Wisconsin
Small Distributed Renewable Energy System
Interconnection Rules and Processes
Survey Results

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For
Grow Solar Wisconsin Team
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Thank you: Survey Respondents

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Table of Contents

Executive Summary

Top ten best practices that respondents agreed on[1]:

1. Interconnection Charges/Fees: no charges/fees for net metering systems, 84%
2. Distribution System Upgrades: clarify rules, 83%
3. Communications Links: use least cost option, 83%
4. Interconnection Testing Process: develop uniform statewide process 80%
5. Individual System Capacity: increase maximum size to 20 MW, 80%
6. Fast Track Approval Process: review and improve current process, 76%
7. Insurance, Additional Insured: remove utility as additional insured, 75%
8. Dispute Resolution: make similar to FERC process, 74%
9. System Size Breakpoints: change category 1 breakpoint to 100 kW, 72%
10. System Capacity Rating Definition: change to inverter's nameplate rating, 72%

Introduction

This Wisconsin Interconnection Survey is the Grow Solar Wisconsin (GSW) Team's first step in the process of modifying Wisconsin's interconnection rules and processes for distributed renewable energy generation systems. The survey results will be used to help determine the distributed generation sector's initial positions.

A subcommittee of the Wisconsin Distributed Resources Collaborative (WIDRC) will be formed to update Wisconsin's interconnection rules. The findings of this survey will be used to inform the WIDRC subcommittee. The GSW Team will participate in the subcommittee and interested survey respondents will be invited to participate.

The issues identified, and best practices noted, in this survey, are primarily based on the recommendations of a 2011 report, Wisconsin Net Metering and Interconnection Analysis, completed by Keyes and Fox, LLP for the National Renewable Energy Laboratory and Milwaukee Shines. The GSW Team, based on their experiences in Wisconsin, added four questions.

Modifications to Wisconsin's interconnection rules and processes supported by WIDRC and a group of stakeholders will either be:

- Included in a binding agreement, developed with WIDRC utility members, or
- Recommended as modifications to PSC 119, presented to the Public Service Commission of Wisconsin (PSCW), and legislators, who are expected to formally introduce the changes to the State Legislature.

[1] Results were corrected for "no opinion" responses.

The binding agreement will only include items that do not require legislative changes (i.e., are not included in PSC 119 or other regulations). Items that could be included in a binding agreement are:

- Definition of capacity rating (survey item 3)
- External disconnect switch requirement (survey item 8)
- Certification (survey item 9)
- Standard form agreements (survey item 11)
- Standardized interconnection testing process (survey item 14)
- Communications links for distributed generation systems (survey item 16)

Summary of Findings

Survey Distribution and Response Rate

The survey was distributed twice by email to stakeholder groups. Stakeholder groups include:

- Wisconsin Solar Email List
- Wisconsin Small Wind Email List
- Bioenergy Email List
- WIDRC member Email List
- Solar Installers
- MREA's Training Network

Recipients had over two weeks to respond. A total of 18 individuals responded. It is estimated that 200 to 300 individuals, with an interest in interconnection, participate in these email lists. The survey's overall response rate was under 10%. Given that there are about 50 active solar electric system installers in Wisconsin, the response rate for solar electric system installers was about 20%.

The profession of the respondents are:

- Ten solar electric system installers (two also install small wind systems)
- Two solar electric system component manufacturer staff
- Two solar electric system educators
- Two renewable energy consultants
- One solar electric system developer
- One electric utility representative

The GSW team expected responses from biogas engineering firms and developers, as interconnection changes will affect all distributed renewable generation. The low utility response rate is surprising, but utility representatives will actively participate in the discussions at WIDRC.

Respondent Participation

Eight respondents indicated an interest in participating in the WIDRC interconnection revision discussions, including: four solar electric system installers, a manufacturer, a utility representative, and a solar electric project developer. All eight will be invited to participate.

