ITEM NO. RM1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: October 4, 2022

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: September 26, 2022

TO: Public Utility Commission

FROM: Madison Bolton

THROUGH: Bryan Conway, Caroline Moore, Scott Gibbens **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. AR 651)
Staff's revised recommendation to move the Direct Access Rulemaking to the formal stage.

STAFF RECOMMENDATION:

Staff recommends that the Oregon Public Utility Commission (Commission) adopt Staff's policy guidance on Direct Access caps, approve Staff's request to open a formal rulemaking on Direct Access (DA), and issue a notice of proposed rulemaking to adopt permanent rules addressing the revision to OAR Chapter 860, Division 038 included in Attachment A.

DISCUSSION:

Issue

Whether the Commission should adopt Staff's recommendation on Direct Access caps and open a formal rulemaking to adopt revisions to Direct Access rules in OAR Chapter 860, Division 038.

Applicable Rule or Law

Pursuant to ORS 756.060, the 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."

The Oregon Administrative Procedures Act provides procedural guidelines for adopting or amending administrative rules, including specific processes for contested case proceedings.

OAR 860-038-0001 applies the Division 038 rules to electric companies and electricity service suppliers (ESS) serving Direct Access customers in the state of Oregon.

Analysis

Procedural Background
On June 10, 2019, the Commission opened Docket No. UM 2024 to address the Alliance of Western Energy Consumers' (AWEC) petition for a general investigation into long-term DA programs, which noted there was a near-term need to address Direct Access with regards to issues like the changing energy landscape, cost shifting, and competitiveness of a retail market, among others.[1] The Commission granted AWEC's petition in Order No. 19-271.[2]

On October 1. 2021, Administrative Law Judge (ALJ) Christopher J. Allwein's memorandum outlined the Commission's new direction for the docket.[3] The Commission determined that a phased sequence with a non-contested rulemaking followed by a contested case process would allow for more "effective definition, narrowing, and processing of the issues in this proceeding."[4] The memorandum narrowed the scope of issues in the first phase to Direct Access requirements stemming from House Bill (HB) 2021 and some elements of the parties' straw proposals. As part of Phase I, Staff drafted proposed language changes to Division 38 and developed policy guidance on a small set of additional issues.

Following roughly nine months of proposals, comments and workshops, Staff proposed moving to a formal rulemaking at the July 12, 2022, Public Meeting.[5] Stakeholders expressed a range of perspectives on Staff's draft rules and proposal to move to a formal rulemaking including recommendations to revise the non-bypassable charge rule language, add rules that address confidential information in the ESS Emission Planning Reports, and exclude preferential curtailment frameworks at that stage.

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[1] INITIAL (APPLICATION, COMPLAINT, PETITION), 6/10/2019 (state.or.us).
[2] UM 2024, Order No. 19-271.
[3] UM 2024 Memo 10-01-21.pdf (state.or.us).
[4] Id.
[5] Staff Report for July 12, 2022, Public Meeting RM1.

The Commission rejected Staff's proposal on the basis that further policy guidance was needed regarding DA program caps, Provider of Last Resort (POLR) obligations, and the feasibility of preferential curtailment. The Commission recommended that Staff develop a revised proposal for these topics and request moving to a formal rulemaking after proposing additional rule language.

On September 1, 2022, Staff filed a straw proposal that enables preferential curtailment of certain DA customers, adds confidentiality protocols for ESS Emission Planning Reports, revises Staff's original non-bypassable charges language, and outlines criteria for considerations to expand DA program caps if applicable. Multiple parties submitted comments on Staff's straw proposal on September 15, 2022, including:

- AWEC
- Brookfield Renewable Trading and Marketing LLP (Brookfield)
- Climate Solutions and Green Energy Institute
- The Northwest and Intermountain Power Producers Coalition (NIPPC)
- Oregon Citizens' Utility Board (CUB)
- PacifiCorp (PAC)
- Portland General Electric (PGE)
- QTS Investment Properties Hillsboro (QTS)

Staff developed the final recommended rule language in Attachment A while considering the redlines and comments that parties submitted.

