes in timelines are completed through a rulemaking procedure, MPSC Staff recommends that the currently adopted interconnection procedures timelines be utilized, with the utility response time tolled during periods when the project is delayed due to events that are outside of the utility's control. Tolling of the utility response time will, in all cases, require notification from the utility to the applicant, in writing, explaining: (a) the date further action on the interconnection process has been delayed; (b) the reason for delay; (c) the party whose action or inaction has resulted in the reason for delay; and (d) what is required to resolve the issue and re-start the interconnection process. When the issue is resolved, then the utility will again notify the applicant, in writing, of the date when the problem or issue has been resolved and the interconnection process continues.

   1.5 Utility companies could stock some equipment that will be commonly used in interconnections. Utilities should first develop lists of commonly used equipment, and work with suppliers to reduce the time required to obtain equipment when it is ordered. Then, to the extent that the costs of stocking equipment are reasonable and prudent, utilities should do so.

MPSC Staff believes action can be taken to implement recommendations 1.1 through 1.5, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

2. Interconnection costs, and ideas for assuring project developers will pay reasonable and actual costs

   2.1 Utilities will develop conceptual cost estimates for representative installations, based on generic interconnection parameters (subject to change based on actual circumstances for a specific project).

   2.2 Utilities shall maintain a list of qualified contractors as required by R 460.487(5).

   2.3 Utilities shall be required to obtain from qualified contractors three bids for the completion of interconnection work, and the customer shall be required to pay the amount associated with lowest of the three bids. The utility may utilize its own personnel to complete the interconnection work, but may not charge the customer more than the amount associated with the lowest of the three competitive bids.

   MPSC Staff believes action can be taken to implement recommendations in 2.1 through 2.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.

   3.1 Utilities should determine whether distribution level interconnections are likely to affect the transmission network. If effects on the transmission system are anticipated, then the utility should notify both the Midwest Independent System Operator (MISO) and the transmission owner (TO) of the interconnection request.

   Both MISO and the TO should be notified if the interconnected distributed generator: (a) is larger than 2 MW; or (b) will be capable of producing generation in excess of the minimum load on the distribution circuit. The utility shall notify the applicant, in writing, both that it has determined there is a need to notify MISO and the TO, and when the utility has completed that notification. Such notification to the three parties shall take place within not more than 10 days of the utility's receipt of a completed interconnection application.

3.2 As part of the notification provided under item 3.1 above, the distribution utility should inform MISO and the TO of the distribution utility's study schedule and the date by which the distribution utility needs information from MISO and the TO, to coordinate studies and consider transmission impacts, if needed. Within the timeframe requested, it is expected that MISO and the TO will notify the distribution utility whether they will be a participant in the study or do not believe additional analysis of the transmission system impacts is warranted at that time.

3.3 The utility should request that MISO and the TO: (a) acknowledge receipt of the notification within not more than three business days; and (b) notify the utility of their interest in participating in system studies within not more than 10 business days.

MPSC Staff believes action can be taken to implement recommendations 3.1 through 3.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239. Staff notes that MPSC does not have regulatory authority over MISO or Michigan transmission owners, who are the subject of recommendation 3.2 and at least partly of recommendation 3.3. Staff understands that MISO and TOs are ready and willing to cooperate with this proposed procedure, and Staff seeks guidance from interested parties about this recommendation.

4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.

4.1 MPSC Staff believes this recommendation must be considered for three different types of interconnection location decisions: (1) on or adjacent to the premises of a single customer; (2) within a small prescribed area defined by the applicant or system developer; and (3) within larger areas identified by the utility company. Whenever possible, the utility company should provide information suitable for decision making regarding (1) and (2) at or as soon as possible following a pre-application meeting with the applicant and/or developer. Information regarding the third type of location decision should be developed by the utility and made available to all interested parties, with updates no less frequent than every 24 months.

4.2 For type (1) decisions, the utility shall notify the customer of interconnection options and the likely costs associated with interconnecting at any reasonable point on or very near to the customer's premises.

4.3 For type (2) decisions, the applicant or system developer will be responsible for letting the utility know the general area where an interconnection is proposed, and/or a choice of possible locations. For example, a project might be proposed for installation anywhere within an area that is a specific distance from a specified point on the utility network, or another project might be proposed for installation at any of several multiple properties all owned or controlled by one entity.

For both type (1) and (2) decisions, the utility shall determine whether system studies are required in order to determine specific information adequate to provide the applicant or developer with reasonably accurate information upon which an interconnection location decision can be made. If the utility determines that further study is required, then the utility should notify the applicant or developer of that fact, and provide a schedule for the completion of that study.

4.4 For type (3) decisions, the utility should develop a map that indicates locations that are most suitable for the interconnection of distributed generation and are most likely to minimize interconnection costs. MPSC Staff is aware of similar efforts at Pacific Gas & Electric (reported in Lovins, et al., 2002, *Small is Profitable*), Commonwealth Edison, and Consolidated Edison, 2006, DSM 'Load Relief' RFP).

MPSC Staff believes action can be taken to implement recommendations 4.1 through 4.4, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

5. Other miscellaneous issues raised in comments

5.1 Liability insurance. Comment from one developer is that additional liability insurance is unnecessary. MPSC Staff notes that insurance provisions are not presently included in Michigan's interconnection rules, but the Commission did approve the interconnection procedures document which explains that insurance and liability will be among those subjects covered in the utility interconnection and operating agreement.

It would be imprudent for a generator not to have ample insurance coverage, but MPSC Staff does not believe the existing rules allow the utility company to require any specific coverage. Interconnection contracts may include a statement to the effect that the generator acknowledges and accepts their potential liability in the event of an accident, however.

MPSC Staff recommends that all interested parties review the Wisconsin PSC Chapter 119 Rules for Interconnecting Distributed Generation Facilities, part PSC 119.05, and consider whether the Wisconsin insurance and indemnification provisions should be applicable for Michigan, too. (See http://www.michigan.gov/documents/mpsc/30_and_Larger_April_20_Comments_194118_7.pdf, pp. 9-10.)

5.2 Streamlining engineering studies. Recommendation is that utilities should make a determination quickly, whether studies are needed. MPSC Staff supports this concept, and believes this goal can be met by incorporating the recommendations listed under 1 through 4, above.

5.3 Simplified one-line diagrams. Recommendation is that the one-line diagrams required by utilities are presently too complex and should allow for further simplification. MPSC Staff seeks further clarification on this issue, and invites interested parties to submit more specific information.

5.4 Standby rates. Recommendation is that standby rates are presently excessive and should be lowered. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this issue in utility rate cases or other appropriate venues. MPSC Staff notes it believes that MISO Midwest Market rates are now available to provide backup power to customers, as needed, in lieu of purchasing standby and backup service from the utility company.

5.5 Criteria/Standards for Grid Interface Equipment. Comments state that requiring utility grade equipment is unnecessary and that industrial grade relays should be sufficient. MPSC Staff believes that decisions about equipment specifications should be determined by the appropriate national or international standards. IEEE 1547 specifies the performance that an interconnected system must meet. For customer-purchased equipment, the requirement should be for the interconnected system to meet performance specifications – subject to utility verification through a witnessed test –, and the customer should have discretion regarding equipment grade.

Comments also recommend that interface equipment be standardized, insofar as that is possible. This issue is addressed in recommendations 1.5 and 2.1.

5.6 Payments/Ownership of Interface Equipment. Recommendation is that the customer should be compensated for the residual value of interconnection equipment, if any, if the customer has paid for the installation of equipment which later turns out not to be needed for that customer's installation (if the generator ceases operation, for example). MPSC Staff recommends that current accounting practices be reviewed in order to determine the practicality of implementing this type of recommendation.

5.7 Utility financial self-interest. Recommendation is to consider how financial incentives can be changed to make utility cooperation with interconnections to be in the financial interest of the utility. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this issue in utility rate cases or other appropriate venues.

6. Possible power factor requirements for interconnected distributed generators

MPSC Staff recommends Michigan apply the general standard that the power factor requirements for distributed generators should match the requirements for customer loads, for the rate under which the distributed generation customer is served. MPSC Staff recommends Michigan utilize this language from the recently approved Maryland interconnection standards:

> Reactive Power
>
> The Interconnection Customer shall design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the power factor range required by the [utility's] applicable tariff for a comparable load customer. [The utility] may also require the Interconnection Customer to follow a voltage or VAR schedule if such schedules are applicable to similarly situated generators in the control area on a comparable basis and have been approved by the Commission. The specific requirements for meeting a voltage or VAR schedule shall be clearly specified in Attachment 4. Under no circumstance shall these additional requirements for reactive power or voltage support exceed the normal operating capabilities of the Small Generator Facility.

Dykema

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July 6, 2007

Ms. Julie Baldwin
Michigan Public Service Commission
PO Box 30221
Lansing, MI 48909-7721

Re: Case No. U-15113/U-15239
30kW and Larger Interconnection Procedures Workgroup

Dear Ms. Baldwin:

Attached are comments by International Transmission Company, d/b/a ITC*Transmission* ("ITC") and Michigan Electric Transmission Company, LLC ("METC") in response to Michigan Public Service Commission Staff's June 19, 2007 Strawman Proposal for improvements to interconnection procedures. ITC and METC own the majority of transmission system in the Lower Peninsula of Michigan. As a transmission asset owner, one of ITC's activities is the interconnection of new generating sources and the reliable transmission of the electricity generated at these facilities.

ITC and METC thank you for the opportunity to offer comments on Staff's Strawman Proposal. Because this is a workgroup, it is ITC's and METC's understanding that its comments do not need to be officially filed in this docket.

If you have any questions, please contact me.

Sincerely,

DYKEMA GOSSETT PLLC

Christine Mason Soneral

Digitally signed by Christine Mason Soneral
DN: cn=Christine Mason Soneral, c=US, o=Dykema Gossett PLLC
Date: 2007.07.06 09:44:06 -04'00'

Christine Mason Soneral

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RESPONSE OF INTERNATIONAL TRANSMISSION COMPANY, d/b/a ITC*TRANSMISSION*, AND MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC TO MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S JUNE 19, 2007 STRAWMAN PROPOSALS FOR IMPROVEMENTS TO INTERCONNECTION PROCEDURES IN CASE NO. U-15113

International Transmission Company, d/b/a ITC*Transmission*, and Michigan Electric Transmission Company, LLC ("METC") state the following regarding the Michigan Public Service Commission ("MPSC") Staff's June 19, 2007 Strawman Proposal for improvements to interconnection procedures:

1. Timelines, and ideas for developing reasonable and achievable timelines:

A. The transmission company must be involved in the generation interconnection process from the initial consultation/pre-application meeting.

B. The transmission company should assess if the new generator(s) will affect the transmission system.

C. The aggregated output of a group of generators in an electrical area is the driving factor to be considered.

D. Transmission design and guidance is only performed by the transmission company so it is essential that transmission be involved in the initial stages of interconnection discussions.

E. Depending on how the generation is planned to be interconnected (to the distribution or transmission system) determines whether MPSC state procedures or Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") Federal Energy Regulatory Commission ("FERC") approved procedures governs.

F. Notification needs to be provided to MISO as it is responsible for regional transmission planning.

2. Interconnection costs, and ideas for assuring project developers will pay reasonable and actual costs.

A. Are these “interconnection costs” or “network upgrade” costs?

1.) Direct assignment.

2.) Network upgrades.

B. Determine if the new generator(s) is(are) connecting at the distribution level (MPSC procedures) or the transmission level (Midwest ISO FERC approved procedures).

C. Follow “decision tree” to determine whether state or federal procedures should be followed.

1.) For transmission level connections, follow the Midwest ISO generation interconnection procedures as contained in Attachments X and R. The transmission company would be involved in this process.

2.) For distribution level connections, follow MPSC procedures. The local distribution utility would be involved in this process and the transmission company would also be involved to the extent the proposed interconnection has an impact on the transmission system.

3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.

A. Consultation with the transmission company needs to occur at the beginning of the process.

B. All generator interconnection notification should be provided to the transmission company.

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ID\CMMA

July 6, 2007

To: Julie Baldwin
Michigan Public Service Commission

Re: Comments on power factor correction for 30kW and Larger Interconnection Procedures Workgroup

Dear Ms. Baldwin,

Thank you for the opportunity to comment on 30 kW interconnection issues. Please find below some general comments regarding the power factor correction issues.

It was observed by participants during the meeting on June 19, 2007 that power factor correction is primarily an economic issue, as the technical factors for correcting generator output are well known and quantifiable. This fact is evident in the past filings of Detroit Edison and Consumers Energy, which contain penalties for poor power factor and incentives for desired power factor, which should be expanded and clarified for the purposes of this workgroup.

I have provided below a short review of power factors which addresses both lagging and leading power factors, some supporting data on power factor treatment, and several suggestions below for fair treatment of all parties on power factor issues.

Power Factor 101

As stated by the DTE presentation, a “unity” power factor of 1.0 is optimal, but realities of load and generator interaction cause this power factor to vary over time. Power factor at a meter can “lag” the grid (i.e. draw extra energy “vars” from the grid), or “lead” the grid (i.e. inject energy “vars” into the grid). Power factors commonly found on power grids range from an undesirable 0.7 lagging, improving towards 0.99 lagging and 1.0 (unity), then transitioning to the less common leading power factors from 0.99 leading to 0.7 leading. One way to form a mental picture of power factor is to view it as the variance from the optimum of 1.0 (unity), which may exhibit a drift in either direction (lagging/leading) until the drift reaches an unacceptable point (e.g. 0.7) and must be corrected.

OpKnowledge
ADVISORS

Utility Treatment of Power Factors

There are acceptable ranges of this leading and lagging which the utilities have included in their rate filings for numerous rates. Let's quickly review those for loads:

Power Factor	DTE Filing	Consumers Filing
Below 0.7 lagging	Can disconnect customer	Can disconnect customer
Between 0.7 to 0.75 lagging	3% financial penalty	Financial penalty calculated below 0.8 power factor
Between 0.75 to 0.8 lagging	2% financial penalty, or $3.50/KVar below 0.8 lagging	Same calculation as above
Between 0.8 to 0.85 lagging	1% financial penalty	No penalty
Between 0.8 to 0.9 lagging	Desired power factor	Desired Power factor
Between 0.9 lagging and 1.0	Not addressed	2% incentive (rebate)
Leading power factor	Not addressed	Not addressed

Financial penalties are typically not addressed for non-excessive leading power factors as these are desirable in most instances as they directly offset (more prevalent) equivalent lagging power factors (i.e. a .8 leading power factor on 30kW directly offsets as .8 lagging power factor on 30kW at the same connection point).

