

**Report of the  
Interconnection Standards Workgroup  
July 13, 2012**

Report to:

The Washington Utilities and Transportation Commission

The Washington Public Utility Districts Association

The Association of Washington Cities

The Washington Rural Electric Cooperative Association

Washington State Department of Commerce

and to:

The Washington State House Technology, Energy and Commerce Committee

The Washington State Senate Energy, Natural Resources and Marine Waters

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## **Introduction**

On March 11, 2010, the Washington Legislature passed E2SHB 2658 [Gov. signed on 4/1/2010 and became effective on 7/1/2010], tasking the Washington State Department of Commerce with updating the State Energy Strategy by December 1, 2011. During the legislative interim of 2011, the House Technology, Energy and Communications Committee initiated the Legislative Focus Group on Distributed Energy, chaired by Representative Deb Eddy, which reviewed the various efforts around distributed energy (DE) in the state. In response to a request from legislators, the Washington Utilities and Transportation Commission (UTC) published a report titled: Report on the Potential for Cost-Effective Distributed Generation In Areas Served by Investor-Owned Utilities in Washington State. Subsequently, on December 14, 2011 the UTC initiated a rulemaking (Docket UE112133), and on December 23, 2012 published a notice of opportunity to file written comments, to amend the interconnection rules (WAC 480-108) for generating facilities up to 20 Megawatts (MWs). Simultaneously, various consumer-owned utilities, in discussions with Rep. Eddy prior to the 2012 legislative session, had also agreed to review their interconnection standards, adopted by the majority of consumer-owned utilities in the state in 2006.

On January 30, 2012, The Washington Public Utility Districts Association (WPUDA), the Washington Rural Electric Cooperative Association (WRECA) and the Association of Washington Cities (AWC) as the Joint Publics Trade Associations, filed comments in the Commission proceeding. The comments suggested establishing a workgroup and process, outside of the Commission process but that would include all parties to the Commission proceeding plus consumer-owned utilities and any other parties that wished to participate. The process would be similar to a process undertaken in 2005 and 2006 that led to both the UTC and COUs adopting the current interconnection rules. The Workgroup would report their results to the UTC and three trade associations of COUs.

On March 29, 2012, a UTC workshop was held to discuss specific rule requirements and stakeholder input regarding the process and schedule for the course of the rulemaking. As a result of that workshop, the Commission agreed with the suggestion to develop a collaborative process (The Interconnections Standards Workgroup) and an agreed-up timetable was established. The Interconnection Standards Workgroup committed to provide a progress report by May 31, 2012, and to present final recommendations to the Commission and trade associations by June 30, 2012.

On June 25, 2012, an email on behalf of the Interconnections Standards Workgroup was submitted to the Commission and Joint Publics Trade Associations requesting an additional two weeks to deliver a final report and recommendation.

## **Process**

The Interconnection Standards Workgroup (Workgroup) held the first of four meetings on April 19, 2012. The Workgroup participants agreed to concentrate their discussion was focused on three main topics:

1. The requirement for an external, visible, lockable AC disconnect switch for all interconnected facilities;
2. The permissive authority for utilities to require insurance for non-net metered facilities, (net metered facilities are exempted from extra insurance requirements by RCW 80.60.040); and
3. Options for streamlining the application process.

The Workgroup informally appointed four co-chairs: Dave Warren, Director of Energy Services for the Washington Public Utility Districts Association (WPUA) , Tom DeBoer, Director of Federal and State Regulatory Affairs of Puget Sound Energy (PSE), Richard Damiano, Chief Engineer of Inland Power and Light Company (Inland), and Jason Keyes, attorney with Keyes, Fox and Wiedman LLP, representing the Interstate Renewable Energy Council, Inc. (IREC). In addition, the Workgroup commissioned a technical committee chaired by Richard Damiano, to specifically review the technology and need for an AC disconnect switch. All committees and email exchanges were open to any party that desired to participate.

