ITEM NO. RM2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: September 29, 2026

REGULAR __ CONSENT __ RULEMAKING _X_ EFFECTIVE DATE __N/A__

DATE: September 15, 2026

TO: Public Utility Commission

FROM: Ted Drennan and Aboubakr Abdallah

THROUGH: Caroline Moore, Scott Gibbens, and Curtis Dlouhy **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. AR 688)
Request to Move AR 688 Interconnection Rules to Formal Rulemaking.

STAFF RECOMMENDATION:

Staff recommends that the Oregon Public Utility Commission (Commission) approve Staff's request to open a formal rulemaking and issue a notice of proposed rulemaking to adopt changes to Division 82 Small Generator Interconnection Rules. The proposed draft rule revisions are included in Attachment 1.

Staff also recommends the Commission direct PGE, PacifiCorp, and Idaho Power to include in their interconnection requirements handbooks by the annual handbook update in 2027:

1. A detailed description of the approach they will use in identifying Direct Transfer Trip (DTT) in small generator interconnection studies, consistent with the criteria in Attachment 2-1.
2. An option for the net metering customer to install a single disconnect switch for all systems behind one meter under the conditions proposed by Staff in Attachment 3.

DISCUSSION:

Issue

Whether the Commission should initiate a formal rulemaking to adopt rules to make permanent provisions included in temporary rules adopted in AR 683 in response to

Executive Order 25-29, and to address remaining issues from Phase 2 of the UM 2111 investigation.

Applicable Rule or Law

Oregon Revised Statute (ORS) 756.060 provides "[t]he Public Utility Commission may adopt and amend reasonable and proper rules and regulations relative to all statutes administered by the commission and may adopt and publish reasonable and proper rules to govern proceedings and to regulate the mode and manner of all investigations and hearings of public utilities and telecommunications utilities and other parties before the commission."

Under ORS 757.035(1) the “Public Utility Commission has power … to adopt and prescribe the installation, use, maintenance and operation of appropriate safety or other devices, or appliances, to establish or adopt standards of construction or equipment, and to require the performance of any other act which seems to the commission necessary or proper for the protection of the health or safety of all employees, customers or the public.”

Existing administrative rules for small generator interconnections allow a generator to hire a third-party consultant to complete interconnection studies with the utility’s agreement (860-082-0060(9)). Oregon House Bill (HB) 2065 (2025) requires investor-owned electric utilities to provide microgrids the option to contract with a third-party consultant to conduct necessary interconnection studies or engineering evaluations and provides specific procedural and substantive requirements for third-party study for microgrids.

Executive Order 25-25 (EO 25-25) “Accelerating Wind and Solar Energy Development in Advance of Elimination of Federal Clean Energy Tax Credits” issued on October 6, 2025, directs the Public Utility Commission and other agencies to accelerate development of solar and wind energy projects in Oregon that seek to qualify for federal clean energy tax credits. This requires construction to commence by July 4, 2026, and imposes a four-year deadline for projects to be placed in service.

Executive Order 25-29 (EO 25-29) also encourages the Commission to find opportunities to use its scope and authority to accelerate clean energy procurement.

In 2009, the Commission adopted OAR Division 82 of Chapter 860 Small Generator Interconnection Rules (OR-SGIP) which outline the interconnection requirements for Oregon-jurisdictional generators up to 10 MW in size.[1]

[1] Commission Order No. 09-196.

Analysis

Background
The Commission opened Docket No. UM 2111 on July 6, 2020, to address a range of interconnection issues arising across generator types (i.e., net metering, small generator, large generator, community solar project). Given the breadth of issues, Staff conducted an open scoping process that resulted in a phased approach to addressing the issues list.[2] Phase 2 of the investigation began in 2025 and is focused on interconnection timelines and reducing delays. Through additional scoping and discussions of issues on the scope of rules and policy recommendations developed includes the following:

- Timeline expectations
  - Study timelines
  - Construction timelines
- Remedies when expectations are not met
  - Financial consequences for timeline violations
    - Offsets or surcharges to applicant costs
  - Options to build, as in the FERC LGIP
- Other readily available opportunities to mitigate interconnection delays
  - Utility/Applicant communication
  - Utility/Applicant meeting
  - Site visit requirements
  - Clarity on DTT upgrades
  - Interconnection timeline reporting requirements

On October 6, 2025, the Oregon Governor issued Executive Orders 25-25 and 25-29 related to accelerating timelines for clean energy development. EO 25-25 provided specific direction for Staff to propose interconnection policies.[3] .

Therefore, the Commission opened a temporary rulemaking (AR 683) and Staff and stakeholders shifted focus to an expedited rulemaking process focused on extending the opportunity for HB 2065 third-party studies to wind and solar and bringing forward a subset of the Phase 2 issues that would be most effective in accelerating interconnection timelines. The Commission adopted the temporary rules on April 1, 2026.[4]

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[2] Docket No. UM 2111, Commission Order No. 22-126, April 22, 2022, accessed at: https://apps.puc.state.or.us/orders/2022ords/22-126.pdf.
[3] EO 25-25 (3), p. 4.
[4] Docket No. AR 683, Commission Order No. 26-108, April 1, 2026, accessed at: https://apps.puc.state.or.us/orders/2026ords/26-108.pdf.

Following adoption of the emergency rules Staff and stakeholders returned to developing permanent rules for the larger issues list and that build off the temporary rules. Staff held two additional workshops, as well as offered multiple opportunities for comments. The intent was to bring parties together and search for consensus. The remainder of this Staff Report describes the draft rules resulting from that process. Staff's proposal incorporates much of the language of the temporary rules, with some modifications, and includes new requirements based on the full Phase 2 scope investigation. There has been consensus on many of the issues, but not all, as discussed below.

Rule Scope
Staff's proposal is targeted toward small generator interconnections processed outside of the cluster study process, on which Staff believes a state regulator has the most influence over timelines and practices. For PGE and IPC, this includes the existing Tier 4 process. For PAC, this will be the Tier 5 process addressed in Docket No. UM 2351. Staff's proposal updates the current Division 82 rules.

The temporary rules adopted in AR 683 include the following changes to Division 82:

1. Minimum requirements for the process, substance, and data requirements for third-party SIS'
2. 45-business-day timelines for System Impact Studies (SIS) and Facilities Studies (FaS),
3. A maximum 600-day timeline for completing system upgrades.
4. More clarity on the self-build option, and
5. The opportunity for limited operation pending construction of system upgrades needed for interconnection.

Staff's proposal for permanent rules leverages the above temporary rules, making refinements where needed. Refinements include options offering more flexibility on timing for several interconnection requirements, both for studies and construction. The approach to limited operations has been revamped as well, offering more options to interconnection applicants.

Staff's proposal includes additional permanent rules and policy direction to the utilities addressing the following:

1. Site Visits,
2. Communications requirements
3. Reporting requirements
4. Protection requirements (not in draft rules), and
5. Disconnect switches (not in draft rules).

Study Timelines
The temporary rules adopted in AR 683 included 45 business day timelines for both the SIS and FaS. Staff continues to support those timelines, but proposes rules with opportunities for modification where needed. The draft rules include two major exceptions to the study timelines, with both offering more flexibility for the interconnection applicants.

First, the draft rules allow a longer study timeline when no other project is impacted by delays in the studies. In such cases, at their choice, an applicant may request a longer study timeline for either/both the SIS and FaS. This option is included primarily in response to a circumstance identified by PGE, which is when an applicant may want to see what happens with a higher queued project going through the study phase. In such cases it may be beneficial for the lower queued project to wait for to avoid the potential for restudies.

The second exception to the 45-day requirement is for the FaS only. If an applicant requests a site visit prior to signing the interconnection agreement, the utility will have an additional 45 business days to complete the FaS, incorporating information from the site visit into the interconnection facilities cost estimates. Using this approach, the interconnection applicant should receive a firmer cost estimate for the interconnection facilities needed.

Staff continues to support study cost reductions if timelines are not met. When the SIS or FaS study delay is no more than 15 business days, the cost of the study will be reduced by 50 percent. When the delay exceeds 15 business days, the cost of the study will be reduced by 100 percent. The utility will be required to file a report with the Commission for any SIS or FaS that is provided to the applicant after the agreed-upon date. In the informal phase, Staff did not receive additional comments on taking a different approach to these timelines, or the potential cost reductions.

Construction Timelines
The temporary rules adopted in AR 683 established a 600-day timeline requirement for utilities to construct interconnection facilities and system upgrades for small generators processed outside of a cluster study. In the event a utility cannot agree to meet this timeline at the time the interconnection agreement is executed, the utility must allow for a self-build option for applicants or seek a waiver from the Commission.

If the utility fails to meet a 600-calendar day timeline or a longer timeline agreed to by the applicant, the applicant's total obligation to pay for interconnection costs would be reduced by five percent every 30 calendar days until the construction is complete. Staff originally proposed to reduce the amount owed by interconnection applicants if the Company exceeds the timeline stated in the Interconnection Agreement, but adjusted its

recommendation to reducing payment if the Company exceeds 600 days to mitigate the incentive for the Company to artificially set construction schedules at 600 days if a faster timeline is feasible.

Staff continues to believe 600 days from interconnection agreement to witness test, aka the construction period, strikes a reasonable balance, providing a significant benefit to Oregon small generators processed outside of the cluster study, while recognizing the current supply chain and the competing construction priorities facing utilities, such as wildfire mitigation investments.

The draft rules provide interconnecting parties some flexibility with respect to the construction timelines as well:

- The utility and applicant can mutually agree to a construction timeline that is longer than 600 days.
- The public utility has an option to request a waiver of the 600-day requirement for good cause prior to executing the Interconnection Agreement if the utility believes they cannot meet the requirement, and the applicant disagrees with extending the time.
- The utility can request a waiver for good cause if it has missed the 600-day timeline for a reason outside of the utility's control.

The utilities propose an automatic day-for-day extension to the 600-days when an interconnection applicant causes a delay in the process and/or an option to seek a waiver at any time a delay in the process has occurred outside of the utility's control. The utilities argue that without these provisions they will be held to timeline outside of their control and can no longer offer flexibility to interconnection applicants that miss milestones and timelines. Staff's proposal allows for utility waiver filings at the end of construction for any delays outside of the utility control. Such delays could include equipment procurement delays outside of the utility's control, however that would not include a utility's failure to timely order equipment.

Staff's proposal addresses utility concerns that they can no longer offer flexibility to interconnection applicants that miss timelines and milestones while keeping the utilities focused on meeting the 600-day timeline until it is clear they will miss it. Rather than allowing automatic day-for-day extensions or waivers prior to missing the deadline, Staff proposes that the utility must offer an applicant an amended IA incorporating day for day extension for missed milestones prior to removing them from the queue for breeching timelines and milestones.

Staff did not adopt the utility proposal to allow waivers after the IA is executed but before the 600-day construction timeline is missed. Staff believes requiring waivers at

the conclusion of the construction process is a reasonable approach to incent the utility and developer to work together to hit the 600-day timeline.

Staff would also like to address concerns raised by the utilities that developer-caused delays will lead to financial consequences for the utilities. Staff would not support reduction in interconnection costs for applicants who act in bad faith. It is Staff's position that delays caused by an applicant, such as missing milestones, could be good cause for the utility to not meet the timeline specified in the interconnection agreement. However, Staff hopes that the generators and public utilities will choose to address such issues (i.e., delays attributable to the generator) by mutually agreeing to extend the time for construction.

Limited Operation Interconnection
Limited operations offer an opportunity for generators to operate at a reduced capacity while interconnection upgrades are being constructed. These draft rules revise the approach used in the AR 683 rules on limited operations, offering more flexibility to interconnection applicants. The current proposal would allow applicants to request a limited operations study when requesting a SIS. Under PGE's proposal, the timeline for the SIS would be extended by 10 business days to address the limited operations request. Staff believes the timeline extension is reasonable and has incorporated it in the proposal.

Not all parties agree on this approach, PacifiCorp for instance recommends that limited operations be studied after an interconnection agreement is signed. If changes are made, the Company argues for the limited operations study to follow the FaS. This will avoid limited operations studies for interconnection applicants that do not proceed past the SIS; however, Staff believes the recommendation from PGE is more in line with national best practices and the approach recommended by IREC.

Staff believes it is not necessary for safe and reliable operations to wait until after the IA is signed to study opportunity for limited operations Concurrently studying limited operations with the SIS will enable actionable results sooner for developers. Instead of delaying the process, Staff's approach would should help streamline it.

Communications
Many delays seen in the interconnection process could be avoided through better communication between applicants and utilities. Staff has proposed rules memorializing communications protocols in the utility interconnection handbooks, in addition to other requirements. Having the protocols in the handbooks will provide more transparency to the interconnection process, as well as laying out specific standards for parties.
Staff is proposing a monthly meeting cadence for the utility and applicant following execution of the interconnection agreement. It is likely that meetings will need to be held

more frequently at certain stages, and less frequently at other stages. Staff's proposal recognizes this, allowing for cancellation of meetings that are not necessary (upon agreement) and an option to request additional meetings.

Based on feedback from the utilities, the draft rules include a new requirement for when a project changes ownership, with the new owners required to inform the interconnecting utility of such changes within 15 business days. Finally, Staff has included a provision to allow utilities to charge for reasonable communications costs.

Staff did not receive comments opposing or suggesting changes to the communications rules proposed.

Site Visits
Timing and practices of site visits were identified as a major opportunity to reduce delays and costs for interconnection applicants.. Staff's proposal, following much discussion, requires the utilities to offer a two-track approach to site visits. Under the current paradigm, utilities are not required to make site visits and typically wait until after the interconnection agreement is signed to conduct any needed site visit. Staff believes it is important to give interconnection applicants the opportunity for site visits during the study process to identify and address potential issues and requirements as early as possible. After discussion with parties, Staff was convinced that such visits are only necessary in most cases for Tier 4 applicants.

The two-track approach will allow the current practice of conducting site visits after an interconnection agreement is executed. However, the draft rules include an option for the interconnection application to request a site visit take place during the FaS. Under this approach the utility would use information gleaned from the site visit in preparing the cost estimate in the FaS, as opposed to the desktop exercise used under the traditional approach. Following workshop discussion and comments, Staff received proposed language from a coalition of parties, OSSIA, REC, and PacifiCorp, which would allow site visits during the FaS stage, with extended timelines to complete the study. This second option would allow an extension of the FaS timeline, increasing it by 45 business days, from 45 to 90 business days.

Staff recognizes the added cost to utilities to perform site visits, particularly when projects are less certain, but appreciates the balanced solution arrived at by stakeholders.

One other option incorporated into the draft rules concerns the use of drones in conducting site visits. Staff did not want to limit any approaches that could improve the process while lowering the overall costs. As such there is an option, if parties are in agreement.

Reporting Requirements
Staff's draft rules also include new quarterly reporting requirements under OAR 860-082-0065. Staff's intention is that these reports will surface problems in the interconnection process sooner, rather than later. In discussion and comments from parties, there does not seem to be any objection to more detailed reports. PGE offered additional data points these reports could contain in their May 1 comments. Staff believes those data points have merit, and they are included in the draft report fields, included as Attachment 4.

PGE also recommends revisiting the reports in three years to see if they are meeting the concerns raised. Staff believes this approach is reasonable. As such, Staff has left the requirements in the OAR less prescriptive, allowing changes to the reports without needing a rulemaking to adjustment data collected by the reports.

Protection Schemes
Direct Transfer Trip (DTT) allows immediate disconnection of a generator from the utility's system. Installation of DTT can be costly and is of concern to small generator interconnections. Staff is not proposing to introduce new rules regarding DTT, but rather recommends that the Commission direct utilities include in their handbooks a transparent and reasonable approach to identify when DTT is required. A detailed discussion on Staff's recommendation is in Attachment 2.

Net metering installations
Stakeholders raised concerns related to the increased cost resulting from the requirement by some utilities for customer generators to install multiple disconnect switches for a single net metering interconnection. Staff is not proposing to change or introduce new rules regarding disconnect switches, but rather recommends that the Commission direct utilities include in their handbooks an option for the customer to install a single disconnect switch per customer interconnection, consistent with certain conditions proposed by Staff in its discussion on the topic in Attachment 3.

Conclusion

Staff believes its draft rules, as proposed, are targeted, balanced, and feasible. The draft rules incorporate and build off the temporary rules approved by the Commission in AR 683 with modifications addressing identified issues. The proposal also addresses remaining issues from Phase 2 of UM 2111. Staff believes the combination of the rules proposed will help expedited the interconnection process.

Further, Staff believes the Commission has authority to establish specific timelines to perform interconnection studies and construct system upgrades and Staff believes imposing these requirements will expedite the interconnection process.

PROPOSED COMMISSION MOTION:

Staff recommends that the Commission approve Staff's request to open a formal rulemaking and issue a notice of proposed rulemaking to adopt changes to Division 82 Small Generator Interconnection Rules. The proposed draft rule revisions are included in Attachment 1.

Staff also recommends the Commission direct investor-owned utilities in Oregon to include in their interconnection handbooks, by the annual handbook update in 2027:

1. A detailed description of the approach they will use in identifying DTT in small generator interconnection studies, consistent with the criteria in Attachment 2-1.
2. An option for the net metering customer to install a single disconnect switch for all systems behind one meter under the conditions proposed by Staff in Attachment 3.

Attachment 1

Staff Proposal

Chapter 860
Division 82
SMALL GENERATOR INTERCONNECTION RULES
860-082-0005
Scope and Applicability
(1) OAR 860-082-0005 through 860-082-0085 (the “small generator interconnection rules”) govern the interconnection of a small generator facility with a nameplate rating of 10 megawatts or less to a public utility’s transmission or distribution system. These rules do not apply if the interconnection between the small generator facility and the public utility is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

(2) Except as specified in OAR 860-082-0025(1)(b), the small generator interconnection rules do not apply retroactively to a small generator facility that was interconnected to a public utility’s transmission or distribution system prior to the effective date of the small generator interconnection rules (an “existing small generator facility”). These rules become applicable to an existing small generator facility at the expiration of the agreement governing the terms of the interconnection of the existing small generator facility to the interconnected public utility’s transmission or distribution system. If an existing agreement does not have an expiration date, then the small generator interconnection rules become applicable to the existing small generator facility 10 years after the effective date of the rules. An existing small generator facility must submit an application under OAR 860-082-0025(1)(e) to the interconnected public utility no later than 60 business days before the date that the small generator interconnection rules become applicable.

(3) Except where explicitly noted in OAR chapter 860, division 039, the small generator interconnection rules do not apply to the interconnection of a net metering facility, which is governed by OAR chapter 860, division 039.

(4) A small generator facility that qualifies as a “small power production facility” under OAR 860-029-0010(25) must also comply with the rules in OAR chapter 860, division 029. If there is a conflict between the small generator interconnection rules and the rules in OAR chapter 860, division 029, then the small generator interconnection rules control.
Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
History:
PUC 4-2024, amend filed 04/09/2024, effective 04/09/2024
PUC 10-2009, f. & cert. ef. 8-26-09

860-082-0010

Waiver

(1) Upon request or its own motion, the Commission may waive any of the Division 082 rules for good cause shown. A request for waiver must be made in writing, unless otherwise allowed by the Commission.
(2) A public utility and an applicant or interconnection customer may agree to reasonable extensions to the required timelines in these rules without requesting a waiver from the Commission~~.~~, except for extensions to study timelines, unless the extensions are requested by the applicant as specified in OAR 860-082-0060.