Regarding the treatment of power factor correction from generation connections, one can review FERC Docket No. ER06-348-000, in which a generator in Michigan requested over $1.3MM per year in remuneration from MISO to provide power factor correction on the grid as per Schedule 2 of the MISO tariff. Note that this generator was not expected to generate at unity power factor, and in fact expected to receive guaranteed payment for power factor support.

The above facts demonstrate that there is significant precedent in both financial penalty for undesirable power factors as well as financial incentive for desirable power factors.

Given the above observations, please find below some suggestions for fair and balanced treatment of generation interconnection.

Suggestions for Power Factor Treatment for Interconnections

1. Any party seeking to assess penalties for undesirable power factors should also be required to provide equivalent incentive payments for desirable power factors.

2. Costs that are presented as necessary for correction of power factor should be open for bid by third parties. As an example, the presentation by DTE on June 19, 2007 presents a cost of $20,000 per MVAR for power factor correction. If a third party can offer power factor correction for less than this rate, then they should be encouraged to do so.

3. Generators should not be required to connect at unity power factor, but should have a strong incentive for connection at a desired power factor. A range of penalties and incentives for connection at various power factors should be specified, including bandwidths of power factors as shown in utility rates. Unity power factor should have neither incentives or penalties.

Thank you,

Donald Lechnar

Don.Lechnar@opknowledge-advisors.com

MPSC Staff Strawman Proposals
for Improvements to Interconnection Procedures

DRAFT Document
for Discussion at June 19, 2007 Meeting of
30 kW & Larger Interconnection Procedures Workgroup

INTRODUCTION

MPSC Staff has reviewed all comments received to date. In the following strawman proposal, Staff has attempted to accommodate, as best as possible, all comments. Staff presents this strawman proposal with the intention of leading to a productive dialogue and consensus on as many aspects of the proposal as possible.

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1. Timelines, and ideas for developing reasonable and achievable timelines;
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4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.

In addition to those issues, Staff is researching:

5. Other miscellaneous issues raised in comments, but not covered in one of the previous four topic areas (including: insurance requirements and liabilities; pre-approved equipment lists; etc.); and
6. Possible power factor requirements for interconnected distributed generators.

Here are preliminary MPSC Staff recommendations for consideration. It should be noted that although the focus of this work group is on interconnections for systems 30 kW and larger, many of the concepts being discussed here could also be applicable to systems smaller than 30 kW.

As a matter of general perspective regarding the recommendations that will ultimately issue from this workgroup process, MPSC Staff has a preference for recommendations that can be adopted by consensus, and will improve the existing interconnection procedures to the extent possible, without having to await a new rulemaking proceeding to alter the existing rules. The Commission already noted, however, that some recommendations may require rulemaking, and established a new docket for that purpose, Case No. U-15239.[1] Thus, MPSC Staff has attempted in the following recommendations

[1] February 27, 2007 Order in Cases Nos. U-15113 and U-15239, pp. 6, 7, 9, 10.

to identify whether it believes each recommendation does or does not require rules changes prior to implementation.

Michigan Electric Industry Comments

These comments are the joint effort of the regulated electric utilities including the members the Michigan Electric and Gas Association and the Michigan Electric Cooperative Association as well as DTE Energy (Detroit Edison) and Consumers Energy (collectively "Utilities"). The Staff Strawman proposal is reproduced verbatim in black ink, with the Utility comments in relevant places in blue ink and italicized for non-color printings.

Although this work group process is addressing interconnection of projects sized at 30 kW and up, experience and the type of project developers participating in the process indicate that the focus is still on "smaller" projects, likely to be sized at 2 megawatts (MW) or less. The larger independent generator interconnections tend to be worked out on a project specific basis, without the need for Commission oversight or complaint resolution. The developers of larger projects are typically experienced entities and there are likely to be multiple Utility employees devoted to the project.

MPSC Staff invites review and comment on these recommendations, and will present this information for discussion at a June 19, 2007 meeting at MPSC Offices, Hearing Room A, scheduled for 10 a.m. to noon.

1. Timelines, and ideas for developing reasonable and achievable timelines:

   1.1 Developers or customers may request pre-application meetings with the utility. The pre-application meeting will allow the project developer and/or customer to seek preliminary guidance from the utility regarding engineering and design alternatives, including preferred locations for interconnection (see section 4 in this list, on page 9).

   The general premise of holding a pre-application meeting with a potential Project Developer (PD) or Customer on request is acceptable to Utilities. The pre-application meeting obligation should not be open ended – for a single project the meeting should be limited to not more than two (2) separate occasions or a total of 4 hours. This will encourage advance preparation by PDs and efficient use of time by the Utility employees.

   1.2 Utilities will note the date when an application for interconnection is received, and the utility will notify the applicant within 3 business days, in writing, that the application has been received.

   This is acceptable to Utilities and consistent with the existing Generator Interconnection Requirements (GIR). Reasonable means of electronic

communication such as e-mail and fax should be allowed for this notification.

1.3 Utilities will notify the applicant in writing within 10 business days of the date the application is received, if the application has been determined to be incomplete. If the application is determined to be incomplete, this notification will explain to the applicant what information is missing and will provide adequate direction to the application to allow them to correct any deficiencies in the application.

This is consistent with the existing Generator Interconnection Requirements (GIR); however, actual experience indicates this time period is not sufficient to fully address an application particularly where there are multiple applications and interconnection processes under review by a single Utility. For these larger units the Utilities suggest a time period of 1 month for review and notification of missing information in the application. This will provide an incentive for PDs to make sure the application is complete. In some cases, even a complete application may indicate a need for additional information concerning the project. If preliminary analysis shows such a need, the Utility should advise the PD and be allowed 2 months to respond. The "pre-meeting" process will provide an initial opportunity for information exchange between the parties to mitigate delay.

1.4 In general, for the time being and until any changes in timelines are completed through a rulemaking procedure, MPSC Staff recommends that the currently adopted interconnection procedures timelines be utilized, with the utility response time tolled during periods when the project is delayed due to events that are outside of the utility's control. Tolling of the utility response time will, in all cases, require notification from the utility to the applicant, in writing, explaining: (a) the date further action on the interconnection process has been delayed; (b) the reason for delay; (c) the party whose action or inaction has resulted in the reason for delay; and (d) what is required to resolve the issue and re-start the interconnection process. When the issue is resolved, then the utility will again notify the applicant, in writing, of the date when the problem or issue has been resolved and the interconnection process continues.

The rulemaking time deadlines are proving unworkable in practice and development of more reasonable time periods should not be deferred. The time intervals in the Michigan rules are shorter than those of other states and pose a considerable burden for smaller utilities and cooperatives. The Michigan rules (R 460.486) adopt stated deadlines for completing all of a utility's obligations for interconnection for each of the 5 size category ranges. This approach is more reasonable where a proposed interconnection requires no distribution system modifications (e.g.

typically 10kW and less projects). As generator size increases the likelihood of required system modifications increases. System modifications require longer interconnection timelines. Utilities suggest that the Commission consider the interconnection deadline approach used in Wisconsin's Rule 119 (Attachment No. 1). Rule 119 provides deadlines for steps of the project (engineering review, distribution study and final testing) for the project size categories.

In developing timelines, consideration should be given to situations where there are numerous applications for interconnection exceeding the ability of a Utility to effectively process them consistent with the deadlines. Strict enforcement and sanctions under the present rules should not be adopted because of the experience with many projects requiring additional time.

Utilities support the Strawman concept of tolling the deadlines for circumstances beyond their control. The Michigan rule differs insofar as it recognizes tolling for right-of-way procurement/zoning and PD delays only. The detailed notification requirements suggested in the Strawman could be counterproductive, however. It is reasonable to give notice of tolling and address the reasons. Utilities already track problems that arise with any interconnection project. Requiring a written listing of the reasons, assignment of fault, and actions needed to re-start the clock may lead to an overabundance of caution and excessive formality because the document is likely to become the focal point in any complaint proceeding.

A starting point for discussions leading to improvement of the time deadlines could be the periods and size categories in Wisconsin Rule 119. The Wisconsin size categories could easily be modified to fit the current 5 Michigan categories. The remaining steps in the process involve the utility completing detailed design, engineering, procurement of equipment, right of way, and final construction. The details of these parts of the timeline are not in the Wisconsin rule and need to be addressed..

The current GIR also requires that the utility provide a good faith cost estimate of the project cost immediately after the application is complete, without a study having been completed, and with a two hour consultation. Such a cost estimate is nothing more than a guess. In fact, interconnection of generation projects may actually be infeasible at some locations in the utility and may be rejected pending an interconnection study. Providing a cost estimate at that stage in the process timeline is clearly an unreasonable requirement that should be eliminated.

1.5 Utility companies could stock some equipment that will be commonly used in interconnections. Utilities should first develop lists of commonly used equipment, and work with suppliers to reduce the time required to obtain equipment when it is ordered. Then, to the extent that the costs of stocking equipment are reasonable and prudent, utilities should do so.

Utilities may be able to stock some commonly used equipment with long lead times in an attempt to help expedite the interconnection process. This practice could give rise to other issues, since there are costs associated with stocking commonly used equipment (~7-10% loadings) and the time of use is uncertain. Most PD's will likely view the carrying costs as unreasonable; alternatively, other customers may object to these costs being absorbed by the utility creating a subsidy. The decision to stock items should be left to individual Utilities based on their own policies and experience. The policy should be consistent with the stocking of equipment to assure reliable service for general utility customers.

MPSC Staff believes action can be taken to implement recommendations 1.1 through 1.5, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

As stated above, additional collaboration is warranted in order to develop more reasonable and achievable interconnection timelines. A piecemeal approach may not be the best way to address the interconnection issues, particularly if there is interest in a framework similar to Wisconsin Rule 119.

2. Interconnection costs and ideas for assuring project developers will pay reasonable and actual costs.

This process should not assume PDs are being charged unreasonable or excessive costs. Generally, Utilities provide the interconnection services at their cost, which includes standard overheads. Utilities also provide expertise through their trained personnel and may provide the cost advantage of equipment purchased in bulk.

2.1 Utilities will develop conceptual cost estimates for representative installations, based on generic interconnection parameters (subject to change based on actual circumstances for a specific project).

This proposal acknowledges that project interconnection costs will vary based on the circumstances of individual projects. Thus any generic parameters are likely to vary from actual costs and lead to tension and possible controversy. The conceptual costs will likely be treated as a benchmark for comparison by PDs, if the actual costs turn out to be higher. Utilities would then have an incentive to provide high estimates to protect against future controversy. In the experience of some utilities, PDs are looking for more concrete cost estimates in order to securing

project financing. Lenders are not likely to accept the generic figures without some assurance they are close to the actual costs.

A possible alternative to the proposal would be to hold pre-application meetings, and develop preliminary cost estimates based on proposed sites versus blanket conceptual estimates.

2.2 Utilities shall maintain a list of qualified contractors as required by R 460.487(5).

This is acceptable and consistent with existing practices. Contractors are typically subject to direct utility supervision. Customers are not permitted to work on utility assets.

2.3 Utilities shall be required to obtain from qualified contractors three bids for the completion of interconnection work, and the customer shall be required to pay the amount associated with lowest of the three bids. The utility may utilize its own personnel to complete the interconnection work, but may not charge the customer more than the amount associated with the lowest of the three competitive bids.

As noted, there should be no assumption that PDs are being charged unreasonable and excessive interconnection costs. This recommendation will create multiple new issues and add to the complexity of the interconnection process. The last sentence in particular may give rise to issues under the collective bargaining agreements of utilities. Introducing a competitive bidding process will add all f the difficulties and uncertainties associated with bidding: What happens with "scope creep" after the bid is accepted? Will disgruntled bidders commence litigation? Who should police the fairness of the bidding process?

A competitive bid process eliminates parallel path opportunities and pre-planning during the project engineering. Engineering work packets will need to be 100% complete before the bid package can be submitted to the contractors for bid development. Engineering time may have to be extended to ensure all unknowns are accounted for in the bid package. If additional work is identified during construction, time delays may result from contract change orders, and customer approvals for the change orders. The project would be subject to contractor availability, contractor bids may not be as timely if work is plentiful.

Introducing a competitive bidding process for interconnections will raise an issue of discriminatory pricing vis-à-vis other utility customers. The issue underlying this recommendation relates to utility cost and overheads.

All bundled retail customers are required to pay the accepted accounting overheads on new business, premium service, relocation and system modification projects. The generator should be billed according to the same practices/processes as other Utility customers. For example, if a phase extension is required for the interconnection, the PD should pay the same line extension charges as would apply to another customer seeking phase extension.

MPSC Staff believes action can be taken to implement recommendations in 2.1 through 2.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

For the reasons stated above, implementation of Recommendations 2.1 and 2.3 is not appropriate action.

3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.

3.1 Utilities should determine whether distribution level interconnections are likely to affect the transmission network. If effects on the transmission system are anticipated, then the utility should notify both the Midwest Independent System Operator (MISO) and the transmission owner (TO) of the interconnection request.

Both MISO and the TO should be notified if the interconnected distributed generator: (a) is larger than 2 MW; or (b) will be capable of producing generation in excess of the minimum load on the distribution circuit. The utility shall notify the applicant, in writing, both that it has determined there is a need to notify MISO and the TO, and when the utility has completed that notification. Such notification to the three parties shall take place within not more than 10 days of the utility's receipt of a completed interconnection application.

Utilities would typically make the determination and notify the applicable RTO (MISO, or PJM in the case of Indiana Michigan Power Company) under the RTO's procedures. Notice to the appropriate regional reliability organization may be a consideration. In situations affecting the transmission network, the PD is responsible for interactions with the RTO and TO. The timing for transmission review and studies is beyond the control of the Utilities or Michigan regulation.