Summary of Survey Responses[2]

Top Ten Areas of Greatest Agreement, with the share of respondents who agreed with the recommended best practice:

1. Interconnection Charges and Fees (question 6): 84%
2. Distribution System Upgrades (question 15): 83%
3. Communications Links (question 16): 83%
4. Standardized Interconnection Testing Process (question 14): 80%
5. Individual System Capacity (question 1): 80%
6. Fast Track Approval Process (question 5): 76%
7. Insurance, Additional Insured (question 12.2): 75%
8. Dispute Resolution (question 13): 74%
9. System Size Breakpoints (question 2): 72%
10. System Capacity Rating Definition (question 3.1): 72%

Areas of Greatest Disagreement, with the share of respondents who disagreed with the recommended best practice:

1. System Size Breakpoints (question 2): 17%
2. Dispute Resolution (question 13): 16%
3. Application Process and Timeline (question 4): 11%
4. External Disconnect Switch (question 8): 11%
5. Certification (of non UL equipment) (question 9): 11%

All other areas had less than 10% of respondents disagreeing with the recommended best practice.

Areas with Greatest Need for Discussion, with the share of respondents who felt further discussion was needed:

1. Insurance, Maximum Liability for Large Systems (question 12.3): 64%
2. Engineering Review and Study Charges (question 7): 42%
3. Insurance, Small Systems (question 12.1): 37%
4. Application Process and Timeline (question 4): 33%
5. Standard Agreement Form (question 11): 32%
6. Network Interconnections (question 10): 29%
7. Fast Track Approval Process (question 5): 24%
8. Certification (of non UL equipment) (question 9): 24%

[2] Results were corrected for "no opinion" responses.

9. Standard Interconnection Testing Process (question 15): 20%
10. Insurance, Utility as Additional Insured (question 12.2): 19%

Survey Questions and Responses

1. Individual System Capacity

Current Wisconsin Status:
PSC 119 rules cover systems of 0 to 15 MW

Best Practice:
Option 1 - Increase maximum size to 20 MW (for non-FERC jurisdictional systems)
Option 2 - Remove the size cap, and have the rules cover all state jurisdictional systems

Survey Results

Responses	Number	Share
Agree Option 1	6	30%
Agree Option 2	10	50%
Needs Further Discussion	3	15%
Disagree	1	5%
No Opinion		

Respondent's comments

1. Would prefer a 1 MW net metering limit

2. Systems at the larger end of the scale require additional utility involvement. It will be important that if the cap is removed the rules will not unduly impact smaller systems as a result of utilities attempting to mitigate the larger system impacts on their plant.

2. System Size Breakpoints for the Interconnection Process

Current Wisconsin Status:
Cat. 1: greater than 0 to 20 kW
Cat. 2: greater than 20 to 200 kW
Cat. 3: greater than 200 kW to 1 MW
Cat. 4: greater than 1 MW to 15 MW

Best Practice:
Cat. 1: greater than 0 to 100 kW
Cat. 2: greater than 100 to 200 kW

Cat. 3: greater than 200 kW to 1 MW
Cat. 4: greater than 1 MW to 20 MW or when FERC takes jurisdiction

Survey Results

Responses	Number	Share
Agree	13	72%
Needs Further Discussion	2	11%
Disagree	3	17%
No Opinion		

Respondent's Comments

1. Cat 4 to 20 MW, concerned 100 kW cap will increase fees

2. 200 kW arbitrary break point. Typically sites over 100 kW utilize central inverters, and central inverters are standardized at 250 kW and 500 kW with few exceptions. I propose that 250 kW would be a more sensible break between Cat 2 and Cat 3.

3. Raising the Cat. 1 top end makes sense from an installer and consumer standpoint, however, there are likely technical issues such as ratings of utility transformers and other equipment that may dictate logical breakpoints. If after these issues are considered, it may make sense to have category 1 be for up to 20kW residential systems, and up to 100kW for non-residential systems, or some other qualifier (transformer capacity serving site), and still have a total of 4 categories. Perhaps the 2 mid-categories are not useful and the sizes can be re-allocated based on value in doing so.