(a) If a public utility and an applicant or interconnection customer are unable to agree to waive a timeline, then the public utility, applicant, or interconnection customer may request that the Commission grant a waiver.

(b) In deciding whether to grant a waiver of a timeline, the Commission will consider the number of pending applications for interconnection review and the type of applications, including review level, facility type, and facility size.

(c) Waiver of a timeline, whether by agreement or Commission order, does not affect an application's queue position.

Statutory/Other Authority: ORS 183, 756 & 757
Statutes/Other Implemented: ORS 756.040 & 756.060
History:
PUC 6-2011, f. & cert. ef. 9-14-11
PUC 10-2009, f. & cert. ef. 8-26-09

860-082-0015
Definitions

As used in OAR 860-082-0005 through 860-082-0085:

(1) "Adverse system impact" means a negative effect caused by the interconnection of a small generator facility that may compromise the safety or reliability of a transmission or distribution system.

(2) "Affected system" means a transmission or distribution system, not owned or operated by the interconnecting public utility, which may experience an adverse system impact from the interconnection of a small generator facility.

(3) "Aggregated export capacity" means the total combined export capacity of:

(a) A proposed small generator facility;

(b) Existing small generator facilities, net metering facilities, FERC jurisdictional generators, and state jurisdictional generators with a nameplate rating greater than 10 megawatts; and

(c) Small generator facilities, net metering facilities, FERC jurisdictional generators, and state jurisdictional generators with a nameplate rating greater than 10 megawatts that have pending completed applications with higher queue positions than the proposed small generator facility.

(4) “Aggregated nameplate rating” means the total combined nameplate rating of:

(a) A proposed small generator facility;

(b) Existing small generator facilities, net metering facilities, FERC jurisdictional generators, and state jurisdictional generators with a nameplate rating greater than 10 megawatts; and

(c) Small generator facilities, net metering facilities, FERC jurisdictional generators, and state jurisdictional generators with a nameplate rating greater than 10 megawatts that have pending completed applications with higher queue positions than the proposed small generator facility.

(5) “Applicant” means a person who has submitted an application to interconnect a small generator facility to a public utility’s transmission or distribution system.

(6) “Application” means a written request to interconnect a small generator facility with a public utility’s transmission or distribution system, which must follow the standard form developed by the public utility and approved by the Commission.

(7) “Area network” means a type of distribution system served by multiple transformers interconnected in an electrical network circuit in order to provide high reliability of service.

(8) “Certificate of completion” means a certificate signed by an applicant and an interconnecting public utility attesting that a small generator facility is complete, meets the applicable requirements of the small generator interconnection rules, has passed all applicable federal, state, and local inspection requirements, and is certified as physically ready for operation. A certificate of completion includes the “as built” specifications and initial settings for the small generator facility and its associated interconnection equipment.

(9) "Communication Protocols" means a plan established and maintained by utilities that set expectations for utility and applicant communications, including general and electronic mail, phone, and virtual and in-person meetings.

(~~9~~10) "Distribution system" means the portion of an electric system that delivers electricity from transformation points on the transmission system to points of connection on a customer's premises.

(~~10~~11) "Energy storage system" means a mechanical, electrical, or electrochemical means to store and release electrical energy, and its associated interconnection and control equipment. For the purposes of these rules, an energy storage system can be considered part of a small generator facility or a small generator facility in whole that operates in parallel with the distribution system.

(~~11~~12) "Export capacity" means the amount of power that can be transferred from the small generator facility to the distribution system. Export capacity is either the nameplate rating, or a lower amount if limited using an acceptable means identified in OAR 860-082-0033.

(~~12~~13) "Fault current" means an electrical current that flows through a circuit during a fault condition. A fault condition occurs when one or more electrical conductors contact ground or each other. Types of faults include phase to ground, double-phase to ground, three-phase to ground, phase to phase, and three-phase.

(~~13~~14) "Field-tested equipment" means interconnection equipment that is identical to equipment that was approved by the interconnecting public utility for a different small generator facility interconnection and successfully completed a witness test under the requirements included in the current version of the public utility's interconnection requirements handbook before the date of the submission of the current application.

(~~14~~15) "Host load" means electrical power, less the small generator facility auxiliary load, consumed by the customer at the location where the small generator facility is connected.

(~~15~~16) "IEEE 1547" means the standards published in the 2018 edition of the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547, titled "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces" and approved by the IEEE SA Standards Board on February 15, 2018.

(~~16~~17) “IEEE 1547.1” means the standards published in the 2020 edition of the IEEE Standard 1547.1, titled “IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems and Associated Interfaces” and approved by the IEEE SA Standards Board on March 5, 2020.

(~~17~~18) “Inadvertent export” means the unscheduled export of active power from a small generator facility, exceeding a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.

(~~18~~19) “Interconnection agreement” means a contract between an applicant or interconnection customer and an interconnecting public utility that governs the interconnection of a small generator facility to the public utility’s transmission or distribution system and the ongoing operation of the small generator facility after it is interconnected. An interconnection agreement will follow the standard form agreement developed by the public utility and filed with the Commission.

(~~19~~20) “Interconnection customer” means a person with one or more small generator facilities interconnected to a public utility’s transmission or distribution system.

(~~20~~21) “Interconnection equipment” means a group of components or an integrated system provided by an interconnection customer or applicant to connect a small generator facility to a public utility’s transmission or distribution system.

(~~21~~22) “Interconnection facilities” means the facilities and equipment required by a public utility to accommodate the interconnection of a small generator facility to the public utility’s transmission or distribution system and used exclusively for that interconnection. Interconnection facilities do not include system upgrades.

(~~22~~23) "Interconnection facilities study" means a study conducted by a utility for the customer-generator that determines the additional or upgraded distribution system facilities, the cost of those facilities, and the time schedule required to interconnect the small generator facility to the public utility’s distribution system.

(~~23~~24) “Interconnection service” means service provided by an interconnecting public utility to an interconnection customer.

(~~24~~25) “Lab-tested equipment” means interconnection equipment that has been designed to comply with IEEE 1547, tested in accordance with IEEE 1547.1, and certified and labeled as compliant with these IEEE standards at the point of manufacture by a nationally recognized testing lab. For interconnection equipment to be considered lab-tested equipment under these rules, the equipment must be used in a manner consistent with the certification.

(~~25~~26) “Limited export” means the exporting capability of a small generator facility whose export capacity is limited by the use of any configuration or operating mode described in OAR 860-082-0033.

(27) “Limited Operations” means operation of a small generator facility at a reduced export capacity, utilizing one or more export control methods as required, permitted under OAR 860-082-0033.

(~~26~~28) “Line section” means that portion of a public utility’s transmission or distribution system that is connected to an interconnection customer and bounded by automatic sectionalizing devices or the end of a distribution line.

(~~27~~29) “Minor equipment modification” means a change to a small generator facility or its associated interconnection equipment that:

(a) Includes a change or replacement of equipment that is a like-kind substitution in size, ratings, impedances, efficiencies, or capabilities of the equipment specified in the original interconnection application. Minor variations that do not affect safety, performance, or interoperability are acceptable;

(b) Includes a replacement of existing inverters with new inverters that conform to standards in effect at the time of replacement;

(c) Includes a reduction in the nameplate rating and/or export capacity of the small generator facility of 10 percent or less; or

(d) For changes not specified in subsections (a) through (c) of this definition, the change must not, in the interconnecting public utility’s reasonable opinion, have a material impact on the safety or reliability of the public utility’s transmission or distribution system or an affected system.

(e) Applicants must inform the interconnecting public utility of minor equipment modifications, prior to making the change.

(~~28~~30) “Nameplate rating” means the sum total of maximum rated power output of all of a small generator facility’s constituent generating units and/or energy storage systems as identified on the manufacturer nameplate in Alternating Current (AC), regardless of whether it is limited by any approved means. For a generating unit that uses an inverter to change direct current energy supplied to an AC quantity, the nameplate rating will be the manufacturer’s AC output rating for the inverter(s).

(~~29~~31) “Nationally recognized testing laboratory” or “NRTL” means a qualified private organization that performs independent safety testing and product certification. Each NRTL must meet the requirements set forth by the United States Occupational Safety and Health Administration.

(~~30~~32) “Net metering facility” has the meaning set forth in ORS 757.300(1)(d).

(~~31~~33) “Non-export or non-exporting” means when the small generator facility is sized and designed and operated using any of the methods in OAR 860-082-0033, such that the output is used for host load only and no electrical energy (except for any inadvertent export) is transferred from the small generator facility to the distribution system.

(~~32~~34) “Pending completed application” means an application for interconnection of a small generator facility, a net metering facility, or a FERC jurisdictional generator that an interconnecting public utility has deemed complete.

(~~33~~35) “Person” includes individuals, joint ventures, partnerships, corporations and associations or their officers, employees, agents, lessees, assignees, trustees or receivers, as supplemented to include governmental entities.

(~~34~~36) “Point of interconnection” means the point where a small generator facility is electrically connected to a public utility’s transmission or distribution system. This term has the same meaning as “point of common coupling” as defined in IEEE 1547.

(~~35~~37) "Power control system” means systems or devices which electronically limit or control steady state currents to a programmable limit.

(~~36~~38) “Primary line” means a distribution line with an operating voltage greater than 600 volts.

(~~37~~39) “Public utility” has the meaning set forth in ORS 757.005 and is limited to a public utility that provides electric service.

(~~38~~40) “Queue position” means the rank of a pending completed application, relative to all other pending completed applications, that is established based on the date and time that the interconnecting public utility receives the completed applications, including application fees.

(~~39~~41) “Reference point of applicability” (RPA) means a location proximate to the generation where the interconnection and interoperability performance requirements, as specified by IEEE 1547, apply.

(~~40~~42) “Relevant minimum load” means the lowest measured load coincident with the generating facility’s production. For solar-only facilities, this is the daytime minimum load (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems).

(~~41~~43) “Scoping meeting” means an initial meeting between representatives of an applicant and an interconnecting public utility that is conducted to discuss the RPA, to discuss alternative interconnection options; to exchange information, including any relevant transmission or distribution system data and earlier studies that would reasonably be expected to affect the interconnection options; to analyze such information; and to determine the potentially feasible points of interconnection.

(~~42~~44) “Secondary line” means a service line with an operating voltage of 600 volts or less.

(45) “Site visit” means a meeting at the proposed location of the small generator facility between representatives of an applicant and an interconnecting public utility that is conducted to address all relevant site issues including, but not limited to, site engineering, permitting, easements, and any other required issues. Site visits may be conducted via drone, if parties agree.

(~~43~~46) “Small generator facility” means a facility that operates in parallel with the distribution system for the production of electrical energy that has a maximum installed instantaneous power production capacity of the completed Facility, expressed in MW (AC), and measured at the Point of Interconnection of 10 MW, when operated in compliance with the Generation Interconnection Agreement and consistent with the recommended power factor and operating parameters provided by the manufacturer of the generator, inverters, energy storage devices, or other equipment within the Facility affecting the Facility's capability to deliver useful electric energy to the grid at the Point of Interconnection,

(~~44~~47) “Spot network” means a type of transmission or distribution system that uses two or more intertied transformers protected by network protectors to supply an electrical network circuit. A spot network may be used to supply power to a single customer or a small group of customers.

(~~45~~48) “System upgrade” means an addition or modification to a public utility’s transmission or distribution system or to an affected system that is required to accommodate the interconnection of a small generator facility.

(~~46~~49) “Transmission line” means any electric line operating at or above 50,000 volts.

(~~47~~50) “Transmission system” means a public utility’s high voltage facilities and equipment used to transport bulk power or to provide transmission service under the public utility’s open access transmission tariff.

(~~48~~51) “Witness test” means the on-site visual verification of the interconnection installation and commissioning as required in IEEE 1547. For interconnection equipment that does not meet the definition of lab-tested equipment, the witness test may, at the discretion of the public utility, also include a type test and small generator facility evaluation according to IEEE 1547 as applicable to the specific interconnection equipment used.

(~~49~~52) “Written notice” means a required notice sent by the public utility via electronic mail if the customer-generator has provided a functioning electronic mail address. If the customer-generator has not provided a functioning electronic mail address or has requested in writing to be notified by United States mail, then written notices from the public utility must be sent via First Class United States mail to the notification address provided by the customer-generator. The public utility is deemed to have fulfilled its duty to respond under these rules on the day it sends the customer-generator notice via electronic mail or deposits such notice in First Class mail. The customer-generator is responsible for informing the public utility of any changes to its notification address.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
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860-082-0020
Pre-Application Process

(1) Each public utility must designate an employee or office from which relevant information about the small generator interconnection process, the public utility’s transmission or distribution system, and affected systems may be obtained through informal requests for a potential applicant proposing a small generator facility at a specific site. The public utility must post contact information for the employee or office on the public utility’s website. The information provided by the public utility in response to a potential applicant’s request must include relevant existing studies and other materials that may be used to understand the feasibility of interconnecting a small generator facility at a particular point on the public utility’s transmission or distribution system. The public utility must comply with reasonable requests for access to or copies of such information, except to the extent that providing such materials would violate

security requirements, confidentiality obligations to third parties, or be contrary to federal or state regulations. The public utility may require a person to sign a confidentiality agreement if required to protect confidential or proprietary information. For a potential small generator facility requiring Tier 4 review, and at the potential applicant's request, the public utility must meet with the potential applicant to exchange information. A public utility employee with relevant technical expertise must attend any such meeting.

(2) A person requesting information under section (1) must reimburse the public utility for the reasonable costs of gathering and copying the requested information.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
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860-082-0025
Applications to Interconnect a Small Generator Facility

(1) A person may not interconnect a small generator facility to a public utility's transmission or distribution system without authorization from the public utility.

(a) A person proposing to interconnect a new small generator facility to a public utility's transmission or distribution system must submit an application to the public utility.

(b) A person with an existing interconnected small generator facility who proposes to make any change to the facility, other than a minor equipment modification, must submit an application to the public utility. This includes changes affecting the nameplate rating of the existing interconnected small generator facility or the output capacity authorized in the agreement governing the terms of the interconnection.

(c) An applicant with a pending completed application to interconnect a small generator facility must submit a new application if the applicant proposes to make any change to the small generator facility other than a minor equipment modification. This includes changes affecting the nameplate rating of the proposed small generator facility.

(A) The applicant relinquishes the queue position assigned to the pending completed application, and the public utility assigns a new queue position based on the date and time the public utility receives the new application.

(B) If the new application is submitted within 30 business days of the date of submission of the original application, then the public utility must apply the original application fee to the application fee required for the new application.

(d) A person with a pending completed application to interconnect a net metering facility or a FERC jurisdictional generator who proposes to change the facility to a small generator facility must submit a new application under the small generator interconnection rules.

(A) The applicant relinquishes the queue position assigned to the pending completed application, and the public utility assigns a new queue position based on the date and time that the interconnecting public utility receives the small generator interconnection application.

(B) If the small generator interconnection application is received within 30 business days of the date of submission of the original net metering or FERC jurisdictional generator interconnection application, then the public utility must apply the original application fee to the application fee required for the new application.

(e) An interconnection customer must submit an application to renew an existing small generator facility interconnection before the expiration of the interconnection agreement between the interconnection customer and the interconnected public utility. The application must be submitted no later than 60 business days before the interconnection agreement's expiration date.

(A) A public utility may not unreasonably refuse to grant expedited review of an application to renew an existing small generator facility interconnection if there have been no changes to the small generator facility other than minor equipment modifications.

(B) A public utility may not require an existing small generator facility to undergo Tier 4 review if there have been no changes to the small generator facility other than minor equipment modifications and there have been no material changes to the portion of the public utility's transmission or distribution system affected by the interconnection of the small generator facility.

(C) A public utility may require the interconnection customer to pay for interconnection facilities, system upgrades, or changes to the small generator facility or its associated interconnection equipment that are necessary to bring the small generator facility interconnection into compliance with the small generator interconnection rules or IEEE 1547 or 1547.1.

(D) If the public utility has not completed its review of an application to renew and a new interconnection agreement is not signed before the expiration of the current interconnection agreement governing the interconnection of an existing small generator facility to a public utility's transmission or distribution system, then the current interconnection agreement remains in effect until the renewal process is completed and a new interconnection agreement is signed.

(2) All applications must be made using the appropriate application form and must follow the standard form applications developed by the public utility and approved by the Commission. The public utility must provide separate application forms for review under Tier 1 and for review under Tiers 2, 3, and 4. The Tier 1 application form must include an unexecuted interconnection agreement. The public utility must provide a copy of an application form to any person upon request and must post copies of the application forms on the public utility's website.

(a) Applicants must use the Tier 1 application form for a small generator facility that meets the requirements of OAR 860-082-0045(1).

(b) All applicants may use the application form for Tiers 2, 3, or 4.

(3) A public utility may require payment of a nonrefundable application processing fee. The amount of the fee depends upon the review tier requested in the application and is intended to cover the reasonable costs of processing and evaluating the application.

(a) The application fee may not exceed $100 for Tier 1 review, $500 for Tier 2 review, and $1,000 for review under Tiers 3 and 4.

(b) An applicant must pay the reasonable costs incurred by the public utility to perform any studies and engineering evaluations permitted by these rules and necessary to evaluate the proposed application to interconnect. Before the public utility may assess any costs in excess of the application fee, the public utility must receive written authorization from the applicant. If the applicant does not authorize the additional costs, then the application is deemed withdrawn, and the original application fee is forfeited.

(c) If an application is denied at one review tier, and the applicant resubmits the application at a higher review tier within 15 business days after the date the applicant received notification of the denial, then the applicant maintains the queue position assigned to the original application and the public utility must apply the original application fee and any other fees paid in conjunction with the original application to the fees applicable to the resubmitted application.

(4) If an applicant proposes to interconnect multiple small generator facilities to the public utility's transmission or distribution system at a single point of interconnection, then the public utility must evaluate the applications based on the combined total nameplate rating for all of the small generator facilities. If the combined total nameplate rating exceeds 10 megawatts, then the small generator interconnection rules do not apply.

(5) An applicant must provide documentation of site control with an interconnection application. Site control may be demonstrated through ownership of the site, a leasehold interest in the site, or an option or other right to develop the site for the purpose of constructing the small generator facility. Site control may be documented by a property tax bill, deed, lease agreement, or other legally binding contract.

(6) A public utility may propose to interconnect multiple small generator facilities at a single point of interconnection to minimize costs, and an affected applicant or interconnection customer may not unreasonably refuse such a proposal. An applicant or interconnection customer may, however, elect to maintain a separate point of interconnection if the applicant or interconnection customer agrees to pay the entire cost of the separate interconnection facilities.

(7) Application review process.

(a) Within 10 business days of receipt of an application to interconnect a small generator facility, the interconnecting public utility must provide written notice to the applicant stating whether the application is complete.

(A) If the application is incomplete, then the public utility must provide the applicant with a detailed list of the information needed to complete the application. An application is deemed complete when the public utility receives the listed information. The applicant must provide the listed information within 10 business days of receipt of the list, or the application is deemed withdrawn.