3.2 As part of the notification provided under item 3.1 above, the distribution utility should inform MISO and the TO of the distribution utility's study schedule and the date by which the distribution utility needs information from MISO and the TO, to coordinate studies and consider transmission

impacts, if needed. Within the timeframe requested, it is expected that MISO and the TO will notify the distribution utility whether they will be a participant in the study or do not believe additional analysis of the transmission system impacts is warranted at that time.
Any coordination of transmission and distribution studies and related timing issues will need to be worked out among the interested parties on a case-specific basis.

3.3 The utility should request that MISO and the TO: (a) acknowledge receipt of the notification within not more than three business days; and (b) notify the utility of their interest in participating in system studies within not more than 10 business days.

Any coordination of transmission and distribution studies and related timing issues will need to be worked out among the interested parties on a case-specific basis. Utilities have no standing to impose time deadlines on the transmission entities.

MPSC Staff believes action can be taken to implement recommendations 3.1 through 3.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239. Staff notes that MPSC does not have regulatory authority over MISO or Michigan transmission owners, who are the subject of recommendation 3.2 and at least partly of recommendation 3.3. Staff understands that MISO and TOs are ready and willing to cooperate with this proposed procedure, and Staff seeks guidance from interested parties about this recommendation.

These recommendations are affected by the lack of Michigan regulatory authority over the transmission entities, as acknowledged above. Any procedures in this area should be worked out on a voluntary and project specific basis to provide experience regarding what is feasible. It is premature and probably unnecessary to assign PD obligations in dealing with the transmission entities to the Utilities and providing time deadlines to those entities.

4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.

Typically, small generator projects are located at specific existing sites already chosen by the customer, such as the customer's current residence or small business location. As a general rule of thumb, the probability of lower interconnection costs increases as the site is located closer to a substation.

This proposed course of action suggests imposition of an obligation on Utilities to perform engineering study work on behalf of PDs who will then displace Utility load and revenue and seek compensation for excess generation, while assuming none of the public duties associated with public utility service. This is a major public policy issue. Further, Utilities would be placed in the position of assuming significant administrative duties and costs, because the dynamic nature of utility systems would require a constant re-evaluation of the optimal DG locations. Circuits are constantly in a state of flux with load being shifted from one circuit to another, circuits being upgraded or modified, equipment being changed out, etc. It would require a constant and significant effort to update the distribution system status, as affected by time of day, time of year, equipment outages, system load and other factors. Presumably, the costs of this effort would be subsidized by the Utility customer base. Further, with the dynamic system there can be little guarantee that a designated interconnection point will remain optimal from the PD's viewpoint. Thus, the recommendation would create a risk of litigation based on alleged breach of this new "duty" to provide the best location information.

Finally, caution and a concern for public safety and security mitigate against a requirement for the detailed public disclosure of distribution weak points and other system information.

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4.1 MPSC Staff believes this recommendation must be considered for three different types of interconnection location decisions: (1) on or adjacent to the premises of a single customer; (2) within a small prescribed area defined by the applicant or system developer; and (3) within larger areas identified by the utility company. Whenever possible, the utility company should provide information suitable for decision making regarding (1) and (2) at or as soon as possible following a pre-application meeting with the applicant and/or developer. Information regarding the third type of location decision should be developed by the utility and made available to all interested parties, with updates no less frequent than every 24 months.

For the type (1) and type (2) situations, the optimal interconnection point can be addressed through the established procedures, including the pre-application meeting. The type (3) situation is subject to all of the concerns discussed above.

4.2 For type (1) decisions, the utility shall notify the customer of interconnection options and the likely costs associated with interconnecting at any reasonable point on or very near to the customer's premises.

This proposal is generally acceptable, since the customer would be approaching the Utility with a project and a proposed location.

4.3 For type (2) decisions, the applicant or system developer will be responsible for letting the utility know the general area where an interconnection is proposed, and/or a choice of possible locations. For example, a project might be proposed for installation anywhere within an area that is a specific distance from a specified point on the utility network, or another project might be proposed for installation at any of several multiple properties all owned or controlled by one entity.

This proposal is generally acceptable, since the possible location options are determined by the PD and the Utility would then be assisting the PD in its selection of the preferable interconnection point based on the local system.

For both type (1) and (2) decisions, the utility shall determine whether system studies are required in order to determine specific information adequate to provide the applicant or developer with reasonably accurate information upon which an interconnection location decision can be made. If the utility determines that further study is required, then the utility should notify the applicant or developer of that fact, and provide a schedule for the completion of that study.

The PD should have the responsibility of determining what information or study is needed to make its decision on the location of the interconnection. Utilities should not be assigned the duty and responsibility to make project location decisions for the PDs. Interconnection studies (of some degree, even if simple) will be required for any project interconnection.

4.4 For type (3) decisions, the utility should develop a map that indicates locations that are most suitable for the interconnection of distributed generation and are most likely to minimize interconnection costs. MPSC Staff is aware of similar efforts at Pacific Gas & Electric (reported in Lovins, et al., 2002, *Small is Profitable*), Commonwealth Edison, and Consolidated Edison, 2006, DSM 'Load Relief' RFP).

This entire area of "type (3)" decisions is subject to the earlier general comment regarding the roles of the utility and PD as well as concerns for security and cost responsibility. In effect, this recommendation appears to contemplate a major assigned role to Utilities to perform widespread location work on behalf of potential developers, with the costs borne by the utilities and their customers.

MPSC Staff believes action can be taken to implement recommendations 4.1 through 4.4, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

As noted, the Utilities have major concerns over the Type (3) decision proposals in this section.

5. Other miscellaneous issues raised in comments

5.1 Liability insurance. Comment from one developer is that additional liability insurance is unnecessary. MPSC Staff notes that insurance provisions are not presently included in Michigan's interconnection rules, but the Commission did approve the interconnection procedures document which explains that insurance and liability will be among those subjects covered in the utility interconnection and operating agreement.

It would be imprudent for a generator not to have ample insurance coverage, but MPSC Staff does not believe the existing rules allow the utility company to require any specific coverage. Interconnection contracts may include a statement to the effect that the generator acknowledges and accepts their potential liability in the event of an accident, however.

MPSC Staff recommends that all interested parties review the Wisconsin PSC Chapter 119 Rules for Interconnecting Distributed Generation Facilities, part PSC 119.05, and consider whether the Wisconsin insurance and indemnification provisions should be applicable for Michigan, too. (See http://www.michigan.gov/documents/mpsc/30_and_Larger_April_20_Comments_194118_7.pdf, pp. 9-10.)

Many of the Utilities participating in these comments agree that the provisions for minimum liability insurance and indemnity contained in Wisconsin Rule 119.05 are workable. It is well known in Michigan that the potential liability for tort damages can be greatly influenced by the venue; accordingly, the minimum insurance coverage should be adjusted for this increased risk, for those utilities rendering service in the higher risk areas. For example, Attachment 2 contains the insurance and indemnity requirements proposed for DTE Energy. This should be discussed in the collaborative. Another approach is simply to leave this issue to each utility, subject to a general requirement of commercial reasonableness in accordance with local practices. In either case, there should be requirements applicable to the PD (installer) and the customer owning the generator during its time of use.

5.2 Streamlining engineering studies. Recommendation is that utilities should make a determination quickly, whether studies are needed. MPSC Staff supports this concept, and believes this goal can be met by incorporating the recommendations listed under 1 through 4, above.

This recommendation needs further clarification because the terms "streamlining" and "quickly" are susceptible to conflicting interpretations.

There should be no regulatory action that diminishes the quality of the engineering studies for interconnection. Engineering studies are required for all interconnection projects. A "cookbook" approach cannot be implemented without degrading the quality of the studies. The characteristics of the utility system are too diverse, generator size can be practically anything, and electric systems are complex. To decrease the engineering study time, the generator needs to provide the information specified in the interconnect application.

The existing MPSC Interconnection Standards are written such that the engineering study contains the analysis, system modification requirements and conceptual costs as one package – unlike other states that break the same analysis into several steps of the process, such as Wisconsin (Rule 119).

5.3 Simplified one-line diagrams. Recommendation is that the one-line diagrams required by utilities are presently too complex and should allow for further simplification. MPSC Staff seeks further clarification on this issue, and invites interested parties to submit more specific information.

A one-line diagram is a simplified electrical drawing. The information required on the one-line diagrams is important for understanding the project design, operation, protection scheme, etc. A complete one-line diagram can significantly speed up an engineering analysis / study / project. The information required on the one-line diagram is what the utility needs to complete a study. Oversimplification will create risks to the safety of linemen and the public.

5.4 Standby rates. Recommendation is that standby rates are presently excessive and should be lowered. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this issue in utility rate cases or other appropriate venues. MPSC Staff notes it believes that MISO Midwest Market rates are now available to provide backup power to customers, as needed, in lieu of purchasing standby and backup service from the utility company.

If Staff is taking the absolute position that standby rates are presently excessive and should be lowered, how does this accord with recent electric rate case orders approved by the Commission? There may be some confusion whether MISO provides a standby service available for retail electric customers with a small on-site generator. MISO's "station service" is designed for large electric generators with energy sales into the MISO market. Utilities disagree with the general assertion that standby rates are excessive and should be lowered. These rates are established under the general cost of service ratemaking approach.

5.5 Criteria/Standards for Grid Interface Equipment. Comments state that requiring utility grade equipment is unnecessary and that industrial grade relays should be sufficient. MPSC Staff believes that decisions about equipment specifications should be determined by the appropriate national or international standards. IEEE 1547 specifies the performance that an interconnected system must meet. For customer-purchased equipment, the requirement should be for the interconnected system to meet performance specifications – subject to utility verification through a witnessed test –, and the customer should have discretion regarding equipment grade.

Utilities must be able to control the operation, modification and maintenance of their own electric systems, which are unique and have evolved over time due to technology changes, equipment availability, service requirements and customer needs. A customer or developer cannot be provided the discretion to determine the grade of equipment they wish to connect directly to or on a utility's electrical distribution system. A utility must have the discretion to require the type and grade of equipment on its electrical system it believes to be most appropriate. While a piece of equipment described as "industrial grade" sounds robust, it may have considerably less reliability, durability or capability than a similar "utility grade" piece of equipment. Utilities are held accountable to maintain certain levels of system reliability and therefore must be permitted to control the type of equipment on their electrical systems. PD's may install protective relays of any grade the choose in order to protect their own equipment.

Comments also recommend that interface equipment be standardized, insofar as that is possible. This issue is addressed in recommendations 1.5 and 2.1.

5.6 Payments/Ownership of Interface Equipment. Recommendation is that the customer should be compensated for the residual value of interconnection equipment, if any, if the customer has paid for the installation of equipment which later turns out not to be needed for that customer's installation (if the generator ceases operation, for example). MPSC Staff recommends that current accounting practices be reviewed in order to determine the practicality of implementing this type of recommendation.

There will be little or no residual value to the utility for interconnection-related equipment (such as transfer trip, monitoring device, etc). This equipment is needed solely for the customer's interconnection. Furthermore, rates are based upon the cost of service and a regulated rate of return. The distribution cost does not decrease because a customer's generating unit shuts down. Providing compensation for residual value would shift cost from the customer that caused the cost to other customers

that did not cause the cost. This is a sunk cost of the customer's generation project, not unlike any other electrical work performed on the customer's premises that has little or no value after the generator ceases operation.

5.7 Utility financial self-interest. Recommendation is to consider how financial incentives can be changed to make utility cooperation with interconnections to be in the financial interest of the utility. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this issue in utility rate cases or other appropriate venues.

The statement implies without foundation that utilities are not cooperating with interconnections due to their financial interests. While the issue may indeed by beyond the scope of the process, it is noteworthy that many interconnections are mandated by law and cooperation is required. Lack of cooperation should not be assumed based on the efforts of utilities to recover the costs associated with providing a premium service to the PDs.

6. Possible power factor requirements for interconnected distributed generators

MPSC Staff recommends Michigan apply the general standard that the power factor requirements for distributed generators should match the requirements for customer loads, for the rate under which the distributed generation customer is served. MPSC Staff recommends Michigan utilize this language from the recently approved Maryland interconnection standards:

Reactive Power

The Interconnection Customer shall design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the power factor range required by the [utility's] applicable tariff for a comparable load customer. [The utility] may also require the Interconnection Customer to follow a voltage or VAR schedule if such schedules are applicable to similarly situated generators in the control area on a comparable basis and have been approved by the Commission. The specific requirements for meeting a voltage or VAR schedule shall be clearly specified in Attachment 4. Under no circumstance shall these additional requirements for reactive power or voltage support exceed the normal operating capabilities of the Small Generator Facility.

The proposed matching principle (generator and load customer) is misplaced because the parties are not similarly situated. A load customer pays a regulated rate for electric service that includes costs of Power Factor correction supplied by the utility. A generator is not paying the Power Factor costs through the regulated rates; therefore the proposed "matching" actually creates a subsidy,

since the costs of Power Factor correction caused by the generator are passed on to the Utility and its other customers.

The Maryland Reactive Power provision cited only addresses the electrical design of the generation facility but does not address the real consequences of operating generation equipment outside of the relevant limits. Failure to operate a generator as required causes additional costs to the utility which, if not compensated by the customer who causes the cost, will ultimately be passed on to other electric customers. Accordingly, Utilities will provide adequate VAR compensation for inadequate power factor of the generator. Utilities will invoice the PD at the time of initial interconnection of the generator.

The power factor for the distributed generation installation must be set in a manner to insure proper anti-islanding separation, to minimize risks to the public and equipment of other utility customers. IEEE 1547 4.4.1 prohibits the distributed resource from causing variances in the local utility service voltage beyond established ranges. For weak local systems and rural systems, the service quality issues associated with voltage regulation and islanding can be difficult to resolve, sometimes requiring additional equipment at the project developer's expense. Utilities are expected to prevent the addition of customers or facilities from unduly impacting or degrading the quality of service to others. The proposal conflicts with this expectation and duty.