3. Definition of Capacity Rating

(Not identified in the Freeing the Grid report)

Current Wisconsin Status:
PSC 119 does not provide a clear definition (I could not find it). The PSCW's "Standard Distributed Generation Application Form" is also unclear. Some utilities consider it the system's peak annual power production.

Best Practice:
Provide a clear definition, and ensure that the same definition is used in both interconnection and net metering rules and documents.

Option 1: Capacity rating in the inverter's nameplate AC rating, or if there is no inverter, the generator's AC rating

Option 2: Capacity rating is based on the generator's AC rating for systems without invertors, or DC nameplate rating for systems with inverters.

Survey Results

Responses	Number	Share
Agree Option 1	13	72%
Agree Option 2	4	22%
Needs Further Discussion		
Disagree	1	6%
No Opinion		

Respondent's Comments

1. What ComEd Il uses, works OK

2. DC rating has a much clearer linkage to expected production, in my experience. AC rating, if used for capacity, should carry a given DC/AC overload or it is too subjective.

3. Seems like the AC capacity is really what should be of interest to the grid

4. I believe capacity is and should be the projected annual power produced by the system, regardless of generation type. For PV, the NREL PV Watts number may be a good standard. Inverter nameplate rating suffers from the likelihood that an inverter sized larger than its source may be used. This has the potential to push a system's rating artificially higher with possible impacts on Question 2 above and possible incentive limits.

4. Application Review Process and Timelines

Current Wisconsin Status:
As outlined in PSC 119.

Discussion:
The Freeing the Grid report recommends using FERC technical screens and time lines. The comparison of the WI and FERC processes, from the Wisconsin Net Metering and Interconnection Analysis, is shown below. It is not clear that using the FERC technical screens and timeline in Wisconsin would be an improvement. The FERC process is more complex, and timelines tend to be longer. However, there are technical issues in the Wisconsin application review process that are not clear-cut, and therefore allow utility discretion. It may be preferable to have more exact requirements.

Interconnection Process and Timelines based on FERC Small Generator Rules and PSC 119 (Source: Wisconsin Net Metering and Interconnection Analysis completed by Keyes and Fox, LLP, 2011).

Application Step	FERC Business Days	Current WI Business Days
Notice of complete application	10	10
Fast-track initial review	15	10
Customer options meeting	10 from FT screen failure	
Supplemental review	10 from receipt of deposit	
Feasibility study agreement	5 from scoping meeting	
Feasibility Study Report (engineering)	30 from execution and delivery of agreement	Cat. 1: 10 days Cat. 2: 15 days Cat. 3: 20 days Cat. 4: 40 days After receipt of payment and agreement
System Impact Study Agreement	15 from transmittal of Feasibility Study Report	
System Impact Report (distribution system study)	30 days from execution and payment of agreement	Cat. 1: 10 days Cat. 2: 15 days Cat. 3: 20 days Cat. 4: 40 days After receipt of payment and agreement
Facilities Study Agreement	5 days from completion of System Impact Study	
Facilities study report (distribution system study)	No Upgrade: 30 days Upgrade required: 45 days	Cat. 1: 10 days Cat. 2: 15 days Cat. 3: 20 days Cat. 4: 40 days After receipt of payment and agreement
Interconnection Agreement delivered	5 days from completion of Facilities Study	

<u>Survey Question</u>
Review the FERC interconnection application review standards, process and timeline, and update the Wisconsin process and timeline.

Survey Results

Responses	Number	Share
Agree	8	44%
Needs Further Discussion	6	33%
Disagree	2	11%
No Opinion	2	11%

Respondent's Comments

1. OK to review and discuss pros and cons of each provision

2. Must avoid adding complexity without a valuable benefit. Some tasks are in need of major improvement, starting with feedback that the utility has received the application and that it is complete. We are at 10 days, as is FERC. Any business entity, including a utility, should be able to do this in hours, not days, at least for simple systems, such as those under current Category 1 requirements. The application should be automated and on-line, including for whatever levels of approval are needed at the utility.