(B) If a public utility does not have a record of receipt of an application or cannot locate an application, then the applicant must provide an additional copy of the application to the public utility. If the applicant can demonstrate that a complete application was originally delivered to the public utility at a particular time on a particular date, then the public utility must assign a queue position to the application based on the original time and date of delivery.

(b) Once the public utility deems an application to be complete, the public utility must assign the application a queue position. An applicant must meet all applicable deadlines in the small generator interconnection rules to maintain its queue position unless the

deadlines have been waived by agreement with the interconnecting public utility or by Commission order.

(c) If the public utility determines during the evaluation process that supplemental or clarifying information is required, then the public utility must request the information from the applicant, and the applicant must provide the requested information within 15 business days of the request, or the application will be deemed withdrawn. The time necessary to complete the evaluation of the application may be extended by the time required for the receipt of the additional information. Requests for information do not affect the applicant's queue position.

(d) A public utility must use IEEE 1547 and IEEE 1547.1 to evaluate small generator interconnection applications unless otherwise specified in these rules or unless the Commission grants a waiver to use different or additional standards.

(e) Reference Point of Applicability Review.

(A) For Tier 4 applications, the public utility will raise any concerns about the RPA in the scoping meeting.

(B) For Tier 1 through Tier 3 applications, the public utility notifies an applicant if the proposed RPA is appropriate when it provides screen results. If the RPA is inappropriate the public utility will notify the applicant in writing, including an explanation as to why it requires correction. The applicant must resubmit the application with the corrected RPA within ten business days. If the applicant does not provide the appropriate RPA, a request for an extension of time, or request an applicant options meeting within the deadline, the application will be deemed withdrawn.

(f) Interconnection Agreement. If the proposed interconnection is approved and requires no construction of facilities by the public utility, the public utility must provide the applicant an executed interconnection agreement no later than five business days after approving the interconnection. If the proposed interconnection is approved and requires construction of facilities, the public utility must provide the applicant an executed interconnection agreement, along with a non-binding good faith cost estimate and construction schedule for any required upgrades, no later than 15 business days after approving the interconnection. If the applicant does not return a countersigned interconnection agreement and any required deposit not to exceed the amount in OAR 860-082-0035(5)(a) to the public utility, or request negotiation of a non-standard interconnection agreement, within 15 business days of receipt of an executed interconnection agreement, the application is deemed withdrawn.

(A) An applicant or a public utility is entitled to the terms in the standard form agreement but may choose to negotiate for different terms.

(B) If negotiated changes to a standard interconnection agreement are materially inconsistent with the small generator interconnection rules, then the applicant and the public utility must seek Commission approval of the negotiated interconnection agreement.

(g) The applicant must provide the public utility written notice at least 20 business days before the planned commissioning for the small generator facility.

(A) The public utility has the option of conducting a witness test at a mutually agreeable time within 10 business days of receipt of the certificate of completion.

(B) The public utility must provide written notice to the applicant indicating whether the public utility plans to conduct a witness test or will waive the witness test within three business days of receipt of the certificate of completion.

(C) If the public utility notifies the applicant that it plans to conduct a witness test but fails to conduct the witness test within 10 business days of receipt of the certificate of completion or within a time otherwise agreed upon by the applicant and the public utility, then the witness test is deemed waived.

(D) If the witness test is conducted and is successful, or if the public utility waives the witness test, the public utility must provide the countersigned certificate of completion within five business days of conducting the witness test or waiver of witness test.

(E) If the witness test is conducted and is not acceptable to the public utility, then the public utility must provide written notice to the applicant describing the deficiencies within five business days of conducting the witness test. The public utility must give the applicant 20 business days from the date of the applicant’s receipt of the notice to resolve the deficiencies. If the applicant fails to resolve the deficiencies to the reasonable satisfaction of the public utility within 20 business days or at a mutually agreeable time, then the application is deemed withdrawn.

(h) A public utility must meet all applicable deadlines in the small generator interconnection rules unless the deadlines have been waived by agreement with an applicant or interconnection customer or by Commission order. If the public utility cannot meet an applicable deadline, then the public utility must provide written notice to the applicant or interconnection customer explaining the reasons for the failure to meet the deadline and an estimated alternative deadline. A public utility’s failure to meet an applicable deadline does not affect an applicant’s queue position.

(i) At least one site visit is required for Tier 4 or 5 applicants prior to interconnection for the purpose of identifying and addressing all relevant site issues including, but not limited to site engineering, permitting, easements, and any other pertinent matters.
(A) If requested by the applicant the required site visit shall occur during the Facilities Study. Otherwise the site visit will occur or no later than 60 calendar days following:
(i) the public utility's receipt of the Interconnection Customer's initial progress payment or deposit detailed in the Interconnection Agreement; and
(ii) the public utility's receipt of the Interconnection Customer's initial design package for the generation resource being interconnected.
(B) The site visit may be scheduled later than the times identified above by agreement of the parties but must occur before the Interconnection Customer begins construction of the facilities on its side of the point of interconnection.
(C) The reasonable costs of site visits after execution of the Interconnection Agreement will be added to the total interconnection costs to be paid by the Interconnection Customer. The utility will provide the applicant with a separate accounting of site visit costs.
(D) If the Interconnection Customer requests the site visit to occur during the Facilities Study process:
(i) the Interconnection Customer will pay for the public utility's costs for conducting the site visit when it executes the Facilities Study agreement; and
(ii) the time to complete the Facilities Study may increase to 90 business days at request of public utility.
(iii) The public utility may request that the applicant provide the public utility additional design/engineering information and have personnel with certain types of expertise available. The applicant and public utility will discuss and seek to reach agreement on the information requirements and necessary personnel before a site visit is scheduled.
(iv) Applicants shall provide all relevant site and property information in advance of the site visit, including but not limited to property ownership information, site plans, proposed equipment locations, easement information, and the preferred point of interconnection, as applicable at least 10 business days prior to the site visit. Any delay resulting from incomplete, inaccurate, or untimely applicant-provided information shall result in a corresponding day-for-day extension of the study timeline until such information has been provided to and validated by the utility.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
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860-082-0030
Construction, Operation, Maintenance, and Testing of Small Generator Facilities

(1) IEEE 1547. An interconnection customer or applicant must construct, operate, and maintain a small generator facility and its associated interconnection equipment in compliance with IEEE 1547 and 1547.1. New interconnection applicants will be required to use IEEE 1547-2018 compliant equipment by no earlier than June 1, 2024. For purposes of OAR 860-082-0030, capitalized terms not otherwise defined in Division 082 have the meaning set forth in IEEE 1547.

(a) Small generator facilities compliant with IEEE 1547 must conform with the following minimum requirements:

(A) Abnormal performance requirements: Category III Ride-Through capabilities must be supported for inverter-based small generator facilities. Rotating small generator facilities must meet Category I Ride-Through capabilities, at minimum.

(B) Normal performance requirements: Inverter-based small generator facilities must meet reactive power requirements of IEEE 1547 Category B. Rotating small generator facilities must meet Category A, and may meet Category B.

(C) Inverter-based interconnection equipment will be tested to and certified as being compliant with UL 1741 Third Edition, Supplement SB, by a NRTL. Equipment that is not certified by a NRTL may require additional evaluation and commissioning testing to confirm compliance with IEEE 1547.

(b) Interconnection requirements handbook. Each public utility must post an interconnection requirements handbook on its public website. Prior to revising its handbook, a utility must provide public notice on its website and use best efforts to notify organizations representing interconnection customers as specified and periodically updated in the handbook. The utility must provide a minimum of 30 days for interested persons to comment, and the utility must respond within 30 days to any comments received and make its responses public.

(c) Preferred default settings. A public utility must allow small generator facilities to interconnect using the public utility's preferred default settings, except when the application reviewed under Tier 4, OAR 860-082-0060, or the application fails the Tier 1, Tier 2, or Tier 3 approval criteria in OAR 860-082-0045(2), OAR 860-082-0050(2), or OAR 860-082-0055(2). Interconnection requirements handbooks must include preferred default settings. As applicable, the following must be identified in the interconnection requirements handbook:

(A) Voltage and frequency trip settings;

(B) Frequency droop settings;

(C) Activated reactive power control function and default settings;

(D) Voltage active power (volt-watt) mode activation and default setting; and

(E) Communication protocols and ports requirements.

(2) The applicant must provide written notice to the interconnecting public utility 10 business days before beginning operation of an approved small generator facility.

(3) Before beginning operation of a small generator facility, an interconnection customer or applicant must receive approval of the facility under the small generator interconnection rules and must execute an interconnection agreement with the interconnecting public utility. Applicants or interconnection customers are entitled to a 20-year term for an interconnection agreement, or if the interconnection customer and the public utility have entered a separate Power Purchase Agreement for a specified period of time, to a term that coincides with the length of such Power Purchase Agreement.

(4) A small generator facility must be capable of being isolated from the interconnecting public utility's transmission or distribution system. An interconnection customer may not disable an isolation device without the prior written consent of the interconnected public utility.

(a) For a small generator facility interconnecting to a primary line, the interconnection customer or applicant must use a lockable, visible-break isolation device readily accessible to the public utility.

(b) For a small generator facility interconnecting to a secondary line, the interconnection customer or applicant must use a lockable isolation device that is readily accessible by the public utility. The status of the isolation device must be clearly indicated. An exception from the requirement to use a lockable isolation device is allowed for a small generator facility that has a maximum total output of 30 amperes or less; is connected to a secondary line; uses lab-tested, inverter-based interconnection equipment; and is interconnected to the distribution system through a metered service owned by the interconnected public utility. In this limited case, the meter base may serve as the required isolation device if it is readily accessible to the public utility.

(A) A draw-out type circuit breaker with the provision for padlocking at the draw-out position can be considered an isolation device.

(B) The interconnection customer or applicant may elect to provide the public utility access to an isolation device that is contained in a building or area that may be unoccupied and locked or not otherwise readily accessible to the public utility. The interconnection customer or applicant must provide a lockbox capable of accepting a lock provided by the public utility that provides ready access to the isolation device. The interconnection customer or applicant must install the lockbox in a location that is readily accessible by the public utility and must affix a placard in a location acceptable to the public utility that provides clear instructions to utility personnel on how to access the isolation device.

(c) Other than the exception in (4)(b), all isolation devices must be installed, owned, and maintained by the interconnection customer or applicant; must be capable of interrupting the full load of the small generator facility; and must be located between the small generator facility and the point of interconnection.

(5) An interconnecting public utility must have access to an interconnection customer's or an applicant's premises for any reasonable purpose related to an interconnection application or an interconnected small generator facility. The public utility must request access at reasonable hours and upon reasonable notice. In the event of an emergency or hazardous condition, the public utility may access the interconnection customer's or applicant's premises at any time without prior notice, but the public utility must provide written notice within five business days after entering the interconnection customer's or applicant's premises that describes the date of entry, the purpose of entry, and any actions performed on the premises.

(6) When a small generator facility undergoes maintenance or testing in compliance with the small generator interconnection rules, IEEE 1547, or IEEE 1547.1, the interconnection customer must retain written records for at least seven years documenting the maintenance and the results of testing. The interconnection customer must provide copies of these records to the interconnected public utility upon request.

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860-082-0033
Export Controls

(1) If a small generator facility uses any configuration or operating mode in section (3) to limit the export of electrical power across the Point of Interconnection, then the export capacity is only the amount capable of being exported (not including any Inadvertent export). To prevent impacts on system safety and reliability, any inadvertent export from a small generator facility must comply with the limits identified in this rule. The export capacity specified by the interconnection customer in the application will subsequently be included as a limitation in the interconnection agreement.

(2) An application proposing to use a configuration or operating mode to limit the export of electrical power across the Point of Interconnection must include proposed control and/or protection settings.

(3) Acceptable export control methods.

(a) Export control methods for non-exporting small generator facility:

(A) Reverse Power Protection (Device 32R): To limit export of power across the Point of Interconnection, a reverse power protective function is implemented using a utility grade protective relay. The default setting for this protective function is 0.1 percent (export) of the service transformer's nominal base nameplate power rating, with a maximum 2.0 second time delay to limit inadvertent export. When a project is located on a circuit using high-speed reclosing, the utility may require a maximum delay of less than 2.0 seconds to safely facilitate the reclosing. To minimize the need for case-by-case design, which shall remain available, the utility handbook must provide:

(i) The rationale and standards that interconnection applications must meet;

(ii) A list of specific additional equipment that, if installed, will satisfy the requirement; and

(iii) A list of any inverter specifications and options that, if configured, will satisfy the requirement without the need for additional equipment.

(B) Minimum Power Protection (Device 32F): To limit export of power across the Point of Interconnection, a minimum import protective function is implemented utilizing a utility grade protective relay. The default setting for this protective function is 5 percent (import) of the small generator facility’s total nameplate rating, with a maximum 2.0 second time delay to limit Inadvertent export. When a project is located on a circuit using high-speed reclosing, the public utility may require a maximum delay of less than 2.0 seconds to safely facilitate the reclosing. To minimize the need for case-by-case design, which shall remain available, the utility handbook must provide:

(i) The rationale and standards that interconnection applications must meet;

(ii) A list of specific additional equipment that, if installed, will satisfy the requirement; and

(iii) A list of any inverter specifications and options that, if configured, will satisfy the requirement without the need for additional equipment.

(C) Relative distributed energy resource rating: This option requires the small generator facility's nameplate rating to be so small in comparison to its host facility's minimum load that the use of additional protective functions is not required to ensure that power will not be exported to the electric distribution system. This option requires the small generator facility's nameplate rating to be no greater than 50 percent of the interconnection customer's verifiable minimum host load during relevant hours over the past 12 months. This option is not available for interconnections to area networks or spot networks.

(b) Export control methods for limited export small generator facility.

(A) Directional Power Protection (Device 32): To limit export of power across the Point of Interconnection, a directional power protective function is implemented using a utility grade protective relay. The default setting for this protective function is the export capacity value, with a maximum 2.0 second time delay to limit Inadvertent export. When a project is located on a circuit using high-speed reclosing, the public utility may require a maximum delay of less than 2.0 seconds to safely facilitate the reclosing. To minimize the need for case-by-case design, which shall remain available, the utility handbook must provide:

(i) The rationale and standards that interconnection applications must meet;

(ii) A list of specific additional equipment that, if installed, will satisfy the requirement; and

(iii) A list of any inverter specifications and options that, if configured, will satisfy the requirement without the need for additional equipment.

(B) Configured power rating: A reduced output power rating utilizing the power rating configuration setting may be used to ensure the small generator facility does not generate power beyond a certain value lower than the nameplate rating. The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE Std 1547-2018, as described in subclause 10.4. A local small generator facility

communication interface is not required to utilize the configuration setting as long as it can be set by other means. The reduced power rating may be indicated by means of a nameplate rating replacement, a supplemental adhesive nameplate rating tag to indicate the reduced nameplate rating, or a signed attestation from the customer confirming the reduced capacity.

(c) Export control methods for non-exporting small generator facility or limited export small generator facility.

(A) Certified power control systems: Small generator facility may use certified power control systems to limit export. Small generator facility utilizing this option must use a power control system and inverter certified per UL 1741 by a NRTL with a maximum open loop response time of no more than 30 seconds to limit Inadvertent export. NRTL testing to the UL Power Control System Certification Requirement Decision must be accepted until similar test procedures for power control systems are included in a standard. This option is not available for interconnections to area networks or spot networks.

(B) Agreed-upon means: Small generator facility may be designed with other control systems and/or protective functions to limit export and inadvertent export if mutual agreement is reached with the Distribution Provider. The limits may be based on technical limitations of the interconnection customer's equipment or the electric distribution system equipment. To ensure inadvertent export remains within mutually agreed-upon limits, the interconnection customer may use an uncertified power control system, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the Distribution Provider.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
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860-082-0035
Cost Responsibility

(1) Study costs. Whenever a study is required under Tier 4 of the small generator interconnection rules, the applicant must pay the public utility for the reasonable costs incurred in performing the study. The public utility must base study costs on the scope of work determined and documented in the feasibility study agreement, the system impact study agreement, or the facilities study agreement, as applicable. The estimated

engineering costs used in calculating study costs must not exceed $100 per hour. A public utility may adjust the $100 hourly rate once in January of each year to account for inflation and deflation as measured by the Consumer Price Index. Before beginning a study, a public utility may require an applicant to pay a deposit of up to 50 percent of the estimated costs to perform the study or $1,000, whichever is less.

(2) Interconnection facilities. For interconnection review under Tier 4, a public utility must identify the interconnection facilities necessary to safely interconnect the small generator facility with the public utility's transmission or distribution system. The applicant must pay the reasonable costs of the interconnection facilities. The public utility constructs, owns, operates, and maintains the interconnection facilities.

(3) Interconnection equipment. An applicant or interconnection customer must pay all expenses associated with constructing, owning, operating, maintaining, repairing, and replacing its interconnection equipment. Interconnection equipment is constructed, owned, operated, and maintained by the applicant or interconnection customer.

(4) System upgrades. A public utility must design, procure, construct, install, and own any system upgrades to the public utility's transmission or distribution system necessitated by the interconnection of a small generator facility. A public utility must identify any adverse system impacts on an affected system caused by the interconnection of a small generator facility to the public utility's transmission or distribution system. The public utility must determine what actions or upgrades are required to mitigate these impacts. Such mitigation measures are considered system upgrades as defined in these rules. The applicant must pay the reasonable costs of any system upgrades.

(5) A public utility may not begin work on interconnection facilities or system upgrades before an applicant receives the public utility's good-faith, non-binding cost estimate and provides written notice to the public utility that the applicant accepts the estimate and agrees to pay the costs. A public utility may require an applicant to pay a deposit before beginning work on the interconnection facilities or system upgrades.

(a) If an applicant agrees to make progress payments on a schedule established by the applicant and the interconnecting public utility, then the public utility may require the applicant to pay a deposit of up to 25 percent of the estimated costs or $10,000, whichever is less. The public utility and the applicant must agree on progress billing, final billing, and payment schedules before the public utility begins work.

(b) If an applicant does not agree to make progress payments, then the public utility may require the applicant to pay a deposit of up to 100 percent of the estimated costs. If the actual costs are lower than the estimated costs, then the public utility must refund

the unused portion of the deposit to the applicant within 20 business days after the actual costs are determined.

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Statutes/Other Implemented: ORS 756.040 & ORS 756.060
History:
PUC 4-2024, amend filed 04/09/2024, effective 04/09/2024
PUC 10-2009, f. & cert. ef. 8-26-09

860-082-0040
Insurance

(1) A public utility may not require an applicant or an interconnection customer with a small generator facility with a nameplate rating of 200 kilowatts or less to obtain liability insurance in order to interconnect with the public utility's transmission or distribution system.

(2) A public utility may require an applicant or an interconnection customer with a small generator facility with a nameplate rating greater than 200 kilowatts to obtain prudent amounts of general liability insurance in order to interconnect to the public utility's transmission or distribution system.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
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860-082-0043
a. Each public utility will establish and maintain Communication Protocols and publish them in their handbooks.
b. Following execution of an interconnection agreement, the public utility and representatives of the applicant will meet once per month unless both parties mutually agree in writing to waive the meeting.
c. Representatives of the applicant are able to request meetings on a more frequent basis, such as weekly, as needed. The public utility will not decline requests without providing written justification.
d. Upon change of ownership of a small generator facility, either operating, or in the interconnection process, representative of the new owner(s) will provide written notice to the interconnecting utility within 15 business days of assuming ownership.

e. A public utility may charge an applicant reasonable costs associated with adhering to the public utility's communication protocols, and shall account for such cases separately from other costs.