Attachment No. 1
Wisconsin Rule 119

Unofficial Text (See Printed Volume). Current through date and Register shown on Title Page.

Chapter PSC 119

RULES FOR INTERCONNECTING DISTRIBUTED GENERATION FACILITIES

Subchapter I — General

PSC 119.01 Scope. This chapter implements s. 196.496, Stats. It applies to all DG facilities with a capacity of 15 MW or less that are interconnected, or whose owner seeks to have interconnected, to an electric public utility's distribution system. It also applies to all electric public utilities to whose distribution systems a DG facility is interconnected, or to which interconnection is sought. These rules establish uniform statewide standards for the interconnection of DG facilities to an electric distribution system.

History: **CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.**

PSC 119.02 Definitions. In this chapter:

(1) "ANSI" means American National Standards Institute.

(2) "Applicant" means the legally responsible person applying to a public utility to interconnect a DG facility to the public utility's distribution system.

(3) "Application review" means a 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.

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

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

(6) "Category 3" means a DG facility of greater than 200 kW and not more than 1 MW.

(7) "Category 4" means a DG facility of greater than 1 MW and not more than 15 MW.

(8) "Certified equipment" means a generating, control or protective system that has been certified by a nationally recognized testing laboratory as meeting acceptable safety and reliability standards.

(9) "Commission" means the public service commission of Wisconsin.

(10) "Commissioning test" means the process of documenting and verifying the performance of a DG facility so that it operates in conformity with the design specifications.

(11) "Customer" means any person who is receiving electric service from a public utility's distribution system.

(12) "DG" means distributed generation.

(13) "DG facility" has the meaning given in s. 196.496 (1), Stats.

(14) "Distribution feeder" means an electric line from a public utility substation or other supply point to customers that is operated at 50 kV or less, or as determined by the commission.

(15) "Distribution system" means all electrical wires, equipment, and other facilities owned or provided by a public utility that are normally operated at 50 kV or less.

(16) "Distribution system study" means a study to determine if a distribution system upgrade is needed to accommodate the proposed DG facility and to determine the cost of any such upgrade.

(17) "Engineering review" means a study that may be undertaken by a public utility, in response to its receipt of a completed standard application form for interconnection, to determine the suitability of the installation.

(18) "Fault" means an equipment failure, conductor failure, short circuit, or other condition resulting from abnormally high amounts of current from the power source.

(19) "IEEE" means Institute of Electrical and Electronics Engineers.

(20) "Interconnection" means the physical connection of a DG facility to the distribution system so that parallel operation can occur.

(21) "Interconnection disconnect switch" means a mechanical device used to disconnect a DG facility from a distribution system.

(22) "Inverter" means a machine, device, or system that converts direct current power to alternating current power.

(23) "Islanding" means a condition on the distribution system in which a DG facility delivers power to customers using a portion of the distribution system that is electrically isolated from the remainder of the distribution system.

(24) "kV" means kilovolt.

(25) "kW" means kilowatt.

(26) "Material modification" means any modification that changes the maximum electrical output of a DG facility or changes the interconnection equipment, including:

(a) Changing from certified to non–certified devices.

(b) Replacing a component with a component of different functionality or UL listing.

(27) "MW" means megawatt.

(28) "Nationally recognized testing laboratory" means any testing laboratory recognized by the U.S. Department of Labor Occupational Safety and Health Administration's accreditation program.

Note: A list of nationally recognized testing laboratories is available at www.osha.gov/dts/otpca/nrtl/index.html.

(29) "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.

(30) "Parallel operation" means the operation, for longer than 100 milliseconds, of an on–site DG facility while the facility is connected to the energized distribution system.

(31) "Paralleling equipment" means the generating and protective equipment system that interfaces and synchronizes a DG facility with the distribution system.

(32) "Point of common coupling" means the point where the electrical conductors of the distribution system are connected to the customer's conductors and where any transfer of electric power between the customer and the distribution system takes place.

(33) "Public utility" has the meaning given in s. 196.01 (5), Stats.

(34) "Standard application form" means PSC Form 6027 for Category 1 DG facilities or PSC Form 6028 for Category 2 to 4 DG facilities.

(35) "Standard interconnection agreement" means PSC Form 6029 for Category 1 facilities or PSC Form 6030 for Category 2 to 4 DG facilities.

Note: A copy of PSC Forms 6027 to 6030 can be obtained at no charge from your local electric utility or from the Public Service Commission, PO Box 7854, Madison, WI 53707–7854.

(36) "Telemetry" means transmission of DG operating data using telecommunications techniques.

(37) "UL" means Underwriters Laboratory.

(38) "Working day" has the meaning given in s. 227.01 (14), Stats.

History: **CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.**

Subchapter II — General Requirements

PSC 119.03 Designated point of contact. Each public utility shall designate one point of contact for all customer inquiries related to DG facilities and from which interested parties can obtain installation guidelines and the appropriate standard commission application and interconnection agreement forms. Each public utility shall have current information concerning its DG point of contact on file with the commission.

History: **CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.**

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 5 working days, its guidelines and the appropriate standard application form.

(2) The applicant shall complete and submit the standard application form to its public utility.

(3) Within 10 working days of receiving a new or revised application, the public utility shall notify the applicant whether the application is complete.

(4) Within 10 working days of determining that the application is complete, the public utility shall complete its application review. 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, 10 working days.

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

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

(d) Category 4 DG application, 40 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, 60 working days unless a different time period is mutually agreed upon.

(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 10 working days, for a Category 1 or 2 DG project, or 20 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.

(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 5 working days, for a Category 1 DG project, or within 10 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.

History: **CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.**

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. 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

Category	Generation Capacity	Minimum Liability Insurance Coverage
1	20 kW or less	$300,000
2	Greater than 20 kW to 200 kW	$1,000,000
3	Greater than 200 kW to 1 MW	$2,000,000
4	Greater than 1 MW to 15 MW	Negotiated

(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.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.06 Modifications to the DG facility. The applicant shall notify the public utility of plans for any material modification to the DG facility by providing at least 20 working days of advance notice for a Category 1 DG facility, 40 working days for Category 2 DG facility, and 60 working days for a Category 3 or 4 DG facility. The applicant shall provide this notification by submitting a revised standard application form and such supporting materials as may be reasonably requested by the public utility. The applicant may not commence any material modification to the DG facility until the public utility has approved the revised application, including any necessary engineering review or distribution system study. The public utility shall indicate its written approval or rejection of a revised application within the number of working days shown in the table below. Upon completion of the application process, a new standard interconnection agreement shall be signed by both parties prior to parallel operation. If the public utility fails to respond in the time specified in Table 119.06–1, the completed application is deemed approved.

Table 119.06–1

Category	Generation Capacity after Modification	Working Days for Utility's Response to Proposed Modifications
1	20 kW or less	20
2	Greater than 20 kW to 200 kW	40
3	Greater than 200 kW to 1 MW	60
4	Greater than 1 MW to 15 MW	60

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

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.

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.

Table 119.08–1

Category	Generation Capacity	Application Review Fee	Engineering Review Fee	Distribution System Study Fee
1	20 kW or less	None	None	None
2	Greater than 20 kW to 200 kW	$250	Max. $500	Max. $500
3	Greater than 200 kW to 1 MW	$500	Cost based	Cost based
4	Greater than 1 MW to 15 MW	$1000	Cost based	Cost based

(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.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.09 Disconnection. A public utility may refuse to connect or may disconnect a DG facility from the distribution system only under any of the following conditions:

(1) Lack of approved standard application form or standard interconnection agreement.

(2) Termination of interconnection by mutual agreement.

(3) Non–compliance with the technical or contractual requirements.

(4) Distribution system emergency.

(5) Routine maintenance, repairs, and modifications, but only for a reasonable length of time necessary to perform the required work and upon reasonable notice.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.10 One–line schematic diagram.

(1) The applicant shall include a 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.

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

(f) Protection functions and systems.

(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, overcurrent, and loss of synchronism. The applicant shall also provide technical specifications for the generator, lockable interconnection disconnect switch, 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.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.11 Control schematics. For equipment not certified under s. PSC 119.26, the applicant shall include with the application a complete set of control schematics showing all protective functions and controls for generator protection and distribution system protection.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.12 Site plan. For all categories, 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 2, 3, or 4 DG facilities, the site plan shall show the location of major equipment, electric service entrance, electric meter, interconnection disconnect switch, and interface equipment.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

Subchapter III — Design Requirements

PSC 119.20 General design requirements. (1) The applicant shall install protection devices to ensure that the current supplied by the DG facility is interrupted if a fault or other potentially dangerous event occurs on the distribution system. If such an event occurs and the public utility's distribution system is de–energized, any DG facility that is connected to this distribution system shall automatically disconnect. All DG facilities shall utilize protection devices that prevent electrically closing a DG facility that is out of synchronization with the distribution system.

(2) All installations shall include equipment circuit breakers, on the DG facility side of the point where the DG facility is electrically connected to the customer's electrical system, that are capable of interrupting the maximum available fault current. Equipment circuit breakers shall meet all applicable UL, ANSI, and IEEE standards.

(3) 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.

Note: Provisions of the Wisconsin Electrical Safety Code, Volume 2, ch. Comm 16 also apply to these installations.

(4) The applicant shall label the interconnection disconnect switch "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.

(5) The applicant shall install an equipment grounding conductor, in addition to the ungrounded conductors, between the DG facility and the distribution system. The grounding conductors shall be available, permanent, and electrically continuous, shall be capable of safely carrying the maximum fault likely to be imposed on them by the systems to which they are connected, and shall have sufficiently low impedance to facilitate the operation of overcurrent protection devices under fault conditions. All DG transformations shall be multi–grounded. The DG facility may not be designed or implemented such that the earth becomes the sole fault current path.

Note: Grounding practices are also regulated by the Wisconsin Electrical Safety Code Volumes 1 and 2, as found in chs. Comm 16 and PSC 114.

(6) (a) Certified paralleling equipment shall conform to UL 1741 (January 17, 2001 Revision) or an equivalent standard as determined by the commission.

(b) Non–certified paralleling equipment shall conform to the requirements of IEEE 1547.

Note: The UL standards are available at http://ulstandardsinfonet.ul.com, and IEEE standards are available at http://ieee.org. They may also be viewed at the PSCW Library, 610 N. Whitney Way, Madison, WI.

(7) (a) All Category 1 and 2 DG facilities shall be operated at a power factor greater than 0.9.

(b) All Category 3 and 4 DG facilities shall be operated at unity power factor or as mutually agreed between the public utility and applicant.

(8) The DG facility shall not create system voltage or current disturbances that exceed the standards listed in subch. VII of ch. PSC 113.

(9) The applicant shall protect and synchronize its DG facility with the distribution system.

(10) Each DG facility shall include an automatic interrupting device that is listed with a nationally recognized testing laboratory and is rated to interrupt available fault current. The interrupting device shall be tripped by any of the required protective functions.

(11) An applicant for interconnection of a Category 3 or Category 4 facility shall provide test switches as specified by the public utility, to allow for testing the operation of the protective functions without unwiring or disassembling the equipment.

(12) The public utility may require a DG facility to be isolated from other customers by installation of a separate power transformer. When a separate transformer is required, the utility may include its actual cost in the distribution system upgrade costs. The applicant is responsible for supplying and paying for any custom transformer. This requirement does not apply to an induction–type generator with a capacity of 5 kW or less, or to other generating units of 10 kW or less that utilize a line–commutated inverter.

(13) 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.

(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.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.25 Minimum protection requirements. **(1)** Each DG facility shall include protection and anti–islanding equipment to prevent the facility from adversely affecting the reliability or capability of the distribution system. The applicant shall contact the public utility to determine any specific protection requirements.

(2) The protective system functions, which may be met with microprocessor–based multifunction protection systems or discrete relays, are required. Protective relay activation shall not only alarm but shall also trip the generator breaker/contactor.

(3) In addition to anti–islanding protection, a DG facility shall meet the following minimum protection requirements:

(a) A Category 1 DG facility shall include:

1. Over/under frequency function.
2. Over/under voltage function.
3. Overcurrent function.
4. Ground fault protection.

(b) A Category 2, 3, or 4 DG facility shall include:

1. Over/under frequency function.
2. Over/under voltage function.
3. Overcurrent function.
4. Ground fault protection.
5. Synchronism check function.
6. 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.

(4) A DG facility certified pursuant to s. PSC 119.26 shall be deemed to meet the requirements of this section.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

Subchapter IV — Equipment Certification

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.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.27 Non–certified paralleling equipment. **(1)** Any DG facility that is not certified under s. PSC 119.26 shall be equipped with protective hardware or software to prevent islanding and to maintain power quality. The applicant shall provide the final design of this protective equipment. The public utility may review and approve the design, types of protective functions, and the implementation of the installation. The applicant shall own the protective equipment installed at its facility.

(2) The applicant shall calibrate any protective system approved under sub.(1) to the specifications of the public utility. The applicant shall obtain prior written approval from the public utility for any revisions to specified protection system calibrations.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

Subchapter V — Testing of DG Facility Installations

PSC 119.30 Anti–islanding test. The public utility may perform an anti–islanding test or observe the automatic shutdown before giving final written approval for interconnection of the DG facility. The anti–islanding test requires that the unit shut down upon sensing the loss of power on the distribution system. This can be simulated by either removing the customer meter or opening a disconnection switch while the generator is operating. Voltage across the customer side of the meter or disconnection switch shall be measured and must be observed to reduce to zero within two seconds after disconnection. The test shall be conducted with the generation as close to its full output as possible. If a voltage is sustained after the disconnection, approval of the installation shall not be given until corrective measures are taken with a subsequent successful shutdown test.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.31 Commissioning tests for paralleling equipment in Categories 2 to 4. The public utility shall provide the acceptable range of settings for the paralleling equipment of a Category 2, 3, or 4 DG facility. The applicant shall program protective equipment settings into this paralleling equipment. The public utility may verify the protective equipment settings prior to allowing the DG facility to interconnect to the distribution system.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.32 Additional test. The public utility or applicant may, upon reasonable notice, re–test the DG facility installation. The party requesting such re-testing shall bear the cost of the re-tests.