The next three meetings were held on May 21, 2012, June 20, 2012 and July 2, 2012, with a final conference call on July 13, 2012. On June 30, 2012 the Workgroup requested a two week extension, from June 30, 2012 to July 13, 2012.

The Workgroup, after discussion, determined to provide specific recommendations by amending the model rule that the 05/06 Workgroup originally prepared, rather than attempt to edit two documents, both the UTC rule WAC 480-108 and the Model Rule that many of the COUs adopted. Our specific recommendations are attached as a model rule. Following is a description of the issues identified by the Workgroup.

## **Issues**

### External Disconnect

This issue generated the most discussion with agreement being difficult to reach. The current rules require a visible, lockable AC disconnect switch to provide a visible open point between all known energy sources and the electrical system on which a utility worker will be operating. This visible break of all phases is required by WAC (296-45-335 (16)) safety rules for de-energizing lines and equipment for employee protection.

Washington is not a “hot line” work state for facilities operated at over 4 kV, so while workers on low-voltage (<600 V) electrical systems may rely on circuit breakers for electrical isolation, the possibility of the DE system backfeeding into the primary distribution system mandates the disconnection of the equipment in order to ensure the safety of utility personnel working on the system, other customers in the isolated area, and the reliability of the system.

IREC argued that inverter technology has advanced sufficiently to shut down distributed generation using approved inverters, in order to prevent “islanding”<sup>1</sup> in the instance of distribution system de-energization. In addition, having the disconnect switch available to utility personnel added substantial costs in certain instances where the generation facility was not located sufficiently close to the property boundary and the disconnect switch had to be wired to the property boundary. IREC argued that while the cost of the disconnect switch runs from \$250 - \$400, this cost to the Interconnection Customer, coupled with the possible costs of wiring to the property boundary was redundant and unnecessary. IREC also argued that utility personnel could disconnect the facility at the meter base or transformer in a rare instance when the inverter failed. IREC provided two reports funded by the U’S. Department of Energy concluding that disconnect switches are unnecessary for smaller, inverter-based systems, and noted that the switch is not required and has not been installed on more than 100,000 systems in the U.S.<sup>2</sup>

Utilities argued that the cost of the disconnect switch is minor compared to the cost of the total DE system, protects the safety of its personnel and system, and allows workers to fully comply with existing safety requirements. WPUA and others argued that there is insufficient data on longer term performance of these inverters, and unless and until there was sufficient performance data, protecting personnel safety and system reliability is a higher priority. PacifiCorp and other utilities also argued that other influences, including state laws and policies had far more impact on any decision to build or not build distributed generation. In addition, the utilities argued that using a meter or transformer for disconnection is a purpose for which the equipment was not designed, and would cause longer outages and for potentially more customers than using a disconnect switch.

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<sup>1</sup> Islanding is the circumstance whereby an interconnected generating facility continues to generate electricity into the distribution system even when the electric utility’s distribution system is “down” due to storms, maintenance outages, or other events requiring the system to be “de-energized.”

<sup>2</sup> 1) Coddington, M.H., R.M. Margolis, and J. Aabakken (2008) *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*. National Renewable Energy Laboratory. Technical Report: NREL/TP-581-42675. Available at: [www.nrel.gov/docs/fy08osti/42675.pdf](http://www.nrel.gov/docs/fy08osti/42675.pdf), and 2) Sheehan, Michael T., P.E., *Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement*, published by Solar America Board for Codes and Standards. Available at: <http://www.solarbcs.org/about/publications/reports/ued/index.html>. For state procedures waiving the disconnect switch requirement for small, inverter-based systems, see scores of 0.5 or more in the “External Disconnect” column in the table of state interconnection procedures on pp. 88-89, “*Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures*, 2011 edition. Available at: [www.newenergychoices.org/uploads/FreeingTheGrid2011.pdf](http://www.newenergychoices.org/uploads/FreeingTheGrid2011.pdf). California’s three major utilities waive the requirement and alone have more than 100,000 net metered systems installed.