860-082-0045
Tier 1 Interconnection Review

(1) A public utility must use the Tier 1 review procedures when an applicant submits an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility must have an export capacity not greater than 25 kilowatts, a nameplate rating not greater than 50 kilowatts, and use a UL 1741 certified inverter; and

(b) The small generator facility must not be interconnected to a transmission line or an area network.

(2) Tier 1 Approval Criteria. A public utility must approve an application for interconnection under the Tier 1 interconnection review procedures if the small generator facility meets the approval criteria in subsections (a) through (f). A public utility may not impose different or additional approval criteria.

(a) A Tier 1 small generator facility interconnection must use existing public utility facilities.

(b) Substation transformer backfeed screen. Where existing protective devices and equipment cannot adequately support backfeed, the aggregated export capacity on the substation transformer must be less than 80 percent of the relevant minimum load for the substation transformer.

(c) Penetration Screen for interconnection to a radial distribution circuit.

(A) If 12 months of minimum load data (including onsite load but not station service load served by the proposed small generator facility) are available for the line section, the aggregated export capacity on the line section is less than 90 percent of the relevant minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed small generator facility;

(B) If 12 months of minimum load data (including onsite load but not station service load served by the proposed small generator facility) are not available for the line section, the

aggregated export capacity on the circuit is less than 90 percent of the relevant minimum load for the feeder;

(C) If minimum load data are not available for the line section or the circuit, the aggregated export capacity on the circuit must not exceed 15 percent of the line section annual peak load as most recently measured at the substation or calculated for the line section.

(d) Network Screen. For interconnection of a small generator facility within a spot network, the aggregate nameplate rating may not exceed 20 percent of the spot network anticipated minimum load. The public utility may select any of the following methods to determine anticipated minimum load:

(A) The spot network's measured minimum load in the previous year, if available;

(B) Five percent of the spot network's maximum load in the previous year;

(C) The applicant's good faith estimate, if provided; or

(D) The public utility's good faith estimate if provided in writing to the applicant along with the reasons why the public utility considered the other methods to estimate minimum load inadequate.

(e) Single-Phase Shared Secondary Screen. For interconnection of a small generator facility to a single-phase shared secondary line, the aggregated export capacity on the shared secondary must not exceed 65 percent of the transformer nameplate power rating.

(f) Service Imbalance Screen. For interconnection of a single-phase small generator facility to the center tap neutral of a 240-volt service line, the addition of the small generator facility must not create a current imbalance between the two sides of the 240-volt service line of more than 20 percent of the nameplate power rating of the service transformer.

(3) In addition to the timelines and requirements in OAR 860-082-0025, the public utility must provide written notice to the applicant stating whether the small generator facility meets the Tier 1 approval criteria no later than 15 business days from the date a Tier 1 interconnection application is deemed complete. If a public utility does not notify an applicant whether the interconnection is approved or denied within 20 business days after the application is deemed complete, the interconnection will be deemed approved.

(4) Interconnection after passing screens. If the proposed interconnection passes the screens, the public utility must follow the requirements in OAR 860-082-0025(7)(f).

(5) Approval despite screen failure. Despite the failure of one or more screens, the public utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability. If the public utility determines that the small generator facility can be interconnected safely if minor modifications to the transmission or distribution system were made (for example, changing meters, fuses, or relay settings), then the public utility must offer the applicant a good-faith, non-binding estimate of the costs of such proposed minor modifications. Modifications are not considered minor under this section if the total cost of the modifications exceeds $10,000. If the applicant authorizes the public utility to proceed with the minor modifications and agrees to pay the entire cost of the modifications, then the public utility must approve the application.

(6) Process after screen failure. If the public utility cannot determine that the small generator facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, at the time the public utility notifies the applicant of the Tier 1 review results, the public utility must provide the applicant with:

(a) The screen results including specific information on the reason(s) for failure in writing using a standard format approved by the Commission; and

(b) An executable Supplemental Review Agreement.

(c) In addition, the public utility must allow the applicant to select one of the following, at the applicant's option. The applicant must notify the public utility of its selection within 10 business days, or the application will be deemed withdrawn.

(A) Request an applicant options meeting;

(B) Undergo supplemental review in accordance with OAR 860-082-0063; or

(C) Continue evaluating the application under Tier 4.

(7) Applicant options meeting. If the applicant requests an applicant options meeting, the public utility shall offer to convene a meeting at a mutually agreeable time within 15 business days of the applicant's request. At the applicant options meeting the public utility shall provide the applicant the opportunity to review the screen analysis and related results, to designate a different RPA, to review possible customers-generator modifications, and to discuss what further steps are needed to permit the small generator facility to connect safely and reliably.

(8) The interconnection process is not complete until:

(a) The witness test, if conducted by the public utility, is successful; and

(b) The applicant and public utility execute a certificate of completion. The certificate of completion must follow the standard form certificate developed by the public utility and approved by the Commission.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
History:
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860-082-0050
Tier 2 Interconnection Review

(1) A public utility must use the Tier 2 interconnection review procedures when an applicant submits an application requesting Tier 2 review to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for the Tier 1 interconnection review requirements;

(b) If the small generator facility is inverter-based, the small generator facility's export capacity does not exceed the limits identified in Table 1 attached, which vary according to the voltage of the line at the proposed point of interconnection;

(c) Inverter-based small generator facilities located within 2.5 line miles of a substation and on a main distribution line with minimum 600-amp capacity are eligible for Tier 2 interconnection under higher thresholds;

(d) If the small generator facility is not inverter-based, the small generator facility's export capacity is two megawatts or less;

(e) The small generator facility must not interconnect to a transmission line, or area network; and

(f) The small generator facility must use interconnection equipment that is either lab-tested equipment or field-tested equipment. For equipment to gain status as field-tested equipment, the applicant must provide all the documentation from the prior public utility approval including any interconnection studies and the certificate of completion.

(2) Tier 2 Approval Criteria. A public utility must approve an application to interconnect a small generator facility under the Tier 2 interconnection review procedures if the facility meets the approval criteria in subsections (a) through (l). A public utility may not impose different or additional approval criteria.

(a) Substation transformer backfeed screen. Where existing protective devices and equipment cannot adequately support backfeed, the aggregated export capacity on the substation transformer must be less than 80 percent of the relevant minimum load for the substation transformer.

(b) Penetration Screen for interconnection to a radial distribution circuit.

(A) If 12 months of minimum load data (including onsite load, but not station service load served by the proposed small generator facility) are available for the line section, the aggregated export capacity on the line section is less than 90 percent of the relevant minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed small generator facility;

(B) If 12 months of minimum load data (including onsite load but not station service load served by the proposed small generator facility) are not available for line section, the aggregated export capacity on the circuit is less than 90 percent of the relevant minimum load for the feeder;

(C) If minimum load data are not available for the line section or the circuit, the aggregated export capacity on the circuit must not exceed 15 percent of the line section annual peak load as most recently measured at the substation or calculated for the line section.

(c) Network Screen. For interconnection of a small generator facility within a spot network, the aggregate nameplate rating may not exceed 20 percent of the spot network’s anticipated relevant minimum load. The public utility may select any of the following methods to determine anticipated minimum load:

(A) The spot network’s measured minimum load in the previous year, if available;

(B) Five percent of the spot network’s maximum load in the previous year;

(C) The applicant’s good faith estimate, if provided; or

(D) The public utility’s good faith estimate if provided in writing to the applicant along with the reasons why the public utility considered the other methods to estimate minimum load inadequate.

(d) Fault Current Screen. The small generator facility, aggregated 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 primary voltage distribution line nearest the point of interconnection.

(e) Short-Circuit Interrupting Capability Screen. The aggregated nameplate rating on the distribution circuit must not cause any distribution protective devices and equipment (including substation breakers, fuse cutouts, and line reclosers) or other public utility equipment on the transmission or distribution system to be exposed to fault currents exceeding 90 percent of the short circuit interrupting capability. The small generator facility’s point of interconnection must not be located on a circuit that already exceeds 90 percent of the short circuit interrupting capability.

(f) Transient Stability Screen. The small generator facility’s nameplate rating, in aggregate with other small generator facilities interconnected to the distribution side of a substation transformer feeding the circuit where the small generator facility proposes to interconnect must not exceed 10 megawatts in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (for example, three or four distribution busses from the point of interconnection).

(g) Line Configuration Screen. Using Table 2 attached, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the project, including line configuration and the transformer connection to limit the potential for creating over-voltages on the interconnecting public utility's electric power system due to a loss of ground during the operating time of any anti-islanding function.

(h) Single-Phase Shared Secondary Screen. For interconnection of a small generator facility to a single-phase shared service line on the transmission or distribution system, the aggregated export capacity on the shared secondary must not exceed 65 percent of the transformer nameplate power rating.

(i) Service Imbalance Screen. For interconnection of a single-phase small generator facility to the center tap neutral of a 240-volt service line, the addition of the small generator facility must not create a current imbalance between the two sides of the 240-

volt service line of more than 20 percent of the nameplate power rating of the service transformer.

(j) Except as provided in section (4), the interconnection of the small generator facility must not require system upgrades or interconnection facilities different from or in addition to the applicant's proposed interconnection equipment.

(k) If the public utility's distribution circuit uses high speed reclosing with less than two seconds of interruption, then the small generator facility must not be a synchronous machine. If the small generator facility is a synchronous machine, then the applicant must submit a Tier 4 application.

(l) Inadvertent Export Screen. For interconnection of a proposed small generator facility that can introduce inadvertent export, where the nameplate rating minus the export capacity is greater than 250 kilowatts, the following inadvertent export screen is required. With a power change equal to the nameplate rating minus the export capacity, the change in voltage at the point on the medium voltage (primary) level nearest the point of interconnection does not exceed three percent. Voltage change will be estimated applying the formula shown in Figure 1 attached.

(3) Timelines. In addition to the timelines and requirements in OAR 860-082-0025 and if a net metering facility, OAR 860-039, within 20 business days after a public utility notifies an applicant that is application is complete, the public utility must:

(a) Evaluate the application using the Tier 2 approval criteria in section (2);

(b) Review any independent analysis of the proposed interconnection provided by the applicant that was performed using the Tier 2 approval criteria; and

(c) Provide written notice to the applicant stating whether the public utility approved the application. If the proposed interconnection passes the screens, the public utility must follow the requirements in OAR 860-082-0025(7)(f). If applicable, the public utility must include a comparison of its evaluation to the applicant's independent analysis.

(4) Approval despite screen failure. Despite the failure of one or more screens, the public utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability. If the public utility determines that the small generator facility could be interconnected safely if minor modifications to the transmission or distribution system were made (for example, changing meters, fuses, or relay settings), then the public utility must offer the applicant a good-faith, non-binding estimate of the costs of such proposed minor modifications. Modifications are not considered minor under this subsection if the total cost of the modifications exceeds

$10,000. If the applicant authorizes the public utility to proceed with the minor modifications and agrees to pay the entire cost of the modifications, then the public utility must approve the application.

(5) Process after screen failure. If the public utility cannot determine that the small generator facility may nevertheless be interconnected consistent with safety and reliability standards, at the time the public utility notifies the applicant of the Tier 2 review results, the public utility must provide the applicant with:

(a) The screen results, including specific information on the reason(s) for failure in writing, using a standard format approved by the Commission; and

(b) An executable Supplemental Review Agreement.

(c) In addition, the public utility must allow the applicant to select one of the following, at the applicant's option. The applicant must notify the public utility of its selection within 10 business days, or the application will be deemed withdrawn.

(A) Request an applicant options meeting;

(B) Undergo supplemental review in accordance with OAR 860-082-0063; or

(C) Continue evaluating the application under Tier 4.

(6) Applicant options meeting. If the applicant requests an applicant options meeting, the public utility shall offer to convene a meeting at a mutually agreeable time within 15 business days of the applicant's request. At the applicant options meeting the public utility shall provide the applicant the opportunity to review the screen analysis and related results, to designate a different RPA, to review possible customers-generator modifications, and to discuss what further steps are needed to permit the small generator facility to connect safely and reliably.

(7) The interconnection process is not complete until:

(a) The public utility approves the application;

(b) Any minor modifications to the transmission or distribution system required under section (4) are complete;

(c) The witness test, if conducted by the public utility, is successful; and

(d) The applicant and public utility execute a certificate of completion. The certificate of completion must follow the standard form certificate developed by the public utility and approved by the Commission.

[ED. NOTE: To view attachments referenced in rule text, click here to view rule.]

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
History:
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860-082-0055
Tier 3 Interconnection Review

(1) A public utility must use the Tier 3 interconnection review procedures when the applicant submits an application requesting Tier 3 review to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility must have a nameplate rating of 10 megawatts or less;

(b) The small generator facility must not be connected to a transmission line;

(c) The small generator facility must not export power beyond the point of interconnection; and

(d) The small generator facility must use low forward power relays or other protection functions that prevent power flow onto the area network.

(2) Tier 3 Approval Criteria. A public utility must approve an application to interconnect a small generator facility under the Tier 3 interconnection review procedures if the facility meets the Tier 2 approval criteria in OAR 860 082 0050(2)(a)-(b), (i) and the additional approval criteria in subsections (a), (b), or (c) of this section. A public utility may not impose different or additional approval criteria.

(a) For a small generator facility to interconnect to the load side of an area network distribution circuit, the small generator facility must meet the following criteria:

(A) The nameplate rating of the small generator facility must be 50 kilowatts or less;

(B) The small generator facility must use lab-tested, inverter-based interconnection equipment;

(C) The aggregated nameplate rating on the area network must not exceed five percent of an area network's maximum load or 50 kilowatts, whichever is less; and

(D) Except as allowed in subsection (2)(c), the interconnection of the small generator facility must not require system upgrades or interconnection facilities different from or in addition to the applicant’s proposed interconnection equipment.

(b) For a small generator facility to interconnect to a distribution circuit that is not networked, the small generator facility must meet the following criteria:

(A) The aggregated nameplate rating on the circuit must be 10 megawatts or less;

(B) The small generator facility’s point of interconnection must be to a radial distribution circuit;

(C) The small generator facility must not be served by a shared transformer;

(D) Except as allowed in subsection (2)(c), the interconnection of the small generator facility must not require system upgrades or interconnection facilities different from or in addition to the applicant’s proposed interconnection equipment; and

(E) If the public utility’s distribution circuit uses high speed reclosing with less than two seconds of interruption, then the small generator facility must not be a synchronous machine. If the small generator facility is a synchronous machine, then the applicant must submit a Tier 4 application.

(c) If the small generator facility fails to meet one or more of the Tier 3 approval requirements, but the public utility determines that the small generator facility could be interconnected safely if minor modifications to the transmission or distribution system were made (for example, changing meters, fuses, or relay settings), then the public utility must offer the applicant a good-faith, non-binding estimate of the costs of such proposed minor modifications. Modifications are not considered minor under this subsection if the total cost of the modifications exceeds $10,000. If the applicant authorizes the public utility to proceed with the minor modifications and agrees to pay the entire cost of the modifications, then the public utility must approve the application under Tier 3.

(3) In addition to the timelines and requirements in OAR 860-082-0025, the following timelines and requirements apply to Tier 3 interconnection reviews:

(a) An interconnecting public utility must schedule a scoping meeting within 10 business days after notifying an applicant that its application is complete. The applicant may agree to waive the scoping meeting requirement.

(b) Within 20 business days after a public utility notifies an applicant its application is complete or a scoping meeting is held, whichever is later, the public utility must:

(A) Evaluate the application using the Tier 3 approval criteria;

(B) Review any independent analysis of the proposed interconnection provided by the applicant that was performed using the Tier 3 approval criteria; and

(C) Provide written notice to the applicant stating whether the public utility approved the application. If the proposed interconnection passes the screens, the public utility must follow the requirements in OAR 860-082-0025(7)(f). If applicable, the public utility must include a comparison of its evaluation to the applicant's independent evaluation.

(4) Approval despite screen failure. Despite the failure of one or more screens, the public utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability.

(5) Process after screen failure. If the public utility cannot determine that the small generator facility may nevertheless be interconnected consistent with safety and reliability standards, at the time the public utility notifies the applicant of the Tier 3 review results, the public utility must provide the applicant with:

(a) The screen results, including specific information on the reason(s) for failure in writing using a standard format approved by the Commission; and

(b) An executable Supplemental Review Agreement.

(c) In addition, the public utility will allow the applicant to select one of the following, at the applicant's option:

(A) Request an applicant options meeting;

(B) Undergo supplemental review in accordance with OAR 860-082-0063; or

(C) Continue evaluating the application under Tier 4.

(d) The applicant must notify the public utility of its selection under subsection (c) within 10 business days, or the application will be deemed withdrawn.

(6) Applicant options meeting. If the applicant requests an applicant options meeting, the public utility shall offer to convene a meeting at a mutually agreeable time within 15 business days of the applicant's request. At the applicant options meeting the public utility shall provide the applicant the opportunity to review the screen analysis and related results, to designate a different RPA, to review possible customers-generator modifications, and to discuss what further steps are needed to permit the small generator facility to connect safely and reliably.

(7) The interconnection process is not complete until:

(a) The public utility approves the application;

(b) Any minor modifications to the transmission or distribution system required under subsection (2)(c) are complete;

(c) The witness test, if conducted by the public utility, is successful; and

(d) The applicant and public utility execute a certificate of completion. The certificate of completion must follow the standard form certificate developed by the public utility and approved by the Commission.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
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860-082-0060
Tier 4 Interconnection Review

(1) A public utility must use the Tier 4 interconnection review procedures when an applicant submits an application requesting Tier 4 review to interconnect a small generator facility meeting the following requirements:

(a) The small generator facility must have a nameplate rating of 10 megawatts or less.

(b) An applicant whose Tier 1, Tier 2, or Tier 3 application was denied may request that the public utility treat that existing application already in the public utility's possession as a new Tier 4 application. Within ten business days of receipt of the applicant's request

to use the existing application, the public utility will transfer the existing application to the Tier 4 process and notify the applicant whether or not the application is complete. If the application is incomplete, the public utility must provide a written list detailing all information that the applicant must provide to complete the application. The applicant will have ten business days after receipt of the list to submit the listed information. Otherwise, the application will be deemed withdrawn. The public utility must notify the applicant within ten business days of receipt of the revised application whether the revised application is complete or incomplete. The public utility may deem the application withdrawn if it remains incomplete.

(2) A public utility must approve an application to interconnect a small generator facility under the Tier 4 interconnection review procedures if the public utility determines that the safety and reliability of the public utility's transmission or distribution system will not be compromised by interconnecting the small generator facility. The applicant must pay the reasonable costs of any interconnection facilities or system upgrades necessitated by the interconnection.

(3) In addition to the timelines and requirements in OAR 860-082-0025, the timelines and requirements in sections (5) through (12) of this rule apply to Tier 4 interconnection reviews.

(4) A public utility and an applicant may agree to waive the requirement for a scoping meeting, the system impact study, or the facilities study. The applicant may waive the requirement for a feasibility study.