History: CR 03–003: cr. Register January 2004 No. 577, eff. 2–1–04.

PSC 119.40 Right to appeal. 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.

History: CR 03–003: renum. from PSC 113.0208 and am. Register January 2004 No. 577, eff. 2–1–04.

I. INDEMNIFICATION.

(Note: "Project Developer" and/or "Customer" should be defined for the intent to be one and the same or 2 different parties to be clarified throughout. The terms "Customer" and "Company" have been used in this document, but may need to be modified based on how the parties are defined).

17. INDEMNIFICATION

A. Customer covenants and agrees that it shall defend, indemnify and hold Company, and all of its officers, agents and employees harmless for any claim, loss, damage, cost, charge, expense, lien, settlement or judgment, including interest thereon, whether to any person, including employees of Customer, its Subcontractors and Suppliers, or property or both, arising directly or indirectly out of or in connection with Customer's or any of its Subcontractor's or Suppliers performance of the Agreement or in connection with the performance of the Agreement, to which Company or any of its officers, agents or employees may be subject or put by reason of any act, action, neglect or omission on the part of Customer, any of its Subcontractors or Suppliers or Company, or any of their respective officers, agents and employees. Without limiting the foregoing, said obligation includes claims involving Customer's, Supplier's or Subcontractor's employees injured while going to and from the premises. If the Agreement is one subject to the provisions MCL 691.991, then Customer shall not be liable under this section for damage to persons or property directly caused or resulting from the sole negligence of Company, or any of its officers, agents or employees.

B. In the event any suit or other proceedings for any claim, loss, damage, cost, charge or expense covered by Customer's foregoing indemnity should be brought against Company or any of its officers, agents or employees, Customer hereby covenants and agrees to assume the defense thereof and defend the same at Customer's own expense and to pay any and all costs, charges, attorney's fees, and other expenses, and any and all judgments that may be incurred by or obtained against Company or any of its officers, agents, or employees in such suits or other proceedings. In the event of any judgment or other lien being placed upon the property of Company in such suits or other proceedings, Customer shall at once cause the same to be dissolved and discharged by giving bond or otherwise.

II. Insurance

18. Customer shall provide Detroit Edison with Certificate(s) of Insurance evidencing that insurance coverages of the types and amounts as specified in the Appendix to the Agreement entitled “Insurance to be provided by Customer” are in effect.

Customer affirms to Detroit Edison that such insurance coverage will remain in effect during the installation of customer-generator’s facility.

Insurance to be Provided by the Contractor/Supplier (CONTRACTOR)

Before the CONTRACTOR or their Subcontractors DO ANY WORK under the Contract, the CONTRACTOR SHALL FURNISH TO DTE Energy and its subsidiaries CERTIFICATE(S) OF INSURANCE evidencing that insurance has been provided to meet, at minimum, the requirements as set forth in this Appendix. It is expressly understood that the obtaining or maintenance of insurance as is herein required, shall in no way limit or release CONTRACTOR's or Subcontractor's liability under the indemnification provisions of the agreement or contract for which this insurance is provided.

Type of Insurance	Minimum Limits and Coverage
1. Workers' Compensation:	Statutory requirements for the State of Michigan and/or for the state where the work will be performed.
2. Employers' Liability:	$ 1,000,000 each person
3. Business Automobile Policy when applicable (see Section 8.(e) herein). Applies to Owned, Non-Owne and Hired: Combined Single Limit Bodily Injury and Property Damage	$5,000,000 each occurrence
4. Commercial General Liability (The limits required may be satisfied by a combination of primary and/or excess coverage): Combined Single Limit Bodily Injury and Property Damage	$5,000,000 each occurrence
If overhead electric line work, tree trimming/line clearance or attaching to utility poles: Combined Single Limit Bodily Injury and Property Damage	$10,000,000 each occurrence

AND

CONTRACTOR'S and/or its Subcontractors' COVERAGE SHALL:

(i) Include DTE Energy and its subsidiaries as additional insured. Such additional insured status shall be provided by an endorsement at least as broad as the appropriate Insurance Services Office (ISO) endorsement (See Section 6. herein).
(ii) Include a cross liability clause.
(iii) Provide that insurers who satisfy these requirements may not cancel, non-renew, materially alter or reduce coverage or limits unless they have delivered thirty (30) day's prior written notice to Corporate Insurance, DTE Energy.
(iv) Be primary to any potentially applicable insurance carried by or arranged for DTE Energy and its subsidiaries.
(v) Provide that the contractor's insurer shall have no rights of recovery, by subrogation or otherwise, against DTE Energy and its subsidiaries.
(vi) Include blanket contractual coverage.
(vii) Include products and/or completed operations coverage for a period of at least two (2) years after the completion of the service or work
(viii) If it is applicable or becomes applicable to the work under the Contract, provide Professional Liability Insurance and/or Errors & Omissions Liability Insurance with combined single limits of at least $5,000,000 (satisfied by separate policy if needed).
(ix) Contain no exclusions for explosion, collapse or underground property damage hazards (XCU coverage).
(x) If it is applicable or becomes applicable to the work under the Contract, provide Pollution/Environmental Impairment Liability Insurance with limits of at least $5,000,000 per occurrence (satisfied by separate policy if needed).

Insurance to be Provided by the Contractor/Supplier (CONTRACTOR)

5. Initial certificates of insurance and other evidence of coverage are to be provided to the buyer in the supply chain and become a part of the Contract. All Contractor's certificates of insurance shall state in the Special Provisions section: "DTE Energy and its subsidiaries are additional insureds and the above listed liability insurance includes blanket contractual coverage". All certificates must also state that no material change or cancellation can be effective without thirty (30) days prior written notice to Supply Chain, DTE Energy. Immediately upon renewal, rewrite or new issue of its insurance coverage, Contractor shall provide to Supply Chain all such certificates of insurance and other evidence of coverage to satisfy all of the provisions herein. Such certificates should be sent to Supply Chain, RE: Contractor Certificate, DTE Energy, 2000 2nd Avenue, 505 WCB, Detroit, MI 48226.

6. In addition to providing certificates of insurance, Contractor shall provide a copy of its broad additional insured endorsement (or that section of its policy) that states that DTE Energy and its subsidiaries are additional insureds on Contractor's liability policies (see Section 4.(i) herein).

7. Contractor expressly understands and agrees that any discussion, negotiation or acceptance of a certificate of insurance by DTE Energy and its subsidiaries is expressly understood NOT to constitute a review or approval of the CONTRACTOR's or Subcontractor's insurer, insurance coverage or available limits, or a waiver or modification of any of the insurance requirements described herein.

8. Should any of the work:

   (a) Be upon or contiguous to navigable bodies of water or subject to Admiralty jurisdiction, CONTRACTOR and/or its Subcontractors shall also carry insurance covering their employees for benefits available and insurance against employer's liabilities under the Federal Longshoremen's and Harbor Workers' Act (44 U.S. Stat. 1424 (as amended)) and under the Jones Act (41 U.S. Stat. 988 (as amended)) or under the General Maritime Law.
   (b) Involve watercraft owned, hired or operated by the CONTRACTOR and/or its Subcontractors, CONTRACTOR and/or its Subcontractors shall also provide coverage for liability arising out of such watercraft with a combined single limit not less than $5,000,000 each occurrence. If the hull is insured, such insurance shall contain the insurer's waiver of subrogation rights against DTE Energy and its subsidiaries. All relevant provisions of these insurance requirements also apply to this specific requirement.
   (c) Involve aircraft (fixed wing or helicopter) owned, hired or operated by the CONTRACTOR and/or its Subcontractors, then CONTRACTOR and/or its Subcontractors shall also provide coverage for liability arising out of such aircraft with a combined single limit of not less than $50,000,000 each occurrence and such limit shall apply to Bodily Injury (including passengers) and Property Damage. If the craft is insured, such insurance shall contain the insurer's waiver of subrogation rights against DTE Energy and its subsidiaries. All relevant provisions of these insurance requirements also apply to this specific requirement.
   (d) Involve licensed vehicle(s) utilized within the scope of work performed under the Contract, CONTRACTOR and/or its Subcontractors shall provide evidence of Automobile Liability Insurance coverage as outlined in Section 3 herein.
   (e) Involve interstate or intrastate transportation of hazardous cargoes as defined by the Motor Carrier Act of 1980 (as amended), CONTRACTOR and/or its Subcontractors shall provide evidence of compliance with the financial responsibility requirements of the Motor Carrier Act (Form MCS-90 or guarantee bond (as amended)).
   (f) Be within 50 feet of any railroad property, CONTRACTOR and its subcontractors shall each maintain a Railroad Protective Liability Insurance Policy naming the railroad(s) as named insureds, for an amount of not less than the greater of $5,000,000 per occurrence or the limit of insurance required by the owner of the railroad property.

9. The provisions of the various insurance policies and the insurers issuing such policies are subject to DTE Energy's and/or its subsidiaries' approval and a copy of the applicable insurance policies shall be furnished by the CONTRACTOR at the request of DTE Energy and/or its subsidiaries.

10. All deductibles or retentions on any of the policies of insurance required herein shall be for the account of the Contractor.

PHASE 3 DEVELOPMENTS & INVESTMENTS, LLC
Grow It * Use It * Renew It
In Ohio: 7155 Five Mile Road, Cincinnati, OH 45230 In Michigan: 1510 62nd Street, Fennville, MI 49408
Phone 513-265-2758 * Fax 513-233-3395 * email: Normacnc5@aol.com

July 8, 2007

Ms. Julie Baldwin
Michigan Public Service Commission

Subject: COMMENTS ON DRAFT DOCUMENT, 30kW & LARGER INTERCONNECTION PROCEDURES

Dear Ms. Baldwin:

This provides our comments to the draft document circulated for discussion at the June 19, 2007 meeting of the 30kW & Larger Interconnection Procedures Workgroup. We support the draft with the following exceptions:

1. In order to provide simple and effective tracking of the timeframe under which an application and interconnection are completed, we recommend a one-page cover document with each of the steps in the process, and columns to fill in the date completed, and initials by the utility and the developer. The document would also contain the contacts for each party. Any issues which delay interconnection would also be noted on this single page, using supplemental documents for detailed information.

2. We recommend that information for Section 4 (types 1, 2, and 3 interconnection location decisions) be available at the pre-application meeting outlined in Section 1.1.

3. While we understand that the rate which developers will be paid for any power sold to the utility is currently outside the scope of the interconnection procedures discussion, we recommend that costs for interconnection be creditable against the first year's power sales by the developer.

Sincerely,

Norma S. McDonald
Operating Manager

AMERICAN TRANSMISSION COMPANY LLC
THE ENERGY ACCESS COMPANY

N19 W23993 RIDGEVIEW PARKWAY WEST ■ P.O. BOX 47 ■ WAUKESHA, WI 53187-0047
262-506-6700 ■ Toll Free: 866-899-3204 ■ Fax: 262-506-6710 ■ www.atcllc.com

BY ELECTRONIC MAIL

July 10, 2007

Ms. Julie Baldwin, and
Mr. Brian Mills
Michigan Public Service Commission
6545 Mercantile Way
Lansing, Michigan 48909

In re: Docket 15113 -30+ kW Interconnection Standards
Comments of American Transmission Company (ATC)

Dear Ms. Baldwin and Mr. Mills:

This letter responds to your invitation to comment on the draft "MPSC Staff Strawman Proposals for Improvements to Interconnection Procedures", which relates to interconnection standards for distribution-interconnected generators of 30 kW or greater and was discussed at the June 19, 2007 meeting of the Commission Staff. This letter addresses recommendation #3 in the Commission Staff's proposal.

ATC filed comments with the Commission on April 20, 2007 indicating the need for consultation between the distribution and transmission utilities and providing guidelines for when this consultation should occur. ATC also indicated that the transmission owner would need 10 to 15 days to determine and report if further study was necessary. We are pleased that the Commission Staff has considered our comments and incorporated some of our suggestions into the Commission Staff's proposal. ATC is pleased to provide the following additional comments on the generation to distribution interconnection process.

ATC re-iterates that in most cases where generation seeks to interconnect to distribution voltage facilities, ATC, as the transmission owner, can assess interconnection impacts on the transmission system concurrent with utility studies, and only in a few cases does ATC believe additional study time would be needed to evaluate the impact of the proposed interconnection on the transmission system.

Staff Recommendations and ATC comments

<u>Recommendation 3.1: Identify threshold of when the distribution utility must notify the transmission utility of a proposed generator interconnection to the distribution system.</u>

ATC is pleased that the Commission Staff has incorporated a modified version of the threshold test suggested in our previous comments. ATC agrees with the notion that the interconnection process should not be unnecessarily delayed by involvement of a transmission owner unless the specific circumstances of a particular interconnection warrant that involvement.

ATC requests that the Commission Staff consider two modifications to recommendation 3.1. In ATC's comments filed on April 20, 2007, ATC noted the following suggested threshold test:

> *The alternative threshold tests that ATC would recommend are: Where a single generator request or the aggregation of existing and new generation, measured at the transmission-to-distribution (T-D) point of interconnection, exceeds a) the minimum distribution load or, b) the total connected generation is 10 MVA or greater, transmission consultation should be required. (These are the two alternate tests.) In these cases some, but not most, interconnection requests will require detailed study.*

The current wording of recommendation 3.1 does not incorporate an evaluation by the distribution utility of whether or not the aggregation of existing distribution connected generation and the proposed generator interconnection exceed either of the two thresholds in the notification test. As previously noted, this aggregation would be measured at the transmission-to-distribution (T-D) point of interconnection. As such, the distribution utility, and not the interconnection customer, would need to make this evaluation. ATC believes this evaluation is important since generators operating in parallel on the electric grid have a cumulative effect on the electric network that must be taken into account in evaluating the impact of any new or increased generating capacity.

As noted above, ATC does not intend to burden the interconnection process with unnecessary process steps. Therefore, although the Commission Staff has proposed a 2 MW threshold as one part of their test, ATC believes that raising this threshold to a higher value, such as 10 MW, would serve both the interests of reliability and efficiency in the interconnection process. If the Commission Staff incorporates the suggestion that an aggregation of existing and proposed generation should be considered, then ATC strongly encourages the Commission Staff to raise the MW threshold test to avoid unnecessary evaluation by the transmission owner.