Avista, Snohomish PUD, IBEW and WPUA, among others, originally opposed providing a blanket waiver for external disconnects for inverter based generating facilities.

IBEW argued that worker safety rules requires the visible break disconnect which is not provided by an inverter possibly putting workers in violation of rules and in danger. They further pointed out that as these types of generating facilities are deployed in greater numbers, utilities should develop a locational dataset for the facilities and utility personnel will need additional training on hazard identification.

Eventually, some parties agreed, (IBEW and some utilities continue to oppose removing the requirement, while IREC still supports removing the requirement in all cases of inverter based facilities) to recommend language in the Model Rule allowing a utility to waive the requirement for a disconnect switch for inverter based facilities 5 kW or smaller; provided that the interconnection customer agreed to potentially longer outages without liability to the utility, alerted and obtained agreement from other customers regarding the longer outages, and provided regular testing of the inverter be performed in accordance with manufacturer's guidelines. In the absence of regular testing by the Interconnection Customer, the utility could disconnect and/or require installation of a disconnect switch for the generating facility.

However all parties agreed that as the vehicle fleet is electrified and deployed, and distributed energy technology comes of age, we will have to further research and address protection systems as we see widespread deployment of small generation sources throughout the distribution system.

### Insurance Requirements

Current Washington law prohibits a utility from requiring any additional liability insurance be obtained by net metered customers. Both UTC and COU rules state that a utility "may" require additional insurance for non-net metered generation facilities interconnected to the utility's system. IREC and WALEA argued that insurance was very expensive and it was hard to find carriers that were familiar with the risks, or lack thereof, with distributed generation - and thus premiums were inordinately high and in some cases cost prohibitive.

The only solution to the insurance issue would entail prohibiting a utility from requiring insurance for any facility, or for specific sizes or types of generating facilities. Because this option was unacceptable to the utilities, other options were explored. When IREC indicated that it was not trying to shift the cost of insurance to the utility, but wanted to explore ways to reduce the costs, the Workgroup requested Washington State Department of Commerce to explore options with the Office of the Insurance Commissioner, while

several utilities and utility trade associations explored options with their insurance carriers.

Utility insurance carriers gave a clear “no” to adding any DE facilities to the utility insurance policies without the utility having clear control of the facility, liability and control must be tied together for the utility insurance carriers to provide coverage. The Office of the Insurance Commissioner was helpful in working with Commerce and the result was communication with the Surplus Line Association of Washington that includes 600 surplus line brokers, and an offer from that Association to assist. The Surplus Line carriers often deal with unique or new situations. Over time surplus line coverage often evolves into being offered as standard coverage. Bob Hope of the Association is willing to assist in pulling together a meeting to discuss insuring independent power producers. He believes that the discussion should involve:

- Utility risk managers
- Utility insurance brokers
- Independent power producers
- Installers
- Equipment manufacturers
- Building owners
- Surplus lines insurers

Furthermore, he believes it will be necessary to clearly define the risks needing to be covered:

- Equipment
- Liability
- Utility system
- Operations
- Deep pocket
- New technology

The Interconnection Standards Workgroup encourages those parties that are interested to initiate this discussion, but is beyond the scope of our charge. The recommended model rule does not make changes to the current rule language that leaves the decision to require additional liability insurance to each utility.

#### Streamlining the Application Process

Current UTC and COU interconnection rules contain a table with various sizes and types of facilities linked with certain requirements that generally categorize facilities, with caveats contained in multiple footnotes below the table. The Technical Committee reviewed the table and came to the conclusion that the footnotes created more confusion

than clarity. Accordingly, the Workgroup did determine that our application process could use streamlining, benefitting both the utility and applicant by providing greater efficiency and clarity to the application review and approval process. We reviewed several states that IREC proposed as potential models to follow. The Workgroup chose Oregon's model as a starting point for our recommended streamlined process.