5. Fast-Track Approval Process

Current Wisconsin Status:
Systems of less than 20 kW can have their application for interconnection approved within 10 business days.

Survey Question:
Review the FERC fast-track process to update the Wisconsin's interconnection application process for small systems, creating a Wisconsin fast-track approval process.

Survey Results

Responses	Number	Share	Share Excluding No Opinion
Agree	13	68%	76%
Needs Further Discussion	4	21%	24%
Disagree			
No Opinion	2	11%	

Respondent's Comments

1. 10 days seems pretty fast for approval

2. 10 biz days is reasonable, changing Cat 1 to fast track may complicate the fast track

3. Again, this response time needs to be much quicker. Automating the review process will help facilitate this. Approval of simple applications should be in 1 or 2 days at most from receipt of complete application.

6. Interconnection Charge/Fees

Current Wisconsin Status:
No application fee or charge for systems with a capacity of 20 kW and less

Best Practice: No fee for 100 kW and less (new WI net metering limit)

Survey Results

Responses	Number	Share
Agree	16	84%
Needs Further Discussion	3	16%
Disagree		
No Opinion		

Respondent's Comments

1. I'd like to hear why a fee needs to be changed going from 20 to 100 kW. The limit is 5 x's larger and there may be reasons for a charge.

2. Large break between 20 and 100 kW, more than with other category breaks

3. Need for fee should be based on need for extra work on the part of the utility, due to such things as the system's AC rating being greater then utility transformer and related equipment, and thus requiring further analysis. It hopefully can be a quick check to determine the need for such an analysis, and only charge when extra work is required. As noted, there should be no charge for simple systems as this is or becomes defined, as having a cost adds work and time to the process for both the customer and utility, and so doesn't provide value for simple systems.

7. Engineering Review and Study Charges

Current Wisconsin Status:

Category	Application Fee	Engineering Review Fee	Distribution System Study Fee
1	0	0	0
2	$250	Max $500	Max $500
3	$500	Cost based	Cost based
4	$1000	Cost based	Cost based

Best Practice:
Provide maximum allowable fee for cost-based fees

Survey Results

Responses	Number	Share	Share Excluding No Opinion
Agree	6	32%	50%
Needs Further Discussion	5	26%	42%
Disagree	1	5%	8%
No Opinion	7	37%	

Respondent’s Recommended Fees

Category	Engineering Review Fee	Distribution System Study Fee
3	% job cost cost based (2) $1000 (2)	% job cost cost based (2) $1000 (2)
4	% job cost cost based (2) $2000 $1500	% job cost cost based (2) $2000 $1500

Respondent’s Comments

1. I do not know what the limiting factors are on this topic; is it dictated by municipalities and their overhead structure?

2. Grid application fees as costs should be minimal if system is automated and on-line. Past range and average of fees by category would be useful for planning purposes, but it seems that setting a fee for the evaluation is going to set a figure that is likely never going to be right, and will only be close if ever, at the time it is set. There are many variables, so setting cost doesn't seem reasonable, unless this would simplify things for the utility.

8. External Disconnect Switch

Current Wisconsin Status:
The utility may require a disconnect switch. (Additionally, One utility requires that the external AC disconnect switch is within 5 feet of the meter.)

Best Practice:
Option 1: For all systems with a UL/IEEE approved inverter, the external disconnect is prohibited.
Option 2: For systems of under __ kW (10 kW to 100 kW) with a UL/IEEE approved inverter, the external disconnect is prohibited.

<u>Survey Results</u>

Responses	Number	Share	Share Excluding No Opinion
Agree Option 1	9	47%	50%
Agree Option 2	5	26%	28%
Needs Further Discussion	2	11%	11%
Disagree	2	11%	11%
No Opinion	1	5%	

Respondent's Comments

1. This switch, in most cases, is redundant and only adds cost. In many cases, especially commercial applications it is difficult and expensive to provide for this disconnect. I think that a DC disconnect should also be an option.