(5) A public utility must schedule a scoping meeting within 10 business days after notifying an applicant that its application is complete.

(a) The public utility and the applicant must bring to the scoping meeting all personnel, including system engineers, as may be reasonably required to accomplish the purpose of the meeting.

(b) The public utility and applicant must discuss whether the public utility should perform a feasibility study or proceed directly to a system impact study, a facilities study, or an interconnection agreement.

(c) If the public utility determines that no studies are necessary, then the public utility must follow the requirements in OAR 860-082-0025(7) if:

(A) The application meets the criteria in section (2); and

(B) The interconnection of the small generator facility does not require system upgrades or interconnection facilities different from or in addition to the applicant's proposed interconnection equipment.

(d) If the public utility determines that no studies are necessary and that the small generator facility could be interconnected safely if minor modifications to the transmission or distribution system were made (for example, changing meters, fuses, or relay settings), then the public utility must offer the applicant a good-faith, non-binding estimate of the costs of such proposed minor modifications. Modifications are not considered minor under this subsection if the total cost of the modifications exceeds $10,000. If the applicant authorizes the public utility to proceed with the minor modifications and agrees to pay the entire cost of the modifications, then the public utility must send the applicant an executed interconnection agreement within 15 business days of receipt of the applicant's agreement to pay for the minor modifications.

(6) If the applicant requests a feasibility study, then the public utility must provide the applicant with an executable feasibility study agreement within five business days of the date of the scoping meeting.

(a) The feasibility study agreement must include a detailed scope for the feasibility study, a reasonable schedule for completion of the study, and a good-faith, non-binding estimate of the costs to perform the study.

(b) The feasibility study agreement must follow the standard form agreement developed by the public utility and approved by the Commission.

(c) The applicant must execute the feasibility study agreement within 15 business days of receipt of the agreement or the application is deemed withdrawn.

(d) The public utility must make reasonable, good-faith efforts to follow the schedule set forth in the feasibility study agreement for completion of the study.

(e) The feasibility study must identify any potential adverse system impacts on the public utility's transmission or distribution system or an affected system that may result from the interconnection of the small generator facility. In determining possible adverse system impacts, the public utility must consider the aggregated nameplate rating or export capacity when applicable of all generating facilities that, on the date the feasibility study begins, are directly interconnected to the public utility's transmission or distribution system, have a pending completed application to interconnect with a higher queue position, or have an executed interconnection agreement with the public utility.

(f) The public utility must evaluate multiple potential points of interconnection at the applicant's request. The applicant must pay the costs of this additional evaluation.

(g) The public utility must provide a copy of the feasibility study to the applicant within five business days of the study's completion.

(h) If the feasibility study identifies any potential adverse system impacts, then the public utility must perform a system impact study.

(i) If the feasibility study does not identify any adverse system impacts, then the public utility must perform a facilities study if the public utility reasonably concludes that a facilities study is necessary to adequately evaluate the application.

(A) If the public utility concludes that a facilities study is not required, then the public utility must approve the application if the application meets the criteria in section (2) and the interconnection of the small generator facility does not require system upgrades or interconnection facilities different from or in addition to the applicant's proposed interconnection equipment.

(B) If the public utility concludes that a facilities study is not required and that the small generator facility could be interconnected safely if minor modifications to the transmission or distribution system were made (for example, changing meters, fuses, or relay settings), then the public utility must offer the applicant a good-faith, non-binding estimate of the costs of such proposed minor modifications. Modifications are not considered minor under this paragraph if the total cost of the modifications exceeds $10,000. If the applicant authorizes the public utility to proceed with the minor modifications and agrees to pay the entire cost of the modifications, then the public utility must approve the application.

(7) If a public utility is required to perform a system impact study under subsection (6)(h), or if an applicant and a public utility agree in the scoping meeting to waive the feasibility study and proceed directly to the system impact study, then the public utility must provide the applicant with an executable system impact study agreement within five business days of completing the feasibility study or from the date of the scoping meeting, whichever is applicable.

(a) The system impact study agreement must include a detailed scope for the system impact study, an option to select to be studied for Limited Operations, a reasonable schedule for completion of the study, and a good-faith, non-binding estimate of the costs to perform the study.

(b) The system impact study agreement must follow the standard form agreement developed by the public utility and approved by the Commission.

(c) Within 15 business days of receipt of the system impact study agreement ~~T~~the applicant must execute and return the system impact study agreement or submit a notice of intent to use a third-party consultant to conduct the system impact study, or the application is deemed withdrawn.

(d) The public utility must make reasonable, good-faith efforts to follow the schedule set forth in the system impact study agreement for completion of the study.

(e) The system impact study must identify and detail the impacts on the public utility's transmission or distribution system or on an affected system that would result from the interconnection of the small generator facility if no modifications to the small generator facility or system upgrades were made. The system impact study must include evaluation of the adverse system impacts identified in the feasibility study and in the scoping meeting.

(f) In determining possible adverse system impacts, the public utility must consider the aggregated nameplate rating, or export capacity when applicable, of all generating facilities that, on the date the system impact study begins, are directly interconnected to the public utility's transmission or distribution system, have a pending completed application to interconnect with a higher queue position, or have an executed interconnection agreement with the public utility. If the small generator facility limits export pursuant to OAR 860-082-0033, the system impact study must use export capacity instead of the nameplate rating, except when assessing fault current contribution. To assess fault current contribution, the system impact study must use the rated fault current if the customer provides the relevant information or provide a written explanation for cases where the utility does not want to rely on customer-provided data. An example of customer-provided data would include provision of manufacturer test data (pursuant to the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the nameplate rating. The public utility must provide an explanation for any cases where the utility does not want to rely on customer-provided data.

(g) The system impact study must include:

(A) A short circuit analysis;

(B) A stability analysis;

(C) A power flow analysis;

(D) Voltage drop and flicker studies;

(E) Protection and set point coordination studies;

(F) Grounding reviews;

(G) The underlying assumptions of the study;

(H) The results of the analyses; and

(I) Any potential impediments to providing the requested interconnection service.

(h) If an applicant provides an independent system impact study to the public utility, then the public utility must evaluate and address any alternative findings from that study.

(i) The public utility must provide a copy of the system impact study to the applicant within five business days of completing the study.

(j) If a public utility determines in a system impact study that interconnection facilities or system upgrades are necessary to safely interconnect a small generator facility, then the public utility must perform a facilities study.

(k) If the public utility determines that no interconnection facilities or system upgrades are required, and the public utility concludes that the application meets the criteria in section (2), then the public utility must approve the application with 15 business days of completion of the system impact study.

(l) If the public utility determines that no interconnection facilities or system upgrades are required and that the small generator facility could be interconnected safely if minor modifications to the transmission or distribution system were made (for example, changing meters, fuses, or relay settings), then the public utility must offer the applicant a good-faith, non-binding estimate of the costs of such proposed minor modifications. Modifications are not considered minor under this subsection if the total cost of the modifications exceeds $10,000. If the applicant authorizes the public utility to proceed with the minor modifications and agrees to pay the entire cost of the modifications, then the public utility must approve the application within 15 business days of the applicant’s agreement to pay for the minor modifications.

(m) The public utility must allow opportunity for an applicant in any serially studied small generator interconnection queue to use a third-party consultant to conduct the system impact study.

(A) The public utility must publish criteria for applicants electing to use a third-system impact study including minimum requirements for the study format and methods, the data sharing process, any non-disclosure and data handling agreements, and other needed policies. The criteria must also include:

(i) A description of necessary analysis, as well as required format for output, including any necessary workpapers,

(ii) A listing of national standards relied on by the public utility, and

(iii) A listing of any additional critical standards required, with underlying rationale.

(B) Each public utility must designate and make available a liaison for applicants electing to use a third-party consultant to clarify data, resolve ambiguities, and explain technical requirements to the best of the liaison's ability. Information provided by the liaison will not replace or limit the utility's review of the third-party consultant's study under subsection (7)(o).

(C) Each public utility must establish detailed instructions for eligible interconnection applicants to:

(i) Provide a qualifying notice of intent to use a third-party consultant to conduct the system impact study, including any forms required for non-disclosure and data handling agreements; and

(ii) Request the data necessary to perform to the third-party system impact study to the public utility's specifications.

(D) Within five (5) business days of receipt of an applicant's notice of intent to use a third-party consultant to perform the system interconnection study, the public utility will notify the applicant in writing whether or not the application is complete.

(E) The public utility must provide a third-party consultant access to public utility data within 21 calendar days of the public utility's receipt of a qualifying notice of intent to use a third-party consultant to conduct a system impact study. Data provided by the

public utility must be provided in a standardized, machine-readable format, except as otherwise agreed.

(n) Applicant obligations for third-party studies.

(A) Before submitting a third-party study, the applicant must notify the public utility of their intent to use a third-party consultant for the system impact study in the manner set forth by the public utility under subsection (7)(m)(C).

(B) Any third-party system impact study must be completed within 45 business days of the later of the following, unless another date is mutually agreed to:

(i) The public utility's written acceptance of applicant's notice of intent to use of third-party consultant to perform system impact study, or

(ii) The applicant's receipt of data required under this rule.

(C) Any third-party study must include a professional engineer's stamp.

(o) The public utility must accept or reject in writing any third-party study within 30 business days of study receipt.

(A) If a third-party study is accepted, the public utility must follow the process set forth in subsection (7)(j), (k), or (l).

(B) If a study is rejected, the public utility must identify all study modifications required, with supporting rationale.

(C) If a study is rejected, the applicant has 45 business days to provide an updated study addressing all public utility-raised issues.

(D) A public utility's decision to approve or reject a third-party study must be based on safety, reliability and compliance with published standards.

(E) The public utility may charge the applicant for the reasonable costs incurred by the public utility in preparing and providing technical data under this subsection.

(F) The public utility may charge the applicant for the reasonable costs of reviewing any third-party study up to $1,000.

(8) If a public utility is required to perform a facilities study under subsection (6)(i) or 7(j), or if an applicant and a public utility agree in the scoping meeting to waive the system impact study and proceed directly to the facilities study, then the public utility must

provide the applicant with an executable facilities study agreement within five business days of completing the system impact study or within five business days from the date of the scoping meeting, whichever is applicable.

(a) The facilities study agreement must include a detailed scope for the facilities study, an option to include a site visit to inform the study, a reasonable schedule for completion of the study, and a good-faith, non-binding estimate of the costs to perform the study.

(b) The facilities study agreement must follow the standard form agreement developed by the public utility and approved by the Commission.

(c) The applicant must execute the interconnection facilities study agreement within 15 business days after receipt of the agreement or the application is deemed withdrawn.

(d) The public utility must make reasonable, good-faith efforts to follow the schedule set forth in the facilities study agreement for completion of the study.

(e) The facilities study must identify the interconnection facilities and system upgrades required to safely interconnect the small generator facility and must determine the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs. Design for any required interconnection facilities or system upgrades must be performed under the facilities study agreement. The public utility must also identify the electrical switching configuration of the equipment, including transformer, switchgear, meters, and other station equipment.

(f) The public utility may contract with a third-party consultant to complete the interconnection facilities and system upgrades identified in the facilities study. A public utility and an applicant may agree in writing to allow the applicant to hire a third-party consultant to complete the interconnection facilities and system upgrades, subject to public utility oversight and approval.

(g) The interconnection facilities study must include a detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

(h) If the applicant agrees to pay for the interconnection facilities and system upgrades identified in the facilities study, then the public utility must approve the application.

(9) The public utility may contract with a third-party consultant to complete a feasibility study, system impact study, or facilities study. A public utility and an applicant may agree in writing to allow the applicant to hire a third-party consultant to complete a

feasibility study, system impact study, or facilities study, subject to public utility oversight and approval.

(10) The interconnection process is not complete until:

(a) The public utility approves the application;

(b) Any interconnection facilities or system upgrades have been completed;

(c) Any minor modifications to the public utility's transmission or distribution system required under subsections (5)(d), 6(i)(B), or (7)(l) have been completed;

(d) The witness test, if conducted by the public utility, is successful; and

(e) The applicant and public utility execute a certificate of completion.

(11) If a small generator facility is not approved under the Tier 4 interconnection review procedures, then the public utility must provide a written explanation of the denial to the applicant.

(12) Interconnection Study Timelines.
(a) Notwithstanding other subsections in this rule regarding timing of studies, the following timelines are applicable to serially studied small generators.
(A) The public utility must perform a system impact study within 45 business days of the latest of the following:
(i) The public utility's receipt of a signed system impact study agreement from the applicant;
(ii) The public utility's receipt of all necessary study fees and deposits from the applicant; and
(iii) The public utility's receipt of all necessary data from applicant.
(iv) The study timeline may be extended by 10 business days when an applicant requests the system impact study incorporate a limited operations analysis.
(B) The public utility must perform a facilities study within 45 business days of the latest of the following
(i) The public utility's receipt of a signed facilities study agreement from the applicant;
(ii) The public utility's receipt of all necessary study fees and deposits from the applicant; and
(iii) The public utility's receipt of all necessary data from the applicant.
(C) At request of the public utility, the time to complete the facilities study under subsection 12(a)(B) can be extended for an additional 45 business day period when the applicant requests a site visit occur during the facilities study.

(D) Upon request of the applicant, the time to complete the system impact study or facilities study under subsections 12(a) (A) and (B) may be extended beyond the end of the 45 business day period, or any longer period established under subsection 12(a)(C), if the delay will not impact lower queued projects.

(b) For any study that is not provided in the timeline specified in section (12)the public utility:

(A) Must reduce the study costs owed to the public utility from the applicant by fifty percent for any delay up to 15 business days from the due date for the study, and by 100 percent for any delay longer than 15 business days, refund any study costs in excess of the reduced study fees if the applicant has already remitted payment to public utility, and file a report with the Commission indicating the reason for failure to meet the time requirement and the amount of time required to complete the study; or

(B) May seek a waiver from the Commission under OAR 860-082-0020 of the obligation to finish the study within 45 days, for good cause.

(13) Construction timelines.

(a) This subsection applies to all serially studied small generators proposing to interconnect to a public utility's system.

(b) The construction timeline included in the Interconnection Agreement, starting at the execution of the Interconnection Agreement through the witness test, must be no longer than 600 calendar days unless otherwise agreed to by applicant and the public utility.

(A) Prior to execution of the Interconnection Agreement, a public utility may seek waiver of the maximum 600-day construction timeline from the Commission for good cause if parties cannot reach agreement on the construction timeline.

(B) After execution of the Interconnection Agreement, the 600-day timeline may be extended by mutual agreement when an applicant misses a milestone specified in the interconnection agreement. Prior to terminating an interconnection agreement due to a missed milestone(s), the public utility must offer to update the interconnection agreement to incorporate day-for-day extension for missed milestones.

(c) A public utility that fails to construct the facilities specified in the Interconnection Agreement within the 600 day maximum timeline, or date specified in the Interconnection Agreement if later, will discount the costs charged to the applicant for interconnection, including costs of facilities by five (5) percent for every 30 calendar days construction extends beyond the maximum 600-day timeline or agreed upon end of construction timelines, if later than 600 days, unless:

(A) Following completion of the construction of the required facilities, the public utility obtains a waiver from the Commission under OAR 860-0082-0010 of the obligation to construct facilities within the maximum 600 day timeline, or by the date

specified in the Interconnection Agreement if later, for good cause, which could include events outside of the public utility control.

(B) The public utility and applicant agree in writing to extend the construction timeline included in the Interconnection Agreement.

(d) An applicant may assume responsibility for design, procurement, and construction of mutually agreed-upon interconnection facilities and stand-alone system upgrades, to be consistent with Commission-approved terms and conditions for the option to build in the QF-LGIA (see Order No. 25-355);

(A) The applicant and public utility must execute an agreement documenting the interconnection facilities and stand-alone system upgrades that will be made by the applicant.

(14) Other Interconnection Options; Limited Operation.

(a) After execution of an Interconnection Agreement and pending completion of required interconnection facilities or system upgrades necessary to accommodate operation at the facility's full authorized export capacity, the applicant may seek authority from the public utility for limited operations.

(b) The public utility shall, upon the request and at the expense of applicant that has executed a system impact study, perform operating studies on a timely basis to determine the extent to which the applicant's interconnection facilities may operate prior to the completion of system upgrades consistent with applicable laws and regulations and reliability standards.

(c) An applicant may only engage in limited operations with the public utility's express written authorization, which allows operation pursuant to fixed limited export parameters or other utility-approved operating limitations consistent with the interconnection agreement and applicable utility requirements.

(d) A public utility shall not unreasonably deny an applicant authority to engage in limited operations pending completion of required facilities.

(e) Any costs the public utility incurs under this subsection are not subject to discount as provided in subsection 13(c).

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
History:
PUC 4-2026, temporary amend filed 04/01/2026, effective 04/01/2026 through 09/04/2026
PUC 4-2024, amend filed 04/09/2024, effective 04/09/2024
PUC 10-2009, f. & cert. ef. 8-26-09

860-082-0063
Supplemental Review

(1) To accept the offer of a supplemental review, the applicant must submit a signed copy of the Supplemental Review Agreement and pay a supplemental review fee of $1,000, both within 10 business days of the offer. If the written agreement and fee have not been received within that timeframe, the Application will be deemed withdrawn unless the applicant has notified the public utility that they wish to continue being evaluated under the Tier 4 review procedures.

(2) Within 20 business days of an applicant's election to undergo supplemental review, the public utility must perform supplemental review using the screens set forth below, notify the applicant of the results, and include with the notification a written report of the analysis and data underlying the public utility's determinations under the screens.

(a) Supplemental Review Penetration Screen: Where 12 months of line section minimum load data (including onsite load, but not station service load served by the proposed small generator facility) are available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate export capacity on the feeder or line section is less than 100 percent of the relevant minimum load on the feeder. If minimum load data are not available, or cannot be calculated, estimated, or determined, the aggregated export capacity on the line section is less than 30 percent of the peak load for all line Sections bounded by automatic sectionalizing devices upstream of the proposed project.

(A) Load that is co-located with load-following, non-exporting, or export-limited projects should be appropriately accounted for. The public utility may take the impacts of non-export or export limited generation on the calculation of daytime minimum load when evaluating potential system impacts.

(B) The interconnecting public utility will not consider as part of the aggregate export capacity for purposes of this screen the export capacity of generators known to be already reflected in the minimum load data, including combined heat and power (CHP) facility capacity.

(b) Voltage and Power Quality Screen. In aggregate with existing generation on the line section:

(A) The voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions;

(B) The voltage fluctuation is within acceptable limits as defined by IEEE Std 1547™;

(C) The harmonic levels meet IEEE 1547 limits at the Point of Interconnection; and

(D) Substation transformer backfeed screen. Where existing protective devices and equipment cannot adequately support backfeed, the aggregated export capacity on the substation transformer must be less than 80 percent of the relevant minimum load for the substation transformer.

(E) Supplemental Grounding Screen: If the project failed the Line Configuration Screen, apply the Supplemental Grounding Screen in paragraphs (F)-(H). If the project limits export pursuant to OAR 860-082-0033, the export capacity must be included in any analysis including power flow simulations.

(F) For projects with a rotating machine, if effective grounding is maintained, the project passes the screen.