Recommendation 3.2: Transmission utility notification regarding participation in a study.

ATC agrees with the Commission Staff that the transmission owner should expeditiously review information supplied by the distribution utility and should expeditiously indicate if study of the potential transmission system impacts must be undertaken. ATC believes that ensuring timely review of an interconnection customer's application assures non-discriminatory treatment and also makes good business sense. ATC suggests that the Staff recommendation be modified to permit adequate flexibility in the study schedule when a particular interconnection request warrants it.

In recommendation 3.2, ATC believes that the Commission Staff proposal inadvertently introduces inflexibility into the interconnection process by requiring the transmission owner (and the Midwest Independent Transmission System Operator, Inc.) to conform to the distribution utility's study schedule. As ATC noted in its comments filed on April 20, 2007,

> *Simply put, most generator-to-distribution (G-D) interconnections will require no transmission system impact study and would likely also not require any transmission impact mitigation. Some interconnections to distribution facilities, however, may have material, adverse impacts on the reliable operation of the adjacent, interconnected transmission system and would "trigger" the need for some form of transmission system impact study.* [footnote omitted] *ATC would anticipate that such a study, in most cases, could be completed in 10 to 15 days, and could be done concurrent with the distribution company analysis of its system. A few interconnections, however, could require 90 or more days for impact and mitigation studies. Whether a more detailed analysis would*

be required, could likely be determined in the first 15 days following receipt of the necessary information concerning the generator and the proposed interconnection. With that determination, the transmission owner could also provide preliminary estimates of scope of the study, the cost of the study and time required to perform the detailed analysis.

ATC suggests that the Commission Staff include the following language to ensure flexibility for the transmission owner in those rare instances when a more detailed impact and mitigation study is required. In the strawman, after para. 3,2, add:

"<u>In the TO response to the distribution utility, the TO should provide a good faith estimate of the time required to perform a transmission impact study</u>."

This language will ensure, for example, that studies of large generator interconnections to the distribution utility are not inadvertently forced into a restricted study schedule that would not permit proper evaluation of system reliability and safety, or that developers are not misled into expecting a complete study and response when circumstances may require more time. It has been ATC's experience that developers seeking to interconnection large generators to the distribution network understand the need for longer, more detailed studies and ATC does not believe that this flexibility will result in inappropriate delays for an interconnection customer. An example of a large generator interconnection to a distribution utility can be found at the following web link:

http://oasis.midwestiso.org/documents/ATC/G225_Facility_Study_Report.pdf

<u>Recommendation 3.3: Transmission utility response requirements.</u>

ATC agrees with the Commission Staff's proposal that the transmission utility respond to the distribution utility within 10 business days as to whether or not the transmission utility will participate in system studies but believes that notification of receipt of a request within 3 business days by the transmission owner is an unnecessary process step. The Commission Staff could state that "the transmission owner should respond within 10 business days. If the transmission owner does not respond, the distribution utility may assume that no transmission impacts need to be considered." This approach will reduce the burden on the transmission owner to meet short deadlines that only confirm receipt of a request and allow the transmission owner to focus on evaluating whether or not a study of potential transmission system impacts is warranted.

Thank you for this opportunity to comment.

Sincerely,

/s/ Jay A. Porter

Jay A. Porter
Manager, Regional Planning
ATC Management Inc.
American Transmissions Company LLC
262-506-6931

Comparison of 10 kW and Under Interconnection Procedures for Inverter Based Generator Projects			
Phase	**Current Michigan Procedures (from under 30 kW set)** ***Xcel and I&M are not subject to these procedures.** **Staff recommendations found reasonable by the Commission in U-15113 Order dated 2/27/07**	**Wisconsin Procedures (Category 1: 20 kW or less)**	**Comments/Proposed Changes**
	Utility is required to appoint a single point of contact for interconnection matters.	Utility is required to appoint a single point of contact for interconnection matters. Each utility shall have current information concerning its point of contact on file with Commission. PSC 119.03	
	Utility must appoint a knowledgeable utility interconnection project manager.		
Application	Standard Statewide Application	Standard Statewide Application PSC 119.02(34)	
	Interconnection & Operating Agreement is **not** standardized across utilities.	Interconnection & Operating Agreement is standardized across utilities. PSC 119.02(35)	
	Application Fee $100	No Application Review Fee Table 119.08-1	
	1 page application with the following attachments: inverter-type generator application data sheet (2-pages and the following attachments: site plan, simple one-line diagram, detailed one-line diagram, written commissioning test procedure, NRTL certification)	3 page application form with the following attachments: one-line diagram, site plan, certificate of insurance, copy of proof of equipment certification. One-line schematic diagram, PSC 119.10 Site plan, PSC 119.12 Proof of certification, PSC 119.26 Insurance, PSC 119.05. See also Application Form and Interconnection Agreement.	
	Utility acknowledges receipt of application within 3 business days. This acknowledgement should be in writing.		

Comparison of 10 kW and Under Interconnection Procedures for Inverter Based Generator Projects			
Phase	**Current Michigan Procedures** **(from under 30 kW set)** ***Xcel and I&M are not subject to these procedures.** **Staff recommendations found reasonable by the Commission in U-15113 Order dated 2/27/07**	**Wisconsin Procedures** **(Category 1: 20 kW or less)**	**Comments/Proposed Changes**
	No time limit for utility completeness review. Utilities shall evaluate the application for completeness and notify the applicant in writing within 10 business days of receipt regarding the following: 1. Whether application is complete; and if not, advise what materials are missing. 2. Any changes in rates the utility believes will be required or optional (such as standby rates). 3. All remaining activities the applicant must conclude, for the application to be complete.	Utility shall notify applicant within 10 working days of receipt whether application is complete. PSC 119.04(3)	

Comparison of 10 kW and Under Interconnection Procedures for Inverter Based Generator Projects			
Phase	**Current Michigan Procedures (from under 30 kW set)** **Staff recommendations found reasonable by the Commission in U-15113 Order dated 2/27/07**	**Wisconsin Procedures (Category 1: 20 kW or less)**	**Comments/Proposed Changes**
Utility Review	Utility must complete its obligations within 2 weeks after the application is complete. Delays that are the responsibility of the project developer do not count toward the 2 week timeline.	Utility has 10 working days after application is deemed complete to finish its application review. The application review will determine if an engineering review is necessary. PSC 119.04(4)	
	All generators under 30 kW are processed under these procedures.	All generators 20 kW or less are processed under these procedures. PSC 119.02(4)	
	Interconnection Study Agreement Fee is the lesser of 5% of total project cost or $10,000. No charge if aggregate export capacity is less than 15% of the line section peak load and does not contribute more than 25% of the maximum short circuit current at the point of interconnection.	No Engineering Review or Distribution System Study Fees Table 119-08-1	
	Interconnection Study Timing – completed within the 2 weeks of the date the utility determined the application was complete.	Engineering Review must be completed within 10 working days. PSC 119.04(5a)	
	Distribution System Study Timing – completed within the 2 weeks of the date the utility determined the application was complete.	Distribution System Study Timing – must be completed within 10 working days. PSC 119.04 (7a) Applicant must pay for any distribution modification or upgrade costs. PSC 119.04(9)	

Comparison of 10 kW and Under Interconnection Procedures for Inverter Based Generator Projects			
Phase	**Current Michigan Procedures (from under 30 kW set)** **Staff recommendations found reasonable by the Commission in U-15113 Order dated 2/27/07**	**Wisconsin Procedures (Category 1: 20 kW or less)**	**Comments/Proposed Changes**
Inspection, Testing & Operation	Insurance is required in the Interconnection & Operating Agreement. Staff does not have copies of these documents.	Applicant must provide a Certificate of Insurance with the application. PSC 119.05 Category 1 must have $300,000 in liability insurance. Table 119.05-1	
	The customer must provide 5 business days written advance notice of when the project will be ready for inspection, testing, and approval. The utility reserves the right to inspect the project.	The utility may perform an anti-islanding test only. PSC 119.04(10.a.2) Applicant shall notify the utility in writing that the DG installation is complete and that it is available for testing at least 15 working days before applicant interconnects to distribution system. Utility may witness the applicant's test or perform their own test. PSC 119.04 (10.a.3)	
	Utility may charge customer for upgraded meter.	Meters may spin backwards in the Wisconsin net metering program. The typical customer meter is usually satisfactory. MPSC Staff is uncertain about charges for meters for those circumstances where a new meter is required.	
	Utility may charge for site inspection and test observation.	Utility may not charge customer for site inspection and test observation. PSC 119.04(10.a.2)	
	External disconnect switch may be required.	External disconnect switch may be required. PSC 119.20(3)	
	Inverters must operate at a unity power factor.	Must be operated at a power factor greater than 0.9. PSC 119.20(7a)	

Michigan Public Service Commission
September 12, 2007

U-15113 10 kW and Under Interconnection Procedures

Comments Received on the

Staff's August 2007 Proposal

10 kW and Under
Faster & Less Complex Interconnection Procedures
Staff Proposal for Discussion
August 2007

Please be reminded that the Staff report to the Commission on this workgroup is due September 30. Please review this document, and provide comments in writing to Staff by not later than midnight on September 7. **Please email comments to baldwinj2@michigan.gov**.

Our workgroup was asked to develop faster and less complex interconnection procedures for 10 kW and under interconnection projects. (This task is not limited to inverter-based projects.)

Staff is asking the workgroup to review **Wisconsin Chapter PSC 119 Rules for Interconnection Distributed Generation Facilities** and the **Wisconsin Distributed Generation Interconnection Guidelines** , and **Wisconsin Application and Interconnection Agreement** to assess their suitability to Michigan. To highlight similarities and differences between the current Michigan rules and the Wisconsin rules, Staff prepared a comparison document. This comparison document is provided in MS Word format to make it easier for the workgroup to provide comments within the document, if desired.

Staff proposes these additions to the Wisconsin Rules:

1. Provide for a pre-application meeting between utility and project developer.
2. Include a provision for the Commission to appoint expert(s) to provide technical expertise related to interconnection issues.

   This function would be similar to the provision in the Animal Contact Current Mitigation Rules or PA 30 Electric Transmission Line Certification Act. Excerpts from these MPSC Administrative Rules appear on the next page. In particular, this expert would provide assistance to the Commission, in the event there are any cost-related or technical issue complaints.
3. Require distribution utilities to consult with transmission owners for all generator projects >2 MW and when total generation on a distribution line will exceed 10 MW.

In comments, please address the following questions:

1. Will these Wisconsin rules provide faster and less complex interconnection procedures for Michigan interconnections for small inverter based systems?

2. Do you support the idea of using these rules as the basis for new Michigan rules? If not, please explain why and provide any alternative recommendations.

3. What modifications (if any) to these Wisconsin rules do you recommend? Do you agree with the proposed modifications Staff has listed?

4. Is it acceptable for Michigan rules to adopt the Wisconsin generator size categories, in particular the "20 kW and less" category?

Animal Contact Current Mitigation Rules

R 460.2704 Request for investigation.

Rule 4. (1) After completion of the procedures in R 460.2702 and R460.2703, a complainant or the utility may request, with notification to the other party, that the commission appoint at least 3 and up to 5 experts to investigate in the manner in R 460.2705. If the commission appoints at least 3 and up to 5 experts, those experts shall have the rights and responsibilities as described in that rule and shall issue their investigation report and conclusions to the commission, the complainant, and the utility.

(2) The funding mechanisms in R 460.2705 shall be used to defray the costs of the experts as determined by the commission.

History: 2007 MR 3, Eff. Feb. 6, 2007.

R 460.2705 Appointment of experts.

Rule 5. (1) If a complainant or the utility requests an investigation through the commission under R 460.2704 of these rules, then the commission may appoint at least 3 and up to 5 experts to investigate the complaint and report findings to the commission within the scope of these rules. The commission shall consider expert individuals based on, but not limited to, all of the following criteria:

(a) Expertise specific to the specie affected.

(b) Objectivity - individuals not directly impacted by the resolution.

(c) Neutral third-party.

(d) Training and expertise in primary distribution systems and certification in secondary wiring systems.

(2) The experts shall limit their conclusions and reports to the subject of the dispute and the facts and circumstances of the specific case for which they were appointed.

(3) Either party may request specific disciplines be represented on the expert team.

(4) The experts shall submit a report to the commission with the results and conclusions of their inquiry, which may suggest corrective measures for resolving the complaint. The reports of the experts shall be received in evidence and the experts shall be made available for cross-examination by the parties at any hearing. The experts shall report to the commission within 30 days of their employ. The commission may grant up to a 30-day extension.

(5) The reasonable expenses of experts, including a reasonable hourly fee or fee determined by the commission, shall be submitted to the commission for approval and, if approved, shall be funded under subrule (6) of this rule.

(6) The utility shall reimburse the experts appointed by the commission for the reasonable expenses incurred in the course of investigating the complaint.

History: 2007 MR 3, Eff. Feb. 6, 2007.

<u>PA 30 Electric Transmission Line Certification Act</u>

460.568 (3) The commission may assess certificate application fees from the electric utility, affiliated transmission company, or independent transmission company to cover the commission's administrative costs in processing the application and may require the electric utility, affiliated transmission company, or independent transmission company to hire consultants chosen by the commission to assist the commission in evaluating those issues the application raises.