2. I assume what is meant is that the requirement is prohibited? There are clearly situations that necessitate an external disconnect, such as when the POI is located a significant distance from the array

3. Number 1 makes sense but I would like to hear from utilities and electricians why they think there needs to be a redundant switch

4. It should not be "prohibited", the option for the utility to require this should simply be removed. Or could word some other way that allows an outside disconnect only if the customer or system owner wants one.

5. Alliant Energy use to require the disconnect within 5 feet. They now require no disconnect. I had a discussion with the Alliant Engineer for my area and he described a situation where multiple homes were fed from one transformer and there were benefits during utility maintenance for having a disconnect in this situation.

6. I think it is best for an external disconnect that provides workers with a visual open. It is needed to ensure the safety of our workers. Inverters can fail at any time.

7. The "need" for this switch has never made sense to me. On a residential system the switch adds hundreds of dollars to the system installation cost (material and labor) and is often a source of aesthetic concern for the purchaser.

9. Certification

Current Wisconsin Status:
Interconnection standards utilize UL 1741/IEEE 1547.

Best Practice: Address the issue of self-certified systems. Allow the reuse of certification on equipment and configurations already individually type-tested by a utility, rather than having to recertify an already utility-tested component or configuration.

Survey Results

Responses	Number	Share
Agree	13	68%
Needs Further Discussion	4	21%
Disagree	2	11%
No Opinion		

Respondent's Comments

1. Seems reasonable unless I'm missing something

2. Need discussion to better understand what this means with some examples.

3. It is best to complete a system test anytime a component is changed out to ensure the system functions as designed. There could be compatibility issues between different suppliers equipment.

4. This seems so obvious that it begs the question of why we don't already have this as a standard.

10.Network Interconnection

Current Wisconsin Status:

PSC 119.20(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.”

Best Practice:

1. Both spot and area network interconnections are allowable based on flexible criteria and the customer’s load characteristics.
2. Network interconnections are allowed, as long as the generating facility is inverter-based and uses additional non-exporting protective schemes.
3. Networks interconnections are allowed with single/minimal protective schemes.

Survey Results

Responses	Number	Share	Share Excluding No Opinion
Agree Option 1	3	18%	21%
Agree Option 2	7	41%	50%
Agree Option 3			
Needs Further Discussion	4	24%	29%
Disagree			
No Opinion	3	18%	

Comments

- Need more info to better understand this.

11. Standard Form Agreement

Current Wisconsin Status:
Two standardized forms, which are lacking some clauses.

Discussion:
Example clauses from FERC small generator agreement
Force Majeure Clause

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

> "If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible."

<u>Assignment Clause</u>
From FERC small generator interconnection agreement (page 11):
Change Assignment Language

> "This Agreement may be assigned by either Party upon 15 Business Days prior written notice and opportunity to object by the other Party; provided that:
>
> "Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the Transmission Provider of any such assignment;
>
> "The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Transmission Provider, for collateral security purposes to aid in providing financing for the Small Generating Facility, provided that the Interconnection Customer will promptly notify the Transmission Provider of any such assignment.
>
> "Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed."

Best Practice:
Add the Force Majeure, Assignment and other clauses as needed.

Survey Results

Responses	Number	Share	Share Excluding No Opinion
Agree	13	62%	68%
Needs Further Discussion	6	29%	32%
Disagree			
No Opinion	2	10%	

Respondent's Comments

- Although this language does add clarity in some rare circumstances, I don't think all this language should be in the form. Instead, the definitions should be referenced in the form
- Too much legal talk for me to comment on
- I trust this has been vetted by both utility and RE advocates. I'd be interested in hearing discussion if it does come up.

12. Insurance Requirements

Current Wisconsin Status:

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

Discussion:
From FERC small generator interconnection agreement (page 14):
"The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility.

Best Practice:

1. Remove additional insurance requirements for non-inverter-based systems of under 50 kW and inverter-based systems of under 100 kW.