(G) For projects with a three-phase inverter, apply one of the following screens:

(i) If the line-to-neutral connected load on the feeder or line section is greater than 33 percent of peak load on the feeder or line-section, the project passes the screen.

(ii) If using a supplemental grounding software tool:

(I) If the tool determines that supplemental grounding is not required to maintain effective grounding, the project passes this screen.

(II) If the tool determines that supplemental grounding is required, the applicant must agree to modify the project to include supplemental grounding. If the applicant does not agree to modify the project, the project fails this screen.

(H) If using detailed hosting capacity analysis that incorporates evaluation of temporary overvoltage risk for inverters, the project passes the screen if the nameplate rating of the project is below the available hosting capacity at the Point of Interconnection.

(c) Safety and Reliability Screen. The location of the proposed small generator facility and the aggregate export capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the study process. If the project limits export pursuant to OAR 860-082-0033, the export capacity must be included in any analysis, including power flow simulations, except when assessing fault current contribution. To assess fault current contribution, the analysis must use the rated fault current; for example, the applicant may provide manufacturer test data (pursuant to the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the nameplate rating. The interconnecting public utility may consider the following factors and others in determining potential impacts to safety and reliability in applying this screen:

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

(B) Whether the loading along the line section is uniform or even.

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

(D) Whether the project incorporates an adjustable time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

(E) Whether operational flexibility is reduced by the project, such that transfer of the line section(s) of the Project to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

(F) Whether the project employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

(3) If the proposed interconnection passes the supplemental screens, the Application must be approved, and the public utility will provide the applicant an executed Interconnection Agreement pursuant to the procedure set forth in OAR 860-082-0025(7)(e).

(4) After receiving an Interconnection Agreement executed by the public utility, the applicant must proceed under the terms of the applicable level of review under which the Application was initially studied.

(5) Applicants undergoing Supplemental Review will be able to access, review, and verify minimum load calculations except in cases where the minimum load data contain identifiable individual customer data.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
History:
PUC 4-2024, adopt filed 04/09/2024, effective 04/09/2024

860-082-0065
Recordkeeping and Reporting Requirements

(1) The public utility must maintain a record of the following information for at least two years:

(a) The number of complete small generator interconnection applications received;

(b) The time required to complete the review process for each application; and

(c) The reasons for the approval or denial of each application.

(2) For as long as an interconnection customer's small generator facility is interconnected to a public utility's transmission or distribution system, the interconnecting public utility must maintain copies of the interconnection application, interconnection agreement, and certificate of completion for the small generator facility. The public utility must provide a copy of the interconnection customer's records to the interconnection customer within 15 business days after receipt of a written request.

(3) The public utility must submit ~~an annual~~ quarterly reports to the Commission summarizing the public utility's interconnection activities for the previous calendar ~~year~~quarter. The ~~annual~~ quarterly reports must be filed by February 28, May 30, August 31, and November 30 and must include the following information for each interconnection application that was active during the quarter:

(a) Summary statistics including:
(A)The number of complete small generator interconnection applications received;

(~~b~~B) The number of small generator facility interconnections completed;

(~~c~~C) The number of applications withdrawn;~~The types of small generator facilities applying for interconnection and the nameplate rating of the facilities;~~

~~(d) The location of completed and proposed small generator facilities by zip code;~~

(~~e~~D) For each Tier 3 and Tier 4 small generator interconnection approval, the basic telemetry configuration, if applicable; and

(b) Data as required in any report using the Excel template as approved by the Commission
(c) Any reports will be evaluated every three years for continued applicability.
~~(f) For each Tier 4 small generator interconnection approval:~~

~~(A) The interconnection facilities required to accommodate the interconnection of a small generator facility and the estimated costs of those facilities; and~~

~~(B) The system upgrades required to accommodate the interconnection of a small generator facility and the estimated costs of those upgrades.~~

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
History:
PUC 4-2024, amend filed 04/09/2024, effective 04/09/2024
PUC 10-2009, f. & cert. ef. 8-26-09

860-082-0070
Metering and Monitoring

(1) The public utility must install, maintain, test, repair, operate, and replace any metering and data acquisition equipment necessary under the terms of the public utility's interconnection agreement, power purchase agreement, or power service agreement with an applicant or interconnection customer. The applicant or interconnection customer is responsible for all reasonable costs associated with the metering and data acquisition equipment. The public utility and the applicant or interconnection customer must have unrestricted access to such equipment as necessary to conduct routine business or respond to an emergency.

(2) Except as provided in subsection 3(b), a public utility may not require an applicant or interconnection customer with a small generator facility with a nameplate rating of less than three megawatts to provide or pay for the data acquisition or telemetry equipment necessary to allow the public utility to remotely monitor the small generator facility's electric output.

(3) At its discretion, a public utility may require an applicant or interconnection customer to pay for the purchase, installation, operation, and maintenance of the data acquisition or telemetry equipment necessary to allow the public utility to remotely monitor the small generator facility's electric output if:

(a) The small generator facility has a nameplate rating greater than or equal to 3 megawatts; or

(b) The small generator facility meets the criteria in OAR 860-082-0055(1) for Tier 3 interconnection review and the aggregated nameplate rating on the circuit exceeds 50 percent of the line section annual peak load.

(4) A public utility and an applicant or interconnection customer may agree to waive or modify the telemetry requirements in this rule.

(5) Telemetry Requirements.

(a) The communication must take place via a private network link using a frame relay, fractional T-1 line, or other suitable device. Dedicated remote terminal units from the interconnected small generator facility to a public utility's substation and energy management system are not required.

(b) A single communication circuit from the small generator facility to the public utility is sufficient.

(c) Communications protocol must be DNP 3.0 or another reasonable standard used by the public utility.

(d) The small generator facility must be capable of sending telemetric monitoring data to the public utility at a minimum rate of every two seconds from the output of the small generator facility's telemetry equipment to the public utility's energy management system.

(e) A small generator facility must provide the following minimum data to the public utility:

(A) Net real power flowing out or into the small generator facility (analog);

(B) Net reactive power flowing out or into the small generator facility (analog);

(C) Bus bar voltage at the point of common coupling (analog);

(D) Data processing gateway heartbeat (used to certify the telemetric signal quality); and

(E) On-line or off-line status (digital).

(f) If an applicant or interconnection customer operates the equipment associated with the high voltage switchyard interconnecting the small generator facility to the transmission or distribution system and is required to provide monitoring and telemetry, then the interconnection customer must provide the following data to the public utility in addition to the data in section (e):

(A) Switchyard line and transformer megawatt and mega volt ampere reactive values;

(B) Switchyard bus voltage; and

(C) Switching device status.

Statutory/Other Authority: ORS 183, ORS 756 & ORS 757
Statutes/Other Implemented: ORS 756.040 & ORS 756.060
History:
PUC 4-2024, amend filed 04/09/2024, effective 04/09/2024
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860-082-0075
Temporary Disconnection

(1) Under emergency conditions, a public utility or an interconnection customer may suspend interconnection service and temporarily disconnect a small generator facility from the public utility's transmission or distribution system at any time and for as long as reasonably necessary.

(a) A public utility must notify an interconnection customer immediately after becoming aware of an emergency condition that may reasonably be expected to affect a small generator facility's operation. To the extent possible, the notice must describe the emergency condition, the extent of the damage or deficiency, the expected effect on the small generator facility, the anticipated duration of the condition, and the necessary corrective action.

(b) An interconnection customer must notify the public utility immediately after becoming aware of an emergency condition that may reasonably be expected to affect the public utility's transmission or distribution system. To the extent possible, the notice must describe the emergency condition, the extent of the damage or deficiency, the expected effect on the public utility's transmission or distribution system, the anticipated duration of the condition, and the necessary corrective action.

(2) A public utility or an interconnection customer may suspend interconnection service and temporarily disconnect a small generator facility to perform routine maintenance, construction, or repairs. A public utility or an interconnection customer must provide written notice five business days before suspending interconnection service or temporarily disconnecting the small generator facility. A public utility and an interconnection customer must use reasonable efforts to coordinate interruptions caused by routine maintenance, construction, or repairs.

(3) A public utility must use reasonable efforts to provide written notice to an interconnection customer affected by a forced outage of the public utility's transmission or distribution system at least five business days before the forced outage. If prior written notice is not given, then the public utility must provide the interconnection customer written documentation explaining the circumstances of the disconnection within five business days after the forced outage.

(4) A public utility may disconnect a small generator facility if the public utility determines that operation of the small generator facility will likely cause disruption or deterioration of service to other customers served by the public utility's transmission or distribution system, or if the public utility determines that operation of the small generator facility could cause damage to the public utility's transmission or distribution system.

(a) The public utility must provide written notice to the interconnection customer of the disconnection at least five business days before the disconnection. If the condition requiring disconnection can be remedied, then the public utility must describe the remedial action necessary.

(b) If requested by the interconnection customer, the public utility must provide documentation supporting the public utility's decision to disconnect.

(c) The public utility may disconnect the small generator facility if the interconnection customer fails to perform the remedial action identified in the notice of disconnection within a reasonable time, but no less than five business days after the interconnection customer received the notice of disconnection.

(5) A public utility may temporarily disconnect a small generator facility if an interconnection customer makes any change to the facility, other than a minor equipment modification, without the public utility's prior written authorization. The public utility may disconnect the small generator facility for the time necessary for the public utility to evaluate the affect of the change to the small generator facility on the public utility's transmission or distribution system.

(6) A public utility has the right to inspect an interconnection customer's small generator facility at reasonable hours and with reasonable prior written notice to the interconnection customer. If the public utility discovers that the small generator facility is not in compliance with the requirements of the small generator interconnection rules, then the public utility may require the interconnection customer to disconnect the small generator facility until compliance is achieved.

Statutory/Other Authority: ORS 183 & 756

Statutes/Other Implemented: ORS 756.040 & 756.060
History:
PUC 10-2009, f. & cert. ef. 8-26-09

860-082-0080
Arbitration of Disputes

(1) An interconnecting public utility or an interconnection applicant may petition the Commission for arbitration of disputes arising during review of an application to interconnect a small generator facility or during negotiation of an interconnection agreement. If the public utility or the applicant petitions the Commission to arbitrate their dispute, then the Commission will use an administrative law judge (ALJ) as arbitrator unless workload constraints necessitate the use of an outside arbitrator.

(2) A petition for arbitration of an interconnection agreement must contain:

(a) A statement of all unresolved issues;

(b) A description of each party's position on the unresolved issues; and

(c) A proposed agreement addressing all issues, including those on which the parties have reached agreement and those that are in dispute.

(3) A petition for arbitration of a dispute arising during review of an application to interconnect a small generator facility must contain:

(a) A statement of all unresolved issues;

(b) A description of each party's position on the unresolved issues; and

(c) A proposed resolution for each unresolved issue.

(4) Respondent may file a response within 25 calendar days of the petition for arbitration. In the response, the respondent must address each issue listed in the petition, describe the respondent's position on those issues, and present any additional issues for which the respondent seeks resolution.

(5) The filing of a petition for arbitration of a dispute arising during review of an application to interconnect a small generator facility does not affect the application’s queue position.

(6) The arbitration is conducted in a manner similar to a contested case proceeding, and the arbitrator has the same authority to conduct the arbitration process as an ALJ has in conducting hearings under the Commission's rules, but the arbitration process is streamlined. The arbitrator holds an early conference to discuss processing of the case. The arbitrator establishes the schedule and decides whether an oral hearing is necessary. After the oral hearing or other procedures (for example, rounds of comments), each party submits its final proposed interconnection agreement or resolution of disputed issues. The arbitrator chooses between the two final offers. If neither offer is consistent with applicable statutes, Commission rules, and Commission policies, then the arbitrator will make a decision that meets those requirements.

(7) The arbitrator may allow formal discovery only to the extent deemed necessary. Parties are required to make good faith attempts to exchange information relevant to any disputed issue in an informal, voluntary, and prompt manner. Unresolved discovery disputes are resolved by the arbitrator upon request of a party. The arbitrator will order a party to provide information if the arbitrator determines the requesting party has a reasonable need for the requested information and that the request is not overly burdensome.

(8) Only the two negotiating parties have full party status. The arbitrator may confer with Commission staff for assistance throughout the arbitration process.

(9) To keep the process moving forward, appeals to the Commission are not allowed during the arbitration process. An arbitrator may certify a question to the Commission if the arbitrator believes it is necessary.

(10) To accommodate the need for flexibility, the arbitrator may use different procedures so long as the procedures are fair, treat the parties equitably, and substantially comply with the procedures listed here.

(11) The arbitrator must serve the arbitration decision on the interconnecting public utility and the interconnection applicant. The parties may file comments on the arbitration decision with the Commission within 10 calendar days after service.

(12) The Commission must accept, reject, or modify an arbitration decision within 30 calendar days after service of the decision.

(13) Within 14 calendar days after the Commission issues an order on a petition for arbitration of an interconnection agreement, the petitioner must prepare an interconnection agreement complying with the terms of the decision and serve it on respondent. Respondent must either sign and file the interconnection agreement or file objections to it within 10 calendar days of service of the agreement. If objections are

filed, respondent must state how the interconnection agreement fails to comply with the Commission order and offer substitute language complying with the decision. The Commission must approve or reject a filed interconnection agreement within 20 calendar days of its filing or the agreement is deemed approved.

(14) If petitioner, without respondent's consent, fails to timely prepare and serve an interconnection agreement on respondent, respondent may file a motion requesting the Commission dismiss the petition for arbitration with prejudice. The Commission may grant such motion if the petitioner's failure to timely prepare and serve the interconnection agreement was the result of inexcusable neglect on the part of petitioner.

(15) The public utility and the applicant may agree to hire an outside arbitrator rather than file a petition with the Commission. The public utility and the applicant must share equally the costs of an outside arbitrator unless they mutually agree to a different payment arrangement.

Statutory/Other Authority: ORS 756
Statutes/Other Implemented: ORS 756.040 & 756.500
History:
PUC 10-2009, f. & cert. ef. 8-26-09

860-082-0085
Complaints for Enforcement

(1) This rule specifies the procedure for a public utility, an interconnection customer, or an applicant to file a complaint for the enforcement of an interconnection agreement. Filing dates for enforcement complaint proceedings are calculated and enforced per OAR 860-001-0150.

(2) At least 10 days prior to filing a complaint for enforcement, complainant must give written notice to defendant and the Commission that complainant intends to file a complaint for enforcement. The notice must identify the provisions in the agreement that complainant alleges were or are being violated and the specific acts or failure to act that caused or are causing the violation, and whether complainant anticipates requesting temporary or injunctive relief. On the same day the notice is filed with the Commission, complainant must serve a copy of the notice on defendant’s authorized representative, attorney of record, or designated agent for service of process. Complainant must also serve the notice on all persons designated in the interconnection agreement to receive notices;

(3) A complaint for enforcement must:

(a) Contain a statement of specific facts demonstrating that the complainant conferred with defendant in good faith to resolve the dispute, and that despite those efforts the parties failed to resolve the dispute;

(b) Include a copy of the written notice, required by section (2), indicating that the complainant intends to file a complaint for enforcement;

(c) Include a copy of the interconnection agreement or the portion of the agreement that the complainant contends that defendant violated or is violating. If a copy of the entire agreement is provided, complainant must specify the provisions at issue;

(d) Contain a statement of the facts or law demonstrating defendant's failure to comply with the interconnection agreement and complainant's entitlement to relief. The statement must indicate that the remedy sought is consistent with the dispute resolution provisions in the agreement, if any. Statements of facts must be supported by written testimony with affidavits made by persons competent to testify and having personal knowledge of the relevant facts. Statements of law must be supported by appropriate citations. If exhibits are attached to the affidavits, the affidavits must contain the foundation for the exhibits;

(e) Designate up to three persons to receive copies of pleadings and documents;

(f) Include an executive summary, filed as a separate document not to exceed 8 pages, outlining the issues and relief requested; and

(g) Include any motions for affirmative relief, filed as a separate document and clearly marked. Nothing in this subsection precludes complainant from filing a motion subsequent to the filing of the complaint if the motion is based upon facts or circumstances unknown or unavailable to complainant at the time the complaint was filed.

(4) On the same day the complaint is filed with the Commission, complainant must serve a copy of the complaint on defendant's authorized representative, attorney of record, or designated agent for service of process. Service may be by telephonic facsimile, electronic mail, or overnight mail, but the complaint must arrive at defendant's location on the same day the complaint is filed with the Commission. Service by facsimile or electronic mail must be followed by a physical copy of the complaint the next day by overnight delivery.

(5) Within 10 business days after service of the complaint, defendant may file an answer with the Commission. Any allegations raised in the complaint and not addressed in the answer are deemed admitted. The answer must:

(a) Contain a statement of specific facts demonstrating that the defendant conferred with complainant in good faith to resolve the dispute and that despite those efforts the parties failed to resolve the dispute;

(b) Respond to each allegation in the complaint and set forth all affirmative defenses;

(c) Contain a statement of the facts or law supporting defendant's position. Statements of facts must be supported by written testimony with affidavits made by persons competent to testify and having personal knowledge of the relevant facts. Statements of law must be supported by appropriate citations. If exhibits are attached to the affidavits, then the affidavits must contain the foundation for the exhibits; and

(d) Designate up to three persons to receive copies of other pleadings and documents.

(6) On the same day as the answer is filed, the defendant must also file its response to any motion filed by complainant and its motions for affirmative relief. Each response and each motion must be filed as a separate filing. Nothing in this section precludes defendant from filing a motion subsequent to the filing of the answer if the motion is based upon facts or circumstances unknown or unavailable to defendant at the time the answer was filed.

(7) On the same day the answer is filed with the Commission, the defendant must serve a copy of the answer to the complainant's authorized representative, attorney of record, or designated agent for service of process.

(8) Complainant must file a reply to an answer that contains affirmative defenses within 5 business days after the answer is filed. On the same day the reply is filed with the Commission, complainant must serve a copy of the reply to defendant's authorized representative, attorney of record, or designated agent for service of process.

(9) A cross-complaint or counterclaim must be answered within the 10-business day time frame allowed for answers to complaints.

(10) The Commission will conduct a conference regarding each complaint for enforcement of an interconnection agreement.

(a) The administrative law judge (ALJ) schedules a conference within 5 business days after the answer is filed, to be held as soon as practicable. At the discretion of the ALJ, the conference may be conducted by telephone.

(b) Based on the complaint and the answer, all supporting documents filed by the parties, and the parties' oral statements at the conference, the ALJ determines whether the issues raised in the complaint can be determined on the pleadings and submissions without further proceedings or whether further proceedings are necessary. If further proceedings are necessary, the ALJ establishes a procedural schedule. Nothing in this subsection is intended to prohibit the bifurcation of issues where appropriate.

(c) In determining whether further proceedings are necessary, the ALJ must consider, at a minimum, the positions of the parties, the need to clarify evidence through the examination of witnesses, the complexity of the issues, the need for prompt resolution, and the completeness of the information presented.

(d) The ALJ may make oral rulings on the record during the conference on all matters relevant to the conduct of the proceeding.

(11) A party may file with the complaint or answer a request for discovery, stating the matters to be inquired into and their relationship to matters directly at issue.