Comparison of 10 kW and Under Interconnection Procedures for Inverter Based Generator Projects

Phase	Current Michigan Procedures (from under 30 kW set) *Xcel and I&M are not subject to these procedures. Staff recommendations found reasonable by the Commission in U-15113 Order dated 2/27/07	Wisconsin Procedures (Category 1: 20 kW or less)	Comments/Proposed Changes
	Utility is required to appoint a single point of contact for interconnection matters.	Utility is required to appoint a single point of contact for interconnection matters. Each utility shall have current information concerning its point of contact on file with Commission. PSC 119.03	
	Utility must appoint a knowledgeable utility interconnection project manager.		
Application	Standard Statewide Application	Standard Statewide Application PSC 119.02(34)	
	Interconnection & Operating Agreement is **not** standardized across utilities.	Interconnection & Operating Agreement is standardized across utilities. PSC 119.02(35)	*Standardization reduces confusion and delays.*
	Application Fee $100	No Application Review Fee Table 119.08-1	*This Wisconsin policy minimizes obstacles to application.*
	1 page application with the following attachments: inverter-type generator application data sheet (2-pages and the following attachments: site plan, simple one-line diagram, detailed one-line diagram, written commissioning test procedure, NRTL certification)	3 page application form with the following attachments: one-line diagram, site plan, certificate of insurance, copy of proof of equipment certification. One-line schematic diagram, PSC 119.10 Site plan, PSC 119.12 Proof of certification, PSC 119.26 Insurance, PSC 119.05. See also Application Form and Interconnection Agreement.	*The simplest form possible should be required. Our 2006 application with DTE, for interconnection of our 3.2 kW array, was so complex, that no one on our team (which included a solar contractor, an AP physics teacher, a medical doctor, and a graduate of UM engineering school) could figure out how to complete it. After weeks of frustration, we finally ended up copying nearly word for word the Ypsi Food co-op's application from a year prior, substituting our specs. Without the co-op's helps (and use of their application) we would have been lost.*

Comparison of 10 kW and Under Interconnection Procedures for Inverter Based Generator Projects

Phase	Current Michigan Procedures (from under 30 kW set) *Xcel and I&M are not subject to these procedures. Staff recommendations found reasonable by the Commission in U-15113 Order dated 2/27/07	Wisconsin Procedures (Category 1: 20 kW or less)	Comments/Proposed Changes
	Utility acknowledges receipt of application within 3 business days. This acknowledgement should be in writing.		
	No time limit for utility completeness review. Utilities shall evaluate the application for completeness and notify the applicant in writing within 10 business days of receipt regarding the following: 1. Whether application is complete; and if not, advise what materials are missing. 2. Any changes in rates the utility believes will be required or optional (such as standby rates). 3. All remaining activities the applicant must conclude, for the application to be complete.	Utility shall notify applicant within 10 working days of receipt whether application is complete. PSC 119.04(3)	*The faster and the more specific the information provided to the applicant, the faster the process can proceed. I believe Michigan's current rules are superior in this case.*

Comparison of 10 kW and Under Interconnection Procedures for Inverter Based Generator Projects

Phase	Current Michigan Procedures (from under 30 kW set) Staff recommendations found reasonable by the Commission in U-15113 Order dated 2/27/07	Wisconsin Procedures (Category 1: 20 kW or less)	Comments/Proposed Changes
Utility Review	Utility must complete its obligations within 2 weeks after the application is complete. Delays that are the responsibility of the project developer do not count toward the 2 week timeline.	Utility has 10 working days after application is deemed complete to finish its application review. The application review will determine if an engineering review is necessary. PSC 119.04(4)	*Faster timelines save the citizens of Michigan time, money and energy.*
	All generators under 30 kW are processed under these procedures.	All generators 20 kW or less are processed under these procedures. PSC 119.02(4)	***Encouraging Michigan businesses and residents to provide their energy renewably helps Michigan's economy and environment for years to come. The higher 30 kW limit will allow proportionally more renewable power production in this category of producers. I don't see how reducing the limit to 20 kW would help the citizens of Michigan, or how it would improve the environment economically or ecologically. I guess I'm not clear on why the change to 20 kW is being suggested.***
	Interconnection Study Agreement Fee is the lesser of 5% of total project cost or $10,000. No charge if aggregate export capacity is less than 15% of the line section peak load and does not contribute more than 25% of the maximum short circuit current at the point of interconnection.	No Engineering Review or Distribution System Study Fees Table 119-08-1	*Again, Wisconsin has fewer obstacles to getting distributed energy on the grid.*
	Interconnection Study Timing – completed within the 2 weeks of the date the utility determined the application was complete.	Engineering Review must be completed within 10 working days. PSC 119.04(5a)	*Wisconsin rules again provide faster timelines.*

	Distribution System Study Timing – completed within the 2 weeks of the date the utility determined the application was complete.	Distribution System Study Timing – must be completed within 10 working days. PSC 119.04 (7a) Applicant must pay for any distribution modification or upgrade costs. PSC 119.04(9)	

Comparison of 10 kW and Under Interconnection Procedures for Inverter Based Generator Projects			
Phase	**Current Michigan Procedures (from under 30 kW set)** **Staff recommendations found reasonable by the Commission in U-15113 Order dated 2/27/07**	**Wisconsin Procedures (Category 1: 20 kW or less)**	**Comments/Proposed Changes**
Inspection, Testing & Operation	Insurance is required in the Interconnection & Operating Agreement. Staff does not have copies of these documents.	Applicant must provide a Certificate of Insurance with the application. PSC 119.05 Category 1 must have $300,000 in liability insurance. Table 119.05-1	*My homeowners insurance, which also covers my PV array, meets this liability amount requirement. There is no indication in table 119.05 nor the related text to the contrary, so my assumption is that my PV array does not need it's "own" separate liability policy.*
	The customer must provide 5 business days written advance notice of when the project will be ready for inspection, testing, and approval. The utility reserves the right to inspect the project.	The utility may perform an anti-islanding test only. PSC 119.04(10.a.2) Applicant shall notify the utility in writing that the DG installation is complete and that it is available for testing at least 15 working days before applicant interconnects to distribution system. Utility may witness the applicant's test or perform their own test. PSC 119.04 (10.a.3)	*The five day requirement currently in place in Michigan will reduce the time to interconnect.*

	Utility may charge customer for upgraded meter.	Meters may spin backwards in the Wisconsin net metering program. The typical customer meter is usually satisfactory. MPSC Staff is uncertain about charges for meters for those circumstances where a new meter is required.	*Especially here the Wisconsin rules remove obstacles to placing non-polluting, locally harvested energy on the grid. My "typical" meter was working perfectly fine, until DTE forced me to replace it.* *This particular Wisconsin actual <u>net</u> metering policy truly encourages renewable energy generation. In contrast, the so-called "net metering" (but actually energy-portion-only) rule sought by Michigan utilities would greatly discourage grid-tied renewables by devaluing every kWh sent to the grid by nearly half.* *Grid-tied Solar systems provide peak energy production when the utilities need it most-when they currently have to buy energy from out of state--why would Michigan want to discourage its citizens from paying their own private money to make our grid more robust, more efficient, more environmentally sound and more impervious to terrorism? I wish that the Michigan utilities would stop giving lip service to "green currents," and instead be truly supportive of renewable energy by adopting this Wisconsin policy.*
	Utility may charge for site inspection and test observation.	Utility may not charge customer for site inspection and test observation. PSC 119.04(10.a.2)	*In all of these last points, Wisconsin removes even more disincentives to clean energy production. If Michigan wants to be ready for the economy of the 21st century, we need to lead, not lag behind our neighboring states.*
	External disconnect switch may be required.	External disconnect switch may be required. PSC 119.20(3)	

	Inverters must operate at a unity power factor.	Must be operated at a power factor greater than 0.9. PSC 119.20(7a)	*Allowing power factors in a reasonable range of values again allows more clean energy on the grid.* *In summary, I believe the Wisconsin procedures would generally create a faster and less complex inter-connection process.* *Any of Michigan's current procedures which are simpler or more encouraging of distributed, clean energy production, should be retained.* *The Staff Proposals for addition to the Wisconsin Rules seem generally agreeable to me, but I'm not clear if* "Provide for a pre-application meeting between utility and project developer" *means that such a meeting is required, or if it means that it will be available by request of the customer.* *Respectfully Submitted,* *Joshua Barclay* *4445 Valentine Rd* *Whitmore Lake, MI 48189* *JoshuaBarclay@earthlink.net*

Memorandum

To: Julie Baldwin, MPSC Staff

From: James A. Ault, Michigan Electric & Gas Association (on behalf of indicated electric utilities)

Date: September 7, 2007

Re: Joint Comments on Staff Proposal for Discussion – Interconnection Procedures

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I. Introduction

These joint comments are provided on behalf of the following electric utilities: Consumers Energy Company, The Detroit Edison Company, Alpena Power Company, Edison Sault Electric Company, Indiana Michigan Power Company, Upper Peninsula Power Company, We Energies, Wisconsin Public Service Corporation, Xcel Energy, and members of the Michigan Electric Cooperative Association. These comments address (i) Interconnection Procedures – 10kW and Under and (ii) Interconnection Procedures – 30kW and Larger, as identified in the Staff Proposals for Discussion of August, 2007. Unless otherwise stated, the comments below reflect the consensus views of the participating utilities. The specific questions posed in the Staff documents are repeated here to establish the framework for the joint comments.

II. Procedures – Projects ≤ 10 kW

Staff Q1: Will these Wisconsin rules provide faster and less complex interconnection procedures for Michigan interconnections for small inverter-based systems?

Response: Subject to more specific comments on the rules, set forth below, the answer to this question is that the WI rules will provide less complex procedures. The step-by-step approach used in WI would be helpful.

Staff Q2: Do you support the idea of using these rules as the basis for new Michigan rules? If not, please explain why and provide any alternative recommendations.

Response: Generally, "yes." There are a number of potential issues, including the need to consider whether the formal rules should incorporate matters now addressed in the interconnection procedures of each utility and other Michigan-specific issues and circumstances. A major improvement would be to adopt the Wisconsin interconnection application process and timeline, which uses separate and distinct "steps" instead of a single, overall deadline. Some utilities would not support complete adoption of the WI technical guidelines to replace the MI procedures, however. Once new rules are developed, the utilities could submit conforming requirements which address some of the detail needed beyond the formal rules, as occurred previously.

Staff Q3: **What modifications (if any) to these Wisconsin rules do you recommend? Do you agree with the proposed modifications Staff has listed?**

Response: (A) Recommended modifications include:

(i) Project Manager: this should be just one person, designated as the "point of contact". For the small projects, there is likely no need for a utility project manager provided an appropriate contact is identified.

(ii) Application Fee: removal of the $100 application fee would cause more subsidization of the project developers. The fee should continue.

(iii) Standard Application: MI is now using a 1-page form versus the 3-page WI form; the longer form may be more complex than necessary.

(iv) Standard Forms: Some utilities expressed a preference to continue using the MI forms for interconnection application and agreement with any necessary modifications. Also, several expressed preference for the MI generation data forms over the WI versions.

(v) Equipment Certification: UL 1741 certification changes over time because the standard is updated. The essential point here is that the certification incorporates the anti-islanding standard (2 seconds or less) of IEEE 1547. Certification via "UL 1741 in compliance with IEEE 1547" or similar language will address this concern. Older equipment brought into a project, certified under an earlier version of UL 1741, should meet the newer standard with anti-islanding requirements.

WI Rule 119.20(6)(b) should be replaced regarding the smaller projects(under 30 kW) to allow certification of the interconnection relaying system by a nationally recognized laboratory to meet IEEE 1547. Data submitted must include manufacturer's information indicating such certification and equipment should be placarded to allow field verification.

The list of approved relays and equipment should continue to be part of the MI requirements.

(vi) Insurance and Indemnity: Including an insurance certificate with the application form (WI rule) is preferred. Although the WI insurance provision and coverage levels are acceptable to some, we do not have agreement on the indemnity language in the WI rules and alternatives should be considered.

(vii) Time Deadlines: The rules should be very clear that the "clock starts" only after the application is accepted as complete by the utility. Further, the WI approach with sequential timelines and activities is more workable than the MI approach with a single timeline for completed interconnection.

(B) Comments on the three additions to the WI rules proposed by Staff are as follows:

(i) Pre-Application Meeting: For these small projects, the term "meeting" should include telephone conferences. A formal meeting will not be necessary for many projects (e.g. plug and play) and the scope of meeting/conference should be as needed for the project.

(ii) Expert Panel: This recommendation should not be adopted because it could lead to added expense and unnecessary demands by persons who will bear none of the investigation expense. An informal industry working group could be developed to provide technical information, on a voluntary basis.

(iii) Transmission Owner Consultation: This proposed addition is generally not applicable to small projects ($\leq$ 10kW) feeding the local distribution network.

Staff Q4: **Is it acceptable for Michigan rules to adopt the Wisconsin generator size categories, in particular the "20 kW and less" category?**

Response: The electric utilities are not in full agreement on this issue. The largest utilities, Detroit Edison and Consumers Energy, support continuation of the existing size categories (e.g. smallest is $\leq$30 kW). Utilities serving in both WI and MI (WE, WPS, Xcel) would favor consistency among the two jurisdictions, thus the WI categories. This consistency approach would include affiliated companies such as UPPCo and ESE in the Upper Peninsula. If changes are to be made in the categories, utilities request the opportunity to propose alternatives.

III. Procedures – Projects $\geq$30kW

Staff Q1: **Will these Wisconsin rules, with the proposed Michigan additions, satisfactorily resolve any of the issues the Commission has asked our workgroup to address? Which ones?**

Response: Yes, as to Commission issues #1, 4, and 6 identified in the Staff proposal, subject to additional comments on the following items:

(i) Power Factor: PSCW Rule 119.20(7) uses 0.9 power factor for projects up to 200 kW, and then "unity" or "as agreed" above that. If the MI categories are used, a demarcation would be appropriate at 150 kW and above. Projects in the 150-200 kW range would use a range of no less than .95 leading through .95 lagging with unity/agreement above that range..

(ii) Rule Revision: In MI there are very general formal rules, covering basic matters including timelines. Technical matters and details are left to the less formal interconnection procedures. If the "WI model" is adopted, we need to consider how to integrate with the formal rules and informal procedures in MI. It would be possible to preserve the MI structure while revising the rules and procedures.

(iii) Pre-Application Meeting: See earlier comment. A formal meeting should be optional depending on circumstances. Telephone consultation is a preferred method, with the formal meeting only if necessary. For the larger projects, there could be a provision for requesting a formal meeting.

(iv) Expert Panel: See earlier comment. Use of independent experts should be handled based on the unique circumstances of a particular contested matter, rather than being a more automatic procedure.