Survey Results

Responses	Number	Share	Share Excluding No Opinion
Agree	12	57%	63%
Needs Further Discussion	7	33%	37%
Disagree			
No Opinion	2	10%	

Respondent's Comments

1. Some form of insurance is needed, but not sure why utility's require it in the interconnection agreement

2. Insurance is necessary in most cases there are still people who are not sufficiently responsible. But amounts can be onerous.

3. Remove liability insurance requirements all together unless specific risk events and probabilities can be identified and evaluated to determine the appropriateness of requiring insurance and at what level for what systems. The insurance requirement adds time and potential costs and delays even for simple systems currently.

4. I'd like to see examples from the insurance industry of claims relevant to liabilities from solar generating equipment or from the interconnection of private and utility generating equipment. If none can be obtained, what is the argument for the liability coverage above 50 and/or 100 kW?

Best Practice:

2. Remove requirement for utility being listed as additional insured.

Survey Results

Responses	Number	Share	Share Excluding No Opinion
Agree	12	71%	75%
Needs Further Discussion	3	18%	19%
Disagree	1	6%	6%
No Opinion	1	6%	

Respondent's Comments

1. Need to revisit some reasons these provisions are in the WI edition

2. Since the insurance requirement is intended to protect both parties it seems reasonable that both parties should be named. What good cause exists to not name the utility?

Best Practice:

3. Provide a maximum liability insurance requirement for category 4 systems.

Survey Results

Maximum insurance level: $2,000,000 (2 individuals)

Responses	Number	Share	Share Excluding No Opinion
Agree	3	17%	27%
Needs Further Discussion	7	39%	64%
Disagree	1	6%	9%
No Opinion	7	39%	

Respondent's Comments

1. I view this as one of many negotiation points between the purchaser / financier and the utility. I'd hate to see us take something off the "menu" of negotiable options.

2. Again, I have not had to deal with insurance for systems of this size and am not in a position to decide the maximum insurance level.

13. Dispute Resolution

Current Wisconsin Status:
Right to Appeal from PSC 119.40:

"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."

Discussion:
From FERC small generator interconnection agreement, Article 10:Disputes:
"The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

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

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

“The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the Internet at http://www.ferc.gov/legal/adr.asp.

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

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

Best Practice:
Update PSC 119 language to provide more detail (similar to the FERC process) regarding timelines, staff review process, etc.

Survey Results

Responses	Number	Share
Agree	14	74%
Needs Further Discussion	2	11%
Disagree	3	16%
No Opinion		

Respondent’s Comments

1. Some updating may be needed, especially if there is evidence that the current PSC process is not working

2. All stakeholders must be involved in determining the details.

3. General comment I'd have is the amount of revisions suggested seem to be growing to a size that could create an insurmountable amount of resistance if the state legislature is not politically motivated to take this up.

14. Standardized Interconnection Testing Process

(Not identified in the Freeing the Grid report)

Current Wisconsin Status:
Utilities have different processes regarding who attends, if testing occurs, time window for tests, when the system can be interconnected, etc.

Best Practice: Develop simple process that is uniform across all utilities.

Survey Results

Responses	Number	Share
Agree	16	80%
Needs Further Discussion	4	20%
Disagree		
No Opinion		

Respondent's Comments

1. A standardized process in the state needs to be worked out

2. Will likely be some differing requirements by system size or category.

3. At least for utilities in the western part of the state, the utility rep throws the switch and makes sure the inverter shuts off as long as the equipment is UL listed. Do we need to encourage them to do more?

4. The key word here is "simple".

5. I agree, but I also would make the comment that some utilities and/or municipalities may have more robust requirements for this process, and while it may be argued that this serves the best interest of the utility and/or the customer, it may also impede a smooth and cost-effective transition to project commission without just cause for such delays.

15. Electric Distribution System Upgrades

(Not identified in the Freeing the Grid report)

Current Wisconsin Status:
A decision was made when PSC 119 (Rules for Interconnecting Distributed Generation Facilities) was written to not include issues relating to electric line extensions and distribution system upgrades. This decision was made because rules for line extensions already existed in PSC 112 (Construction by Electric Public Utilities and Extensions of Electric Service) and PSC 113 (Service Rules for Electrical Utilities). Sometime after PSC 119 went into effect, the decision not to include line extension issues has caused

confusion and has made it difficult to complete projects. This issue most affects Category 3 and Category 4 distributed generators.