(12) When warranted by the facts, the complainant or defendant may file a motion requesting that an expedited procedure be used. The moving party must file a proposed expedited procedural schedule along with its motion. The ALJ must schedule a conference to be held as soon as practicable to determine whether an expedited schedule is warranted.

(a) The ALJ will consider whether the issues raised in the complaint or answer involve a risk of imminent, irrevocable harm to a party or to the public interest.

(b) If a determination is made that an expedited procedure is warranted, the ALJ will establish a procedure that ensures a prompt resolution of the merits of the dispute, consistent with due process and other relevant considerations. The ALJ will consider, but is not bound by, the moving party’s proposed expedited procedural schedule.

(c) In general, the ALJ will not entertain a motion for expedited procedure where the dispute solely involves the payment of money.

Statutory/Other Authority: ORS 756
Statutes/Other Implemented: ORS 756.040 & 756.500
History:

PUC 1-2015, f. & cert. ef. 3-3-15
PUC 10-2009, f. & cert. ef. 8-26-09

Docket No. AR 688
Attachment 2

Attachment 2
Protection Schemes

Attachment 2 – Direct Transfer Trip

Issue

In Phase 2 of Staff's investigation into interconnection process and policies, requirements by the utilities for installing direct transfer trip (DTT)[5] were identified by Staff as a focal item in the technical topics workstream.[6] The main reason that DTT attracted close attention in Oregon and nationwide is that DTT, when required, can increase installation costs, especially for smaller projects and potentially to the point of making them not financially viable to proceed with by the customer. DTT may be required for many reasons, such as circuits equipped with high speed reclosing,[7] safety of maintenance personnel and general public,[8] substation equipment,[9] Ground Fault Overvoltage (GFOV),[10] and line protection and wildfire mitigation[11]. DTT is a mature technology, is very fast and is widely used by utilities as part of their overall protective schemes. However, it is important to note that as penetration of Distributed Energy Resources (DER) increases, technical research on protection schemes is progressing and code and best practices are evolving to constantly provide the most efficient and effective solutions.

Background

In Order 24-402, the Commission encouraged Staff to convene a working group for DTT.[12] Staff was already looking at DTT in docket UM 2111, and continued discussions with stakeholders on the topic, as recommended. In late 2024 and early 2025, the

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5 DTT is defined as a protection mechanism by which a local protective relay or device, upon detecting a fault or abnormal condition, sends a communication signal (usually utilizing fiber optics) to immediately disconnect a Distributed Energy Resource (DER) to prevent it from islanding with load.

6 Docket No. AR 688 - Informal Phase: Staff's Docket Announcement at 3, filed on April 8, 2026.

7 Area EPS automatic reclosing coordination to limit the duration of interruptions to customers - IEEE Std 1547.2-2023, 6.3.3.1 at 110 (tips, techniques and common practices).

8 Safety of utility maintenance personnel and general public from area EPS faults - IEEE Std 1547.2-2023, 6.2.1.1 at 92.

9 Failure by DER to detect some EPS faults within its zone of protection, such as at the substation or on transmission, to avoid damage to substation equipment or line devices - IEEE Std 1547.2-2023, 6.2.1.3 at 95 (tips, techniques and common practices).

10 Ground Fault Over Voltage (GFOV) when an upstream detective device opens (via 3V0/Phase Overvoltage schemes) - IEEE Std 1547.2-2023, 4.12.7 at 66 and 12.3.1 at 211.

11 IEEE power and Energy Society, Managing Wildfire Risks, IEEE power & energy magazine, January/February 2022.

12 Order No. 24-402 (UM 2322) at 7, filed on November 1, 2024.

technical topics workstream had two workshops dedicated to stakeholders discussing all the technical details related to DTT.[13,14]
In June 2026, Staff started working with Oregon's joint utilities to establish a streamlined process to reflect a transparent and consistent approach for testing conditions under which DTT functionality is appropriate for the utility to assign as an upgrade for specific projects. PacifiCorp's interconnection handbook for Oregon provided a good basis for Staff to develop a decision tree an engineer would typically go through to determine the criteria by which an interconnecting generator may require the implementation of DTT.[15]
In developing the proposed DTT criteria, Staff took into account universal engineering standards and guides, as well as policies and practices adopted by utilities across the country. Staff worked on refining those criteria over two informal rulemaking phase workshops with stakeholders,[16,17] where Staff discussed with stakeholders a decision tree to address the key elements that determine the proposed criteria.[18] There was general consensus on Staff's approach to document what utilities generally do in practice to screen interconnection applications for generators that may require DTT to be installed. Staff's proposed criteria are listed in Attachment 2-1.

Analysis
There is currently no universal approach to needing or not needing DTT in conjunction with the overall protection scheme. The reasonableness of requiring DTT and the ability to safely and reliably use lower cost alternatives is dependent on individual circumstances. Staff, however, is taking the initiative to demystify the issues surrounding DTT by introducing some basic criteria as common ground. Staff believes that utility protection engineers should identify protective equipment to mitigate the risks on a project-specific basis. Staff expects utilities to identify reasonable, cost-effective solutions for protective equipment to assign to a given project and consider alternatives on a case-by-case basis to mitigate risk from afore-mentioned reasons requiring DTT.

To this end, Staff is not introducing rules dictating how utilities can identify and assign the costs of specific protective schemes to projects. Staff believes that having

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13 Docket No. UM 2111 - Staff's Workshop 1 Presentation on Dec. 5, 2024, filed on Dec. 4, 2024.
14 UM 2111 - Investigation Into Interconnection Process And Policies - Phase 2 Staff Workshop on Jan 22, 2025, video recording available from Oregon Public Utility Commission's Archived Events at https://oregonpuc.granicus.com/ViewPublisher.php?view_id=2.
15 Pacific Power Oregon Distribution Interconnection Handbook, 4.4.2 Direct Transfer Trip, posted on 06.05.2026 at 13, available at https://www.oasis.oati.com/ppw/ (accessed on Aug. 27, 2026).
16 AR 688 - Interconnection Rules Informal Rulemaking Updated Proposal – Workshop on June 24, 2026, presentation slides and video recording available from Oregon Public Utility Commission's Archived Events at https://oregonpuc.granicus.com/ViewPublisher.php?view_id=2 .
17 Docket No. AR 866 - Informal Phase: Staff Workshop Presentation Slides on July 20, 2026, filed on July 20, 2026.
18 Key elements of the decision tree include the interconnection project generation type (inverter-based or not), the project generation capacity and the aggregate generation capacity from all existing customers on the affected circuit or substation.

transparent and reasonable approaches to identifying protection schemes for each project seeking interconnection spelled out in the utility handbook is the most practical approach and will remain adaptable to changing code and research. Staff recommends that the Commission direct utilities include an approach consistent with the basic criteria listed in Attachment 2-1 in the annual interconnection handbook update in 2027. Staff also recommends in the proposed criteria that whenever the utility deviates from fully complying with the criteria for a project, it must explain to the interconnection applicant the reasons for the exception of requiring or not requiring DTT, whether due to adopting alternatives or other reasons.

Stakeholder Comments
In general, all stakeholders appeared to agree with the approach that Staff took to develop the criteria for DTT. Interstate Renewable Energy Council, Inc. (IREC) expressed its support by saying "[a] standardized approach will improve predictability for applicants, promote consistency across the state, and help ensure costly protection requirements are imposed only when necessary to maintain grid safety and reliability".[19] Sustainable Northwest also supported Staff's approach and said that "[w]e support Staff's effort to establish consistent, transparent, published criteria for when Direct Transfer Trip is required across all three utilities, and we encourage the Commission to hold that standard uniform rather than allowing each utility to set divergent criteria, consistent with the standardization goals in UM 2111".[20]

Staff sought feedback on the proposed criteria for DTT from stakeholders after the second informal rulemaking phase workshop on July 20, 2026, to further discuss the Staff proposal. In that workshop, the suggestion of alternative protection schemes to DTT was raised by RWE citing an article that showed New England's National Grid had endorsed alternatives to DTT.[21] To this point, Staff sought comments from stakeholders to share any published and peer-reviewed information on any DTT alternative schemes that are theoretically proven and practically tested to provide the same functionality as DTT, as applied all operational scenarios.

On the content of the proposed criteria, PacifiCorp commented that "[u]tilities throughout the region should be free to set individual minimum kW thresholds for the application of DTT depending on the loading and topology of their system". No other stakeholder made any comments on the wording of the proposed criteria.

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19 Docket No. AR 688 - Informal Phase: Interstate Renewable Energy Council, Inc.'s Comments on Staff's Proposal and June 24, 2026 Workshop at. 6, filed on July 10, 2026.

20 Docket No. AR 688 - Informal Phase: Sustainable Northwest joint comments at 13, filed on July 10, 2026.

21 T&D World, National Grid's Blueprint for DG Interconnections, Jan. 25, 2018, available at National Grid's Blueprint for DG Interconnections | TD World (accessed Aug. 27, 2026).

In response to PacifiCorp's comment, Staff would like to point out that the minimum capacity of 500 kW for 3-phase Inverter-based resource (IBR), chosen as a threshold that warrants investigating the requirement for DTT, was copied from the threshold stated in Pacific Power's latest interconnection handbook (posted on June 5, 2026), as well as PacifiCorp's DER interconnection policy book.[22] In the first informal rulemaking phase workshop on June 24, 2026, upon Staff's questioning of the appropriateness of the threshold's level, PacifiCorp said that it chose the 500 kW threshold based on the common practice of the majority of utilities nationwide. PGE made a passing comment in the first workshop on June 24, 2026, that a minimum capacity of 1,000 kW or above is their main concern when it comes to requiring DTT. Nevertheless, Staff has since added a clause to the proposed criteria that allowed deviation from the proposed criteria provided that safety and reliability obligations are met. In making this addition, Staff agrees that the loading vs circuit or substation capacity may not agree with the 500 kW threshold and the threshold may need to be changed on a case-by-case basis on some occasions.

With regards to alternatives to DTT, there were mixed opinions. Both PacifiCorp and PGE commented that there were no alternatives to DTT which would quickly trip the DER to eliminate a safety or reliability risk upon detection of an adverse system condition, and that the DER built-in sensing and tripping capabilities are unable to detect and act on time to eliminate such risk. Both utilities also agreed that fast tripping induced by the inverters will be challenged by the system support and ride-through standards required to be implemented in inverters since August 2024. In particular, PacifiCorp emphasized that wildfire mitigations require a rapid disconnection of the DER much faster than the inverter could handle.[23] PGE also added that some alternatives would only work for inverters meeting UL1741SB (August 2024 and later), which Staff understood, after further clarification from PGE, to mean that PGE has a high volume of inverters that are based on IEEE 1547-2003 that don't have the additional capabilities required for fast tripping.

On the other hand, the Interconnection Trade Groups (ITG) emphasized that DTT should not be a default requirement by the utilities and pointed out some research papers demonstrating viable alternative approaches, where DTT would not be required or appropriate in all cases.[24]

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22 PacifiCorp Facility Connection (Interconnection) Requirements for Distribution Systems (policy 138), revision 12, May 26, 2026 at 10.

23 Docket No. AR 688 - Informal Phase: PacifiCorp's Comments on Staff's July 20th Workshop at 5, filed on August 10, 2026.

24 Docket No. AR 688 - Informal Phase: Interconnection Trade Groups' Comments on Direct Transfer Trip at 1, filed on Augst 13, 2026.

Staff agrees that DTT should not be required as the default. This is the exact reason for Staff to embark on the initiative to define baseline criteria, which when applied on an interconnection project basis would narrow down the conditions upon which DTT would be required. Staff has conducted extensive research on alternatives to DTT. A recent report (SAND2025-01668O) by Sandia National Laboratories, and supported by the US Department of Energy (DOE) Interconnection Information eXchange (i2X) program, examines all alternative methods to DTT that perform the basic functions of ensuring that distribution generation is deenergized when the utility circuit breaker opens and the circuit is no longer supplied by the utility, but by one or more DER.[25] The Sandia report highlights the pros and cons of alternatives to DTT.

In the Sandia Labs report, the first alternative to DTT is DTT itself but instead of using fiber communications, it uses other means of communication, such as radio or cellular networks. To clarify this point, the elevated cost for DTT is often the result of the fiber communications that are generally used for this type of protection, however, when a reliable communications network is present the use of other types of networks could be a lower cost alternative. However, the utility requires confidence that under all conditions the network availability supports the instantaneous response needed for the operational technology. This alternative approach is not always successful for topographical or communication reliability reasons. As mentioned by one of the utilities during the first informal rulemaking phase workshop on June 24, 2026, radio-based DTT is already being used in Oregon for some projects. Another simple alternative stated in the ITG comments is reducing a project's output such that DTT is not required.[26] Staff can confirm that this option has already been implemented at least once in a past project in Oregon.

The most prominent alternative in the SAND2025-01668O report is a combination of two built-in functions available in newly certified inverters; namely the undervoltage relaying, specifically the "UV2" function (UV) required by IEEE 1547-2018 and modified by IEEE Std 1547-2020a, and the unintentional islanding detection (UID) function, which is also required by IEEE Std 1547-2018. This lowest cost option is named "UV + UID". Out of several disadvantages of UV + UID, Staff realizes that there is a key disadvantage in each function. First, legacy DER designed to a standard pre-dating IEEE Std 1547-2018 may not have the "UV2" function's trigger. This can be especially problematic with high volumes of DER of that age, as experienced by PGE. As the report mentions, a "UV2" relay can be added externally at a cost, but may not

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[25] Sandia National Labs, Direct Transfer Trip With Distributed Energy Resources, and Alternatives, SAND2025-01668O, January 2025, available at https://www.sandia.gov/app/uploads/sites/273/2025/12/SAND2025-01668O_11252025_DOEapproved.pdf (accessed on Sep. 03, 2026).

[26] Limiting system size to avoid a requirement for DTT is a possible method stated in IEEE Std 1547.2-2023, Annex H, H.1 at 258.

consistently act in the desired timeframe required by DTT. Second, the changes to enable the grid support and ride through capabilities by the inverter may interfere with the autonomous anti-islanding, especially when inverters from different vendors are co-located on one bus.[27] There is also the concern with the emergence of grid forming inverters and the lack of research to determine their impact on UID.

Based on the literature, Staff can conclude that although DTT alternatives do exist, each alternative has gaps in covering the risk of the DER failing to trip on time under all DER configurations and operating conditions. Given the evolving research on risk detection and mitigation methods, Staff has added in the proposed criteria that the utility may not require DTT if an equivalent and viable alternative is available.

ITG also recommended that utilities perform a risk of islanding (ROI) study as a last step before resorting to DTT.[28] Before further exploring ITG's recommendation, Staff would like to hear from utilities about the practicality of conducting an ROI study. Staff is aware of some utilities, such as National Grid, which introduced an extra step in the anti-islanding requirements to allow for a risk of islanding (ROI) study performed upon the developer request, as a last step after applying several tests in the screening process of UI protection practice. Although National Grid stipulates specific UID methods, it does require DTT in "some cases where a DER's on-site equipment (such as voltage and frequency relaying or islanding detection) cannot reliably detect utility islands" and "a significant risk of islanding exists".[29]

Staff understands that there are many UID methods implemented in inverters. As explained in the SAND2025-01668O report, the effectiveness of specific manufacturers' methods for detecting UI can be difficult to determine without an electromagnetic transient study (EMT) using the actual (not generic) of each DER model in the study area.[30] This will add complexity to the study, let alone the time and cost added to the project, considering the scarcity of worldwide expertise of engineers who are qualified and experienced to conduct EMT studies. In addition, Staff also cautions that it will be almost impossible to determine zero risk of unintentional islanding by a desktop study performed after failing all the preceding tests in the DTT screening criteria.

Conclusion
The small generator interconnection rules currently state that a public utility must:

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27 Sandia National Labs, Evaluation of Multi-Inverter Anti-Islanding with Grid Support and Ride-Through and Investigation of Island Detection Alternatives, SAND2019-0499, January 2019 at 3.

28 Docket No. AR 688 - Informal Phase: Interconnection Trade Groups' Comments on Direct Transfer Trip, filed on August 13, 2026 at 2.

29 National Grid, Supplement to Specifications for Electrical Installations, ESB 756 – 2026, section 6.2.1 at 22.

30 Sandia National Labs, Direct Transfer Trip With Distributed Energy Resources, and Alternatives, SAND2025-01668O, January 2025 at 17.

> Identify any adverse system impacts on an affected system caused by the interconnection of a small generator facility to the public utility's transmission or distribution system. The public utility must determine what actions or upgrades are required to mitigate these impacts.

And that the interconnection applicant, "must pay the reasonable costs of any system upgrades."[31]

In applying the existing rules to DTT, Staff is focused on ensuring that the costs utilities assign to interconnection customers are predictable and no higher than necessary to mitigate adverse safety and reliability impacts. Staff believes that having transparent, reasonable criteria for a project-specific review in the utility interconnection handbook will be most effective at advancing those goals, while remaining adaptable to individual project circumstances, changing standards, and best practices.

Staff's Recommendation: Direct investor-owned utilities in Oregon to include in their interconnection requirements handbooks a detailed description of the approach they will use in identifying DTT in small generator interconnection studies, consistent with the criteria in Attachment 2-1, in the annual interconnection handbook update in 2027.

[31] OAR 860-082-0035(4).

Docket No. AR 688
Attachment 2-1

Attachment 2-1 – Proposed Criteria for Direct Transfer Trip

Staff's proposed DTT criteria for utility interconnection handbooks:

- Direct Transfer Trip may be required for a three-phase generator interconnection application request, under any of the following conditions:
    - If the aggregate capacity of all IBR generating resources, including the current interconnection request, exceeds 80% of the minimum load of the substation transformer, direct transfer trip (DTT) shall be required for the requested interconnected IBR resource with a total aggregate inverter nameplate capacity of 500 kW or greater. In the case of inverter based solar interconnection, the calculation will be based on 80 percent of the daytime minimum load.
    - If the aggregate capacity of all non-IBR generating resources, including the current interconnection request, exceeds 33 percent of the minimum load of the circuit, DTT will be required regardless of the aggregate nameplate capacity of the requested interconnected non-IBR resource.
    - If the aggregate capacity of mixed IBR and non-IBR generating resources, including the current interconnection request, exceeds 80 percent of the minimum load of the substation transformer, direct transfer trip (DTT) shall be required for the requested interconnected IBR resource with a total aggregate inverter nameplate capacity of 500 kW or greater and any nameplate capacity of the requested interconnected non-IBR resource.
- If DTT is determined to be required for an interconnection project by these criteria, the utility, at its discretion, may approve the interconnection without the requirement of installation of a DTT, if an equivalent and viable alternative is available or for other justifiable reasons, and its approval is consistent with the utility's safety and reliability obligations. Conversely, the utility may require DTT to be installed even though the criteria do not determine that DTT is required, if the utility's safety or reliability obligations are compromised.
- In either case if the utility makes an alternative decision inconsistent with these criteria, whether resulting in requiring or not requiring DTT, the utility must provide valid reasons to the interconnection applicant for deviating from the outcome of following these criteria.