The recommended process in this Model Rule consists of three Tiers that a proposed project could fit into and the utility would utilize for review and approval. Tier 1 and Tier 2 contain applicability screens, both in text and flow charts<sup>3</sup>, process timelines, technical requirements and the completion process. Tier 3 includes the same screens timelines and processes, and also contains a list of studies that may be required depending upon characteristics and location of the generation facility being proposed.

**Tier 1** is for simple inverter-based single phase generation facilities of 25 kW or less, connected through a single phase transformer at secondary voltages (600 V class) and certain other characteristics. The complete application process, through approval or disapproval, will take about 35 business days or less, provided the submitted application is complete. The applicant has one year after approval of the application to interconnect and begin operation of the facility or the application expires. The requirement for a visible, lockable AC disconnect switch is waived at the utility's option for inverter-based facilities of 5 kW or less, provided they are interconnected through a self-contained socket based meter of 320 amps or less, the interconnection customer agrees to allow the utility to disconnect the facility through other means, and further agrees to test and maintain the inverter in accordance with the manufacturer's guidelines<sup>4</sup>, and in the absence of such documentation, agrees that the utility may disconnect the facility and require replacing the inverter and further may require the installation of a disconnect switch.

**Tier 2** is for generation facilities that do not meet Tier 1 criteria, have a nameplate rating of 500 kW or less<sup>5</sup>, is proposed for interconnection to a distribution system in the 38 kV (or less) Class, would require only minor upgrades, if any, to the distribution system, and has other limits on the impact and loading of the distribution system at the point of interconnection. The application process, through approval or disapproval, will take about 55 business days or less, provided the submitted application is complete. Once the application has been approved, the applicant has one year to begin operation of the facility or the application expires. A disconnect switch is required in all cases for Tier 2 projects.

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<sup>3</sup> See Appendix 1 of Model Rule for Process Flow Charts.

<sup>4</sup> And maintain documentation for utility inspection of such testing

<sup>5</sup> There was vigorous discussion about the cutoff for Tier 2, whether it should remain at 300 kW as it is in current rule, or increase to 500 kW. The group came to a decision that *most* machines in the 300 – 500 kW range would not pass the Tier 2 screen and thus the increase to 500 kW did not affect safety or reliability, but would allow inverter based systems in this size category to follow the streamlined Tier 2 process.

**Tier 3** is for all other projects up to 20 MW proposing to interconnect to a utility's distribution system. The Tier 3 application process is still under final review by the Workgroup<sup>6</sup>. An application is complete when all information that the utility requires to approve the application has been submitted by the applicant. The utility then identifies the studies that will be required to provide the information the utility and applicant will need to determine technical requirements for interconnection.

Once the applicant has agreed to the studies and made provisions for payment, the utility completes the studies on a timeline consistent with other service requests. The utility shall offer an Interconnection Agreement (IA) to the applicant, negotiate any changes if appropriate, the applicant and utility execute the IA.. The applicant then has two years from the date of approval of the IA to begin operation of the facility, or the application and IA expire.

### **Other Issues identified by the Workgroup**

#### Direct Transfer Trip

WALEA requested a discussion at our first meeting on the requirement for including a direct transfer trips at certain generating facilities. The Workgroup did discuss the technical complexities requiring a transfer trip at our second meeting, but did not fully vet or decide the issue, then did not take the issue up further. WALEA submitted language from the California Rule for inclusion in the Model Rule in the last few days before our deadline. Our Workgroup reviewed the language on our conference call on the last day and decided to include it in the Model Rule for further consideration. Although there is not a blanket exemption for inverter-based generating facilities, utilities should bear in mind that a direct transfer trip costs in the range of \$250,000 should not be unreasonably required for inverter based facilities. There may be, however, unusual circumstances where an inverter based facility in combination with a non-inverter based facility that a direct transfer trip or other similar protective device may be required for an inverter based facility.