Best Practice:
Clarify the rules about distribution system upgrades specific to distributed generation, and include them in PSC 119. This will reduce potential uncertainty about the technical requirements for substation upgrades, regulators, breakers, recloser coordination issues, etc.

<u>Survey Results</u>

Responses	Number	Share	Share Excluding No Opinion
Agree	15	79%	83%
Needs Further Discussion	3	16%	17%
Disagree			
No Opinion	1	5%	

Respondent's Comments

1. Rather than repeat details from other PSC documents, may be better if requirements of other PSC documents are highlighted and reference to the controlling PSC documents is made clear. This way, changes made to the details regarding these topics will not cause the set of documents to get out of sync with each other.

16. Communication Links for Distributed Generation Systems

(Not identified in the Freeing the Grid report)

Current Wisconsin Status:
Telemetry, as it pertains to distributed generation (DG), means transmission of DG operating data using communication techniques. According to PSC 119, the public utility may require telemetry equipment with monitoring functions that include transfer−trip functionality, voltage, current, real power (watts), reactive power (vars), and breaker status for a Category 3 or Category 4 DG facility. The communication links may include a dedicated telephone line, satellite link, T1 line and fiber-optic cable.
These communication link types vary greatly in cost. Specifying an expensive communications link type can be cost prohibitive for small DG facilities.

Best Practice:
Change PSC 119 to require the least-cost communication link type for DG projects, unless the utility can demonstrate engineering necessity.

Results

Responses	Number	Share
Agree	15	83%
Needs Further Discussion	3	17%
Disagree		
No Opinion		

Respondent's Comments

1. This has been a barrier in some DG projects and needs to be defined and fixed

2. Least cost that meets the need. The needs perhaps need to be defined and included in an updated PSC119.

3. Change PSC 119 to require the utility to bear or share the cost. For smaller DG, there is no advantage to the purchaser. Therefore a comm. link only benefits the utility and is a burden (read tax) on the purchaser. Suggest that PSC 119 does NOT require comm. links for Cat. 1 systems and provides for a sliding scale of cost to be borne by the utility as the system sizes move upwards through the category rankings with the utility bearing all the cost in Cat. 4.

4. Yes, absolutely agree.

17. Respondent's Additional Interconnection Issues

What interconnection issues are important to you but were not included in this survey?

Respondent's Comments

1. Uniformity is very important to us

2. One location to send interconnection paperwork at the PSCW or have each utility identify (simply) one contact and reply with acceptance within a reasonable period of time (2 - 3 days). Have this listing on the PSCW website. An online form for PSC paperwork would also be preferred.

3. Probably off-topic, but important to me would be combining best practices for interconnection and for local permitting (mediated more with municipalities than with utilities) to really streamline the adoption of RE projects. For instance, why is it necessary to have a PE sign off on projects that have no chance of structural failure or do not have a precedent for requiring such an over-engineered solution for roof-based systems? Extending this requirement statewide without reasonable

exemptions would increase delays and real costs instead of "streamlining" RE project approval processes. I am concerned that spending $100's of thousands of dollars on this Sun Shot project will result in very impressive and robust regulatory solutions to real and imagined problems in the status quo, but that these solutions may increase the regulatory (read paperwork) burden for developers and utilities in accommodating projects that may in the future require additional legal counsel to review documents and procedures for smaller solar developers. National solar developers may be able to subsume these costs, but local or even statewide developers may need to pass these costs (including the cost of having to scrap a project due to delays) on to the consumer. This is just a concern, not a belief. If this entire revamping process creates a standardized form and set of understandings between stakeholders, and actually reduces the amount of paperwork as well as the time and expense on a per project basis, then it should be worth the taxpayer money spent.