Attachment 3
Disconnect switches

Attachment 3 – Disconnect Switches

Issue

In Phase 2 Staff's investigation into interconnection process and policies, stakeholders identified concerns related to the requirement by utilities for customer generators to install multiple disconnect switches for one net metering interconnection.[32] OAR 860-039-0015 requires, with exceptions for certain customer-generators with certified inverter-based systems and those with systems installed prior to the time the rule was adopted, that a net metering customer must install and maintain a manual disconnect switch that will disconnect the net metering facility from the public utility's system.[33] The disconnect switch must be a lockable, load-break switch that plainly indicates whether it is in the open or closed position.[34] The disconnect switch must be readily accessible to the public utility at all times and located within 10 feet of the public utility's meter unless the public utility approves a location beyond this distance prior to the installation of the net metering facility.[35]

Background

Issues with disconnect switches were raised by Oregon Solar + Storage Industries Association (OSSIA) in its comments on the scope of Phase 2 of Docket No. UM 2111 (Investigation into Interconnection Process and Policies) in October 2024.[36] OSSIA's concern was focused on residential installations and the integration of batteries and disagreement between utilities and customers on the location and specific type of disconnect switches. OSSIA stated utility requirements often resulted in redundant disconnect switches stacked at the utility meter and/or extended circuit runs to locate switches by the meter; both outcomes proving costly to customers. OSSIA also noted that the utilities did not have consistent requirements, which created confusion. Given the confusion around the utility disconnect requirements imposed under OAR 860-039-0015, and the overlap with disconnect requirements of prevailing building and electrical codes, OSSIA recommended reevaluation of the OAR 860-039-0015 disconnect switch requirements, including whether the utilities should follow the same codes and standards and use the same disconnects as first responders.

In March 2026, OSSIA sent a letter to Staff stating the concern raised in its October 2024 comments had intensified with the deployment of residential batteries, as utilities developed individualized policies.[37] In that letter, OSSIA emphasized, among other things, the need to re-examine and modernize OAR 860-039-0015 to apply consistently

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32 Docket No. AR 688 - Informal Phase: Staff's Docket Announcement at 3 (April 8, 2026).
33 OAR 860-039-0015(2).
34 OAR 860-039-0015(2).
35 OAR 860-039-0015(2) and (2)(b).
36 Docket No. UM 2111 - OSSIA's comments at 3 (October 11, 2024).
37 Docket No. UM 2111 - OSSIA's Comments on Issues and Recommendations on DER Disconnects (March 23, 2026).

to battery systems and microgrids and for utilities to propose "avenues to ensure standardization between utilities and first responders that acknowledge the diversity of project topologies".[38]

Staff held two informal rulemaking phase workshops with stakeholders.[39,40] In the first workshop on June 24, 2026, Staff focused on the concept of limiting utilities to requiring only one disconnect switch for net metering facilities and batteries behind the same meter. This concept was inspired by Pacific Power's latest interconnection handbook, which stated that PacifiCorp's 'preferred' design was to have one switch on the DC side of the system to isolate the local generation from the utility service.[41] Extensive discussions among stakeholders followed on the appropriate locations of the switch and the different use cases of the switch from the point of view of each party. The main issue of debate was whether opening the switch should or should not allow a battery to serve the customer's load during power outages, an issue that is critical to maintain resiliency particularly when outages occur for extended periods.

After the first workshop, upon request from Staff, PacifiCorp shared with Staff and other stakeholders the Company's understanding of the use cases of the disconnect switch in terms of emergency and non-emergency operation.[42] The Company also described the different options for the configuration and number of switches that are available to customers, based on both the Company's defined use cases and the type of switches in the market that would satisfy those use cases.

In the second workshop with stakeholders on July 20, 2026, Staff presented a list of emergency and non-emergency use cases, based on the National Fire Protection Association's National Electrical Code (NEC) requirements for disconnecting means for both solar battery energy system and PacifiCorp's use cases. The workshop discussion revolved around the role of both utility and emergency personnel and the codes and rules governing the requirements for disconnect switches in each use case. The discussion indicated a consensus to limit the number of disconnect switches behind a single utility meter. Towards the end of the workshop, stakeholders discussed that a possible solution to satisfy all parties would be a requirement for the utilities to use the same means required by the NEC to disconnect power production sources.

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38 Ibid at 5.

39 AR 688 - Interconnection Rules Informal Rulemaking Updated Proposal – June 24, 2026 Workshop presentation slides and video recording available from Oregon Public Utility Commission's Archived Events at https://oregonpuc.granicus.com/ViewPublisher.php?view_id=2.

40 Docket No. AR 866 - Informal Phase: Staff Workshop Presentation Slides (July 20, 2026).

41 Pacific Power Oregon Distribution Interconnection Handbook, 4.4.2 Direct Transfer Trip at 13 (June 5, 2026), available at https://www.oasis.oati.com/ppw/ (accessed on Aug. 27, 2026).

42 PacifiCorp's email to Staff, Disconnect Switches - Use Cases (July 16, 2026). Email is available at Docket No. AR 688 - Informal Phase: OSSIA Comments, at 4-6 (August 10, 2026).

After the second workshop, Staff followed up with a request to stakeholders to send suggestions on how to align the requirements of OAR 860-039-0015 for disconnect switches and the disconnecting means required by the NEC for both Solar Photovoltaic (PV) systems and Energy Storage Systems (ESS).[43]

PacifiCorp responded to Staff that the disconnect switch is primarily a safety switch and operated by utility personnel before pulling the meter to premises with solar and storage systems. PacifiCorp clarified the disconnect switch allows utility personnel to prevent any back feed current from the customer's energy source to the utility meter before any work is done on utility equipment.[44] The Company explained that the NEC safety has its own requirements regarding the placement and operation of the disconnect switch in the protection and operation of a branch circuit.[45]

Analysis
Staff determined that the first step to resolve the issue of duplication of disconnect switches and disputes about their locations is to consider the purpose of a disconnection switch. In the 2007 rulemaking to adopt rules related to net metering, Staff stated that "[t]he purpose of a manual, lockable disconnect switch is to ensure the safety of utility personnel when working on customer meters or electrical lines".[46] In that rulemaking, based on the requirements by NEC, the National Electrical Safety Code (NESC) and Institute of Electrical and Electronics Engineers (IEEE) Standard 1547, Staff recommended "a manual, lockable disconnect switch be required for all net metering facilities, with one exception: certified inverter-based systems, such as solar electric systems, with up to 30 amps of connected generation behind the inverter".[47]

The primary issue with respect to disconnection switch requirements raised by stakeholders in the 2007 rulemaking (AR 515) was the potentially high installation cost associated with requiring the disconnect switch to be in proximity of the meter. Staff addressed this concern in its 2007 proposal by specifying the switch could be located more than ten feet away from the meter if the location was approved by the utility. Notwithstanding stakeholders' concerns regarding the potentially high cost, the Commission adopted Staff's proposed rule.[48] The rules adopted by the Commission also included language specifying the disconnect switch must allow for a "whole service disconnect" for an entire facility to disconnect (i.e., lock out and tag out) the net

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43 Docket No. AR 688 - Informal Phase: Staff's July 20 Workshop Follow up Announcement seeking additional comments at 3 (July 24, 2026).
44 Docket No. AR 688 - Informal Phase: PacifiCorp's Comments on Staff's July 20th Workshop at 5 (August 10, 2026).
45 Ibid.
46 Docket No. AR 515 - Staff's Opening Comments at 4 (April 11, 2007).
47 Ibid at 5.
48 *In the Matter of the Public Utility Commission of Oregon, Rulemaking to Adopt Rules Related to Net Metering*, AR 515, Order No. 07-319 (July 24, 2007).

metering facility to prevent the release of energy back into the utility's network as a safeguard for utility employees during service, maintenance or emergency activities.[49]

Staff agrees with Charles Bonville's comments[50] that PacifiCorp's latest comments on August 10, 2026, made two important assertions regarding the disconnect requirements: 1) the utility regards the disconnect switch as a safety switch that is operated by utility personnel to prevent any back feed current from the customer's energy source to the utility meter before any work is done on utility equipment, and 2) the NEC safety has different requirements regarding the protection and operation of the disconnect switch in the protection and operation of a branch circuit.

Staff believes that there is a general understanding of the use case of the disconnect switch as a safety measure, whether for the requirements of the rules or the NEC. This understanding is confirmed by PacifiCorp's posted public information document for customer generation, where it states that the disconnect switch is a safety component to turn off customer generation and that it typically would only be used by emergency responders, such as a fireman or a lineman.[51] This statement by PacifiCorp should also support the customer's choice of using a whole service disconnect, which would satisfy the purpose of the disconnect switch of preventing the release of energy back into the utility's network. However, as Staff has cautioned during the initial rulemaking of the rule that choice would put the premises at greater risk of electric power interruption by the utility.[52]

With regards to the requirements by the NEC, as compared to the Oregon Administrative Rules, Staff believes that a single disconnect switch should be able to serve the purposes of both rule and safety code, which are to disconnect the energy source from the utility's system or be a means to isolate Solar Photovoltaic (PV) systems and Energy Storage Systems (ESS). To test this belief, Staff compared the type and location of the disconnect switch required by both the rules and the NEC.

For Solar PV systems, Article 690.15 of the NEC requirements are:[53]

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49 The changed proposed by Sustainable Northwest was simply striking the phrase "and the customer-generator's electric service" at the end of the first sentence in 860-039-0015(2) that states that the disconnect switch "will disconnect the net metering facility from the public utility's system". See Commission Order No. 07-319 at 8-9.

50 Docket No. AR 688 – Informal Phase: Charles Bonville's Comments at 1 (August 13, 2026).

51 PacifiCorp, Key Components of a Solar Generation System, available at https://www.pacificpower.net/savings-energy-choices/customer-generation.html (accessed on August 31, 2026).

52 Docket No. AR 515 - Staff's Supplemental Comments at 4 (May 9, 2027).

53 National Fire Protection Association, NFPA 70, National Electrical Code (NEC), 2026 Edition, Article 690.15 (C), Equipment Disconnecting Means at 682 (70-679).

(C) Equipment Disconnecting Means. Equipment disconnecting means shall comply with all of the following:
(1) Have ratings sufficient for the maximum circuit current, available fault current, and voltage that is available at the terminals
(2) Simultaneously disconnect all current-carrying conductors that are not solidly grounded to the circuit to which it is connected
(3) Be externally operable without exposing the operator to contact with energized parts and shall indicate whether in the open (off) or closed (on) position
(4) Be one of the following types:
   a. Manually operable switch or circuit breaker
   b. Load-break-rated pull-out switch
   c. Device listed or approved for the intended application

(D) Location and Control. Isolating devices or equipment disconnecting means shall comply with one or more of the following:
(1) Be located within the equipment
(2) Be located in sight from and readily accessible from the equipment for those to whom access is required
(3) Be lockable in accordance with 110.25
(4) Be located in an enclosure with a door or cover capable of being locked closed that restricts access to the operations of the disconnecting means
(5) Be provided with remote controls to activate the disconnecting means that comply with one of the following:
   a. The disconnecting means and their controls are located within the same equipment.
   b. The disconnecting means is lockable in accordance with 110.25, and the location of the controls are marked on the disconnecting means.

For Energy Storage Systems (ESS), the requirements are similar to those for PV systems and are shown in Article 706.15 of the NEC as follows:

706.15 Disconnecting Means. Means that shall be provided to disconnect the ESS from all wiring systems, including other power production sources, utilization equipment, and other premises wiring in accordance with 705.20 and 706.15(A) through 706.15(D).
(A) Type of Disconnect. ESS disconnecting means shall simultaneously disconnect the ungrounded conductors of an ESS.
(B) Location and Control. The disconnecting means shall be readily accessible and shall comply with one or more of the following:
(1) Be located within the ESS
(2) Be located visible and within 3 m (10 ft) from the ESS
(3) Be lockable in accordance with the 110.25, or the enclosure providing access to the disconnecting means be capable of being locked closed.
Where controls to activate the disconnecting means of an ESS are used and not located within sight of the ESS, the disconnecting means shall be capable of being locked in accordance with 110.25, and the location of the controls shall be marked on the disconnecting means.

The permissible option of having a single disconnecting means for all power sources and the type of disconnecting means are both described in Article 705.20 of the NEC as follows:

705.20 Source Disconnecting Means. Means shall be provided to disconnect power source output conductors of electric power production equipment from conductors of other systems. A single disconnecting means shall be permitted to disconnect multiple power sources from conductors of other systems. If a power source service disconnecting means meets the requirements of both 705.11 and 705.20(A) through 705.20(F), a separate source disconnecting means is not required. A single disconnecting means shall be permitted to disconnect multiple power sources from conductors of other systems. Power source disconnecting means shall comply with 705.20(A) through 705.20(G).

(A) Location. Disconnecting means shall be readily accessible.

(B) Ratings. Disconnecting means shall have ratings sufficient for the maximum circuit current, available fault current, and available voltage available at the terminals of the disconnecting means.

(C) Type. Disconnecting means shall simultaneously disconnect all ungrounded conductors of the circuit and be one of the following types:

(1) A manually operable switch or circuit breaker
(2) A load-break-rated pull-out switch
(3) A power-operated or remote-controlled switch or circuit breaker that is manually operable locally and opens automatically when control power is interrupted
(4) A device listed or approved for the intended application

OAR 860-039-0015(2) ("the rule") requires that the "disconnect switch must be a lockable, load-break switch that plainly indicates whether it is in the open or closed position."

When comparing the NEC ("the code") and the rule, Staff sees that the rule requirements for the type of disconnect switch and its specifications are all included in the NEC relevant articles for Solar PV and ESS. The rule and code differ in that the NEC allows for several types of disconnecting means for both PV Solar and Battery Storage systems, as per Articles 690.15 and 705.20. Some of the disconnection means allowed under the code would not satisfy the rule. For example, circuit breakers, which are allowed under the NEC cannot be used in place of a disconnect switch because the disconnect switch has to be lockable under OAR 860-039-0015(2).

With regards to the location of the disconnect switch, both the code and the rule have different requirements, but both have provisions for allowing the disconnect switch to be located elsewhere provided that certain conditions being met.

As per Articles 690.15 and 706.15 of the code**,** the NEC requires the switch to be readily accessible and be located within the equipment the switch is meant to isolate, but with the option of having the controls of the disconnecting means not located within sight of the equipment and the location of the controls marked on the disconnecting means. According to the rule, the utility disconnect must be located within 10 feet of the public utility's meter, unless the utility agrees to a different location and the customer posts

permanent instructions at the meter indicating the precise location of the disconnect switch.[54]

For both the code and the rule, the requirements for the location of the disconnecting means or switch with options to locate it farther away from the preferred location are based on a the need for accessibility when emergency or utility personnel arrive at a facility, but allow flexibility when situations would not allow the switch to be at the preferred location. In this case, Staff continues to support a requirement that the utility approve the location of the utility disconnect switch if it is not within ten feet of the meter, as per the existing rule.

In proposing to require that utilities allow customers to use one disconnect switch per interconnection, Staff cautions this requirement is intended only to ensure compliance with OAR 860-039-0015 and safety obligations under the NESC.[55] Consistent with the NESC, there needs to be a visible disconnect switch to separate the downstream system from back feed power; in addition, should the project design deviate from the NEC (with regards to emergency response personnel's access to disconnect switches), the interconnection applicant must provide documentation to the utility that the Jurisdiction Having Authority (JHA) has approved the proposed configuration. As such, the approval of the switch by the utility does not relieve the customer from its obligations towards the requirements of the NEC, where approval by the JHA) may still be needed.

Conclusion
In summary, for maintaining the safety requirements for both utility and emergency personnel, Staff is not proposing changes to the rule for disconnect switches. To address the issue of having multiple disconnect switches per net metering interconnection, Staff believes the Commission should require that utilities include a provision in their interconnection handbooks that the default requirement is to have a single disconnect switch as long as certain conditions are met.

Staff's Recommendation: Direct the Oregon investor-owned utilities to include in their next update to their interconnection handbooks an option for the customer to install a single disconnect switch per customer interconnection, consistent with the following conditions:

1. When the utility does not approve the customer's design that is based on a single disconnect switch for the entire facility, the utility must provide the customer with technical reasons when the utility requires more than one disconnect switch.

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54 OAR 860-039-0015(2)(b).
55 IEEE, 2023 National Electrical Safety Code® (NESC®), Section 444(C), De-energizing equipment or lines to protect employees at 283.

2. When the customer obtains approval by the utility to use a single disconnect switch, the utility must approve the type of disconnect switch before its installation.
3. In the case that the utility's approved disconnect switch is also used to act as the disconnecting means for emergency personnel, the utility may require the customer to provide the JHA sign-off to prove that the customer has met NEC's obligations before final interconnection approval by the utility.

Docket No. AR 688
Attachment 4

Attachment 4

Staff Quarterly Reports Data Fields

The following table contains the data to track in the quarterly reports. The columns are for Excel tabs, with the title in the top row, and the data requested in the cells below.

Quarterly Interconnection Report Data Needed		
Applicant information	**Study Timelines**	**Construction timelines**
Unique project identifier	Unique project identifier	Unique project identifier
Tier requested	Date of submission of Interconnection Application	Date IA Executed
Facility type - Motive force	Date of utility's acknowledgment of receipt of Interconnection Application	Date of Site Visit
Nameplate capacity	Date Interconnection Application deemed complete*	Milestone in IA
Storage included	*Include date(s) for any information related to requests for clarification, or other issues with incomplete applications, and date(s) of any responses	Party responsible for completing milestone
Storage capacity	Date applicant notified application is complete	Milestone contract date
Export capacity	Date scoping meeting held	Milestone Completed Date
Project zip code	Date of completion of screening review and provision of results	Reason milestone missed
Basic Telemetry Configured	Did applicant pass initial screens? (Y/N)	IA addendum needed?
Required Interconnection Facilities	If screens failed, did applicant: (A) Request an applicant options meeting; (B) Undergo supplemental review in accordance with OAR 860-082-0063; or (C) Continue evaluating the application under Tier 4.	Date addendum provided by Utility

Estimated Cost of Facilities presented to applicant	Date applicant submit executed Supplemental Review	Date addendum executed by applicant
Actual cost of facilities	Date of completion of Supplemental Review	Explanation of any additional construction delays agreed to by applicant and utility
Required System Upgrades	Results of Supplemental Review (Pass/Fail)	Total number of days impacted by additional construction delays
Estimated Cost of Upgrades	Was Feasibility Study conducted? (Y/N)	Provide amount of any cost reductions for delayed construction
Actual cost of upgrades	Date Feasibility Study Agreement sent to applicants	
Circuit name	Date applicant returned executed Feasibility Study Agreement	
Any penalties paid for late studies or construction	Was System Impact Study conducted (Y/N)	
Explanation for any changes to the project or project status	Did Applicant request Limited Operations Study? (Y/N)	
	Date applicant provided System Impact Study	
	Date applicant returned executed System Impact Study Agreement	
	Date System Impact results provided to applicant?	
	Provide amount of any cost reductions for late System Impact Study	

	Was Facilities Study conducted? (Y/N)	
	Was a site visit requested for Facilities Study (Y/N)	
	Date of Site Visit	
	Date Facilities Study agreement sent to applicant	
	Date applicant returned executed Facilities Study Agreement	
	Date Facilities Study results provided to applicant?	
	Provide amount of any cost reductions for late Facilities Study	
	Date Draft Interconnection Agreement provided to applicant.	
	Date Interconnection Agreement executed	