Summary of Staff's Revised Division 038 Rules and Parties' Input

The revised rule language in Attachment A includes changes to the following sections:

- Non-bypassable charges (860-038-0170)
- Preferential Curtailment (860-038-0290)
- HB 2021 utility and ESS labeling requirements (860-038-0300)
- ESS Emissions Planning Report (860-038-0405)
- Nondiscriminatory access to transmission and distribution (860-038-0590(3))

Staff has also included guidance for DA program caps outside of rules on pages eight through nine.

Non-Bypassable Charges

The proposed rule language contains modifications from multiple parties and Staff that represent greater consensus on the definition and criteria for non-bypassable charges. The definition now states that "Non-Bypassable Charges are costs that are directed by the legislature to be recovered by all customers or charges that retail consumers served by electricity service suppliers otherwise may avoid by obtaining electric power through Direct Access that are determined by the Commission to be appropriate for recovery from all customers." A list of non-bypassable charges will still be developed in the contested phase.

NIPPC expressed desire for clarification in section (2), outlining concerns that the rule could imply that DA customers would pay for charges that are not "similarly borne by utility bundled service customers."[6] While it is correct that this rule only refers to DA customers, Staff does not intend for the Division 038 rules to create non-bypassable charges that are not similarly paid by utility customers. Staff notes that the Division 038 rules are specific to Direct Access in Oregon. Therefore, they are written in the context of DA customers. The criteria in subsection (1)(a)-(e) provides context in how charges are determined and reads as if all other utility customers are also paying the same charges. Additionally, the definition of "Non-bypassable Charges" in section (1) mentions "costs…recovered by all customers" which implies that DA customers are paying the same charges in a similar manner as other utility customers. The method of collecting and paying such charges is not outlined in this rule language and will require further determination in the contested phase. Staff does not view this language as precluding any specific collection method for non-bypassable charges, such as a surcharge, which NIPPC has previously proposed.

QTS expressed concern with section (2), requesting that a differentiation between Long-Term Direct Access (LTDA) and New Load Direct Access (NLDA) customers be included so as not to preclude the Commission from making different determinations for those customer segments.[7] Staff believes that the criterion in subsection (1)(c) and possibly other subsections can provide guidance in determining whether charges should be applied differently between these customer classes. Additionally, section (2) states that Non-Bypassable Charges must be paid by DA customers "as determined by the Commission" which provides for Commission discretion on this issue. Staff does not view this language as preventing the Commission from making determinations on NLDA and LTDA eligibility for certain charges, which can be examined further in the contested phase.

PGE and PAC raised concerns with subsection (1)(e), claiming that designating a charge as non-bypassable "in order to establish fair, just, and reasonable rates" does not necessarily protect against unwarranted cost shifting in this context.[8,9] Staff addressed this concern in the straw proposal, citing ORS 757.607 which states that "The Commission is charged both with establishing just, fair, and reasonable rates and preventing unwarranted shifting of costs to non-DA customers." For clarity, Staff has

[6] Docket No. AR 651, NIPPC Comments on Staff Straw Proposal, at 2, (September 15, 2022).
[7] Docket No. AR 651, QTS Comments on Staff Straw Proposal, at 1, (September 15, 2022).
[8] Docket No. AR 651, PGE Comments on Staff Straw Proposal, at 2, (September 15, 2022).
[9] Docket No. AR 651, PacifiCorp Comments on Staff Straw Proposal, at 7, (September 15, 2022).

added "and prevent unwarranted cost shifting" to subsection (1)(e) to align with the statute and address cost shifts in this context.

Lastly, Staff has clarified the language in the definition of an Uneconomic Cost of Implementing a Public Policy Goal on page 18 of Attachment A by removing the word "through" after the word "avoided":

> (73) "Uneconomic Cost of Implementing a Public Policy Goal" means the difference between the cost of implementing the public policy goal and the regulated costs that are avoided as a result