#### Bonneville Power Administration

Snohomish PUD notes that utilities located within the balancing authority area (BAA) of a separate entity, such as Bonneville Power Administration (BPA), must deal with an

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<sup>6</sup> See Application through Commercial Operation in Tier 3 under "Other Issues" at the end of this report for further explanation



added layer of complexity with interconnection of small generators. For example, generators one (1) megawatt or larger that wish to interconnect to the distribution system of a utility located within BPA's BAA are subject to BPA's Small Generator Interconnection requirements, application process, and contractual agreements addressing required ancillary services and charges. In addition, generators 200 kW or larger may be subject to certain requirements by the BAA, such as metering and/or reporting of generation characteristics. Snohomish PUD further notes that it can take longer than a year to complete required efforts including performing BPA studies, executing construction and other agreements, and complying with metering requirements. As a result, the interconnection standards will need to be modified when a utility (such as Snohomish PUD) is not its own balancing authority area. At a minimum, Snohomish recommends that BPA be invited to participate in future discussions and comment on how the draft standards might be modified to accommodate their interconnection requirements.

### Tier 3 - Application and Completion Processes

The Tier 3 Application, Approval and Completion Processes and Technical Requirements are necessarily different from Tiers 1 and 2 due to the unique and more complex characteristics of these generating facilities and associated interconnection requirements. Because of the project complexities involved, the Tier 3 application process and timelines are still under review by the Workgroup. Neither the applicant nor the utility should expect streamlining or certainty in the timelines associated with these processes, but both should expect to apply due diligence and good faith in arriving at project approval.

The problem arises when an application that has been approved as complete had new information added (for instance, from the results of the studies), at that point the clock was reset and it becomes a completely new application. We are working on a process description and *suggested* timelines where the applicant does not have the clock reset on their application if the results of studies demonstrate that information in the application should change.

We are discussing a process where the applicant submits their application and the utility determines that the project will be a Tier 3 project. At that point the clock resets for both parties, and then the utility either determines that it requires more, or has sufficient information to deem an application complete. Once the application is deemed complete, the utility ideally reaches agreement with the applicant to conduct a low-cost feasibility study to determine what further studies are necessary and the costs of those studies. Once those further studies are completed, the results may require negotiation with the applicant and changing information in the application prior to executing an Interconnection Agreement. All parties agree that this potential modification of the application should not reset the clock on or be the cause for termination of the application, but is an area where

due diligence, due process and practical considerations for both parties should be taken into account.

### Chapter 8 - Adoption by Reference

The Workgroup seek guidance on inserting dates for codes, standards and publications that are adopted by reference. At least one code that the Workgroup is aware (IEEE 519) is currently under review and set for update soon, while certainly others will be updated between the date of adoption of this rule and the next review and update of this rule. WE are not certain if a rule can adopt by reference a code that has not yet been written, or whether “the most recent” will refer to the most recent version in effect on the date of adoption of this rule.

## **Attachment 1 - Glossary/List of Interconnection Standards Workgroup Participants**

Avista – Avista Utilities, Inc

Cascade Power

Commerce – Washington State Department of Commerce

IBEW – International Brotherhood of Electrical Workers

Inland Power and Light Company

IREC – Interstate Renewable Energy Council, Inc.

Mason County Public Utility District #3

PacifiCorp

Pend Oreille County Public Utility District

PSE – Puget Sound Energy

Seattle City Light

Snohomish County Public Utility District #1

Tacoma Public Utilities/ Tacoma Power

USDOE – United States Department of Energy

UTC – Washington Utilities and Transportation Commission

WALEA – Washington Local Energy Alliance

WPUDA – Washington Public Utility Districts Association

WRECA – Washington Rural Electric Cooperative Association