(v) Transmission Owner Consultation: See earlier comment. For the larger projects (>2 MW), the term "consult" may raise concerns because the utility is not proposing the project. The distribution utility would notify the transmission owner for any project that may impact the transmission system. However, the scope of any transmission study and the time needed are matters for the transmission owner and project developer to address.

Staff Q2: Do you support the idea of using the Wisconsin rules as the basis for new Michigan rules? If not, why not? And, if not, do you have an alternative recommendation for consideration?

Response: Generally, subject to addressing Michigan-specific issues and circumstances, utilities have supported the Wisconsin interconnection application approach as previously noted. Alternative recommendations are discussed above. Some utilities would not support complete adoption of the WI technical guidelines to replace the MI procedures, however, as also discussed above. For the projects in this size category, utilities should have the right to approve protective relays and equipment.

Staff Q3: What topics should be covered at the proposed pre-application meeting between a utility and a project developer or customer?

Response: This meeting should address the project overview and background facts, covering basic matters such as location, project description, area facilities, ability to accommodate, contact information and the interconnection requirements. As noted previously, a formal meeting should not be mandatory in all cases.

Michigan Public Service Commission
September 12, 2007

U-15113 30 kW and Larger Interconnection Procedures

Comments Received on the

Staff's August 2007 Proposal

30 kW and Larger Interconnection Procedures
Staff Proposal for Discussion
August 2007

Please be reminded that the Staff report to the Commission on this workgroup is due September 30. Please review this document, and provide comments in writing to Staff by not later than midnight on September 7. **Please email comments to baldwinj2@michigan.gov**.

These are the issues the Commission directed our workgroup to address:

1. Identify reasonable and achievable interconnection time deadlines.
2. Propose a system for determining whether interconnection costs are reasonable, actual costs.
3. Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications (for distribution-level interconnections) are filed.
4. Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.
5. Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system.

An additional interconnection issue identified by interested parties and Staff is:

6. Insurance requirements and liabilities.

Staff is asking the workgroup to review **Wisconsin Chapter PSC 119 Rules for Interconnection Distributed Generation Facilities** and the **Wisconsin Distributed Generation Interconnection Guidelines** to assess their suitability for possible application for Michigan.

Staff proposes these additions to the Wisconsin Rules:

1. Provide for a pre-application meeting between utility and project developer.
2. Include a provision for the Commission to appoint expert(s) to provide technical expertise related to interconnection issues.

   This function would be similar to the provision in the Animal Contact Current Mitigation Rules or PA 30 Electric Transmission Line Certification Act. Excerpts from these MPSC Administrative Rules appear on the next page. In particular, this expert would provide assistance to the Commission, in the event there are any cost-related or technical issue complaints.
3. Require distribution utilities to consult with transmission owners for all generator projects >2 MW and when total generation on a distribution line will exceed 10 MW.

In comments, please address the following questions:

1. Will these Wisconsin rules, with the proposed Michigan additions, satisfactorily resolve any of the issues the Commission has asked our workgroup to address? Which ones?

2. Do you support the idea of using the Wisconsin rules as the basis for new Michigan rules? If not, why not? And, if not, do you have an alternative recommendation for consideration?

3. What topics should be covered at the proposed pre-application meeting between a utility and a project developer or customer?

<u>Animal Contact Current Mitigation Rules</u>

R 460.2704 Request for investigation.

Rule 4. (1) After completion of the procedures in R 460.2702 and R460.2703, a complainant or the utility may request, with notification to the other party, that the commission appoint at least 3 and up to 5 experts to investigate in the manner in R 460.2705. If the commission appoints at least 3 and up to 5 experts, those experts shall have the rights and responsibilities as described in that rule and shall issue their investigation report and conclusions to the commission, the complainant, and the utility.

(2) The funding mechanisms in R 460.2705 shall be used to defray the costs of the experts as determined by the commission.

History: 2007 MR 3, Eff. Feb. 6, 2007.

R 460.2705 Appointment of experts.

Rule 5. (1) If a complainant or the utility requests an investigation through the commission under R 460.2704 of these rules, then the commission may appoint at least 3 and up to 5 experts to investigate the complaint and report findings to the commission within the scope of these rules. The commission shall consider expert individuals based on, but not limited to, all of the following criteria:

(a) Expertise specific to the specie affected.

(b) Objectivity - individuals not directly impacted by the resolution.

(c) Neutral third-party.

(d) Training and expertise in primary distribution systems and certification in secondary wiring systems.

(2) The experts shall limit their conclusions and reports to the subject of the dispute and the facts and circumstances of the specific case for which they were appointed.

(3) Either party may request specific disciplines be represented on the expert team.

(4) The experts shall submit a report to the commission with the results and conclusions of their inquiry, which may suggest corrective measures for resolving the complaint. The reports of the experts shall be received in evidence and the experts shall be made available for cross-examination by the parties at any hearing. The experts shall report to the commission within 30 days of their employ. The commission may grant up to a 30-day extension.

(5) The reasonable expenses of experts, including a reasonable hourly fee or fee determined by the commission, shall be submitted to the commission for approval and, if approved, shall be funded under subrule (6) of this rule. (6) The utility shall reimburse the experts appointed by the commission for the reasonable expenses incurred in the course of investigating the complaint.

History: 2007 MR 3, Eff. Feb. 6, 2007.

<u>PA 30 Electric Transmission Line Certification Act</u>

460.568 (3) The commission may assess certificate application fees from the electric utility, affiliated transmission company, or independent transmission company to cover the commission's administrative costs in processing the application and may require the electric utility, affiliated transmission company, or independent transmission company to hire consultants chosen by the commission to assist the commission in evaluating those issues the application raises.

Baldwin, Julie K (DLEG)

From: Stanton, Thomas S (DLEG)
Sent: Friday, August 24, 2007 9:08 AM
To: 'normacnc5@aol.com'
Cc: Baldwin, Julie K (DLEG)
Subject: RE: MPSC Staff Discussion Paper on Interconnection Procedures

-----Original Message-----
From: normacnc5@aol.com [mailto:normacnc5@aol.com]
Sent: Thursday, August 23, 2007 6:48 PM
To: Stanton, Thomas S (DLEG)
Subject: Re: MPSC Staff Discussion Paper on Interconnection Procedures

Tom,

We have reviewed the Wisconsin rules and the suggested Michigan amendments and it is our opinion that these rules and procedures represent an improvement over the existing Michigan rules and utility guidelines. The Wisconsin rules and forms are clearer and simpler to complete. The timeframes, while longer in some cases, are specific and appropriately scaled to differently sized-projects.

The two remaining questions we have are:

1. What determines whether or not a full engineering study and distribution study is required? What triggers this?
2. Since construction timing must be mutually agreed upon, will the appointed MPSC interconnection expert be the one who helps resolve differences in timing expectations? Or will a formal complaint be the only means to resolve issues?

Norma S. McDonald
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Memorandum

To: Julie Baldwin, MPSC Staff

From: James A. Ault, Michigan Electric & Gas Association (on behalf of indicated electric utilities)

Date: September 7, 2007

Re: Joint Comments on Staff Proposal for Discussion – Interconnection Procedures

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I. Introduction

These joint comments are provided on behalf of the following electric utilities: Consumers Energy Company, The Detroit Edison Company, Alpena Power Company, Edison Sault Electric Company, Indiana Michigan Power Company, Upper Peninsula Power Company, We Energies, Wisconsin Public Service Corporation, Xcel Energy, and members of the Michigan Electric Cooperative Association. These comments address (i) Interconnection Procedures – 10kW and Under and (ii) Interconnection Procedures – 30kW and Larger, as identified in the Staff Proposals for Discussion of August, 2007. Unless otherwise stated, the comments below reflect the consensus views of the participating utilities. The specific questions posed in the Staff documents are repeated here to establish the framework for the joint comments.

II. Procedures – Projects ≤ 10 kW

Staff Q1: Will these Wisconsin rules provide faster and less complex interconnection procedures for Michigan interconnections for small inverter-based systems?

Response: Subject to more specific comments on the rules, set forth below, the answer to this question is that the WI rules will provide less complex procedures. The step-by-step approach used in WI would be helpful.

Staff Q2: Do you support the idea of using these rules as the basis for new Michigan rules? If not, please explain why and provide any alternative recommendations.

Response: Generally, "yes." There are a number of potential issues, including the need to consider whether the formal rules should incorporate matters now addressed in the interconnection procedures of each utility and other Michigan-specific issues and circumstances. A major improvement would be to adopt the Wisconsin interconnection application process and timeline, which uses separate and distinct "steps" instead of a single, overall deadline. Some utilities would not support complete adoption of the WI technical guidelines to replace the MI procedures, however. Once new rules are developed, the utilities could submit conforming requirements which address some of the detail needed beyond the formal rules, as occurred previously.

Staff Q3: What modifications (if any) to these Wisconsin rules do you recommend? Do you agree with the proposed modifications Staff has listed?

Response: (A) Recommended modifications include:

(i) Project Manager: this should be just one person, designated as the "point of contact". For the small projects, there is likely no need for a utility project manager provided an appropriate contact is identified.

(ii) Application Fee: removal of the $100 application fee would cause more subsidization of the project developers. The fee should continue.

(iii) Standard Application: MI is now using a 1-page form versus the 3-page WI form; the longer form may be more complex than necessary.

(iv) Standard Forms: Some utilities expressed a preference to continue using the MI forms for interconnection application and agreement with any necessary modifications. Also, several expressed preference for the MI generation data forms over the WI versions.

(v) Equipment Certification: UL 1741 certification changes over time because the standard is updated. The essential point here is that the certification incorporates the anti-islanding standard (2 seconds or less) of IEEE 1547. Certification via "UL 1741 in compliance with IEEE 1547" or similar language will address this concern. Older equipment brought into a project, certified under an earlier version of UL 1741, should meet the newer standard with anti-islanding requirements.

WI Rule 119.20(6)(b) should be replaced regarding the smaller projects(under 30 kW) to allow certification of the interconnection relaying system by a nationally recognized laboratory to meet IEEE 1547. Data submitted must include manufacturer's information indicating such certification and equipment should be placarded to allow field verification.

The list of approved relays and equipment should continue to be part of the MI requirements.

(vi) Insurance and Indemnity: Including an insurance certificate with the application form (WI rule) is preferred. Although the WI insurance provision and coverage levels are acceptable to some, we do not have agreement on the indemnity language in the WI rules and alternatives should be considered.

(vii) Time Deadlines: The rules should be very clear that the "clock starts" only after the application is accepted as complete by the utility. Further, the WI approach with sequential timelines and activities is more workable than the MI approach with a single timeline for completed interconnection.

(B) Comments on the three additions to the WI rules proposed by Staff are as follows:

(i) Pre-Application Meeting: For these small projects, the term "meeting" should include telephone conferences. A formal meeting will not be necessary for many projects (e.g. plug and play) and the scope of meeting/conference should be as needed for the project.

(ii) Expert Panel: This recommendation should not be adopted because it could lead to added expense and unnecessary demands by persons who will bear none of the investigation expense. An informal industry working group could be developed to provide technical information, on a voluntary basis.

(iii) Transmission Owner Consultation: This proposed addition is generally not applicable to small projects ($\leq$ 10kW) feeding the local distribution network.

Staff Q4: Is it acceptable for Michigan rules to adopt the Wisconsin generator size categories, in particular the "20 kW and less" category?

Response: The electric utilities are not in full agreement on this issue. The largest utilities, Detroit Edison and Consumers Energy, support continuation of the existing size categories (e.g. smallest is $\leq$30 kW). Utilities serving in both WI and MI (WE, WPS, Xcel) would favor consistency among the two jurisdictions, thus the WI categories. This consistency approach would include affiliated companies such as UPPCo and ESE in the Upper Peninsula. If changes are to be made in the categories, utilities request the opportunity to propose alternatives.

III. Procedures – Projects $\geq$30kW

Staff Q1: Will these Wisconsin rules, with the proposed Michigan additions, satisfactorily resolve any of the issues the Commission has asked our workgroup to address? Which ones?

Response: Yes, as to Commission issues #1, 4, and 6 identified in the Staff proposal, subject to additional comments on the following items:

(i) Power Factor: PSCW Rule 119.20(7) uses 0.9 power factor for projects up to 200 kW, and then "unity" or "as agreed" above that. If the MI categories are used, a demarcation would be appropriate at 150 kW and above. Projects in the 150-200 kW range would use a range of no less than .95 leading through .95 lagging with unity/agreement above that range..

(ii) Rule Revision: In MI there are very general formal rules, covering basic matters including timelines. Technical matters and details are left to the less formal interconnection procedures. If the “WI model” is adopted, we need to consider how to integrate with the formal rules and informal procedures in MI. It would be possible to preserve the MI structure while revising the rules and procedures.

(iii) Pre-Application Meeting: See earlier comment. A formal meeting should be optional depending on circumstances. Telephone consultation is a preferred method, with the formal meeting only if necessary. For the larger projects, there could be a provision for requesting a formal meeting.

(iv) Expert Panel: See earlier comment. Use of independent experts should be handled based on the unique circumstances of a particular contested matter, rather than being a more automatic procedure.

(v) Transmission Owner Consultation: See earlier comment. For the larger projects (>2 MW), the term “consult” may raise concerns because the utility is not proposing the project. The distribution utility would notify the transmission owner for any project that may impact the transmission system. However, the scope of any transmission study and the time needed are matters for the transmission owner and project developer to address.

Staff Q2: Do you support the idea of using the Wisconsin rules as the basis for new Michigan rules? If not, why not? And, if not, do you have an alternative recommendation for consideration?

Response: Generally, subject to addressing Michigan-specific issues and circumstances, utilities have supported the Wisconsin interconnection application approach as previously noted. Alternative recommendations are discussed above. Some utilities would not support complete adoption of the WI technical guidelines to replace the MI procedures, however, as also discussed above. For the projects in this size category, utilities should have the right to approve protective relays and equipment.

Staff Q3: What topics should be covered at the proposed pre-application meeting between a utility and a project developer or customer?

Response: This meeting should address the project overview and background facts, covering basic matters such as location, project description, area facilities, ability to accommodate, contact information and the interconnection requirements. As noted previously, a formal meeting should not be mandatory in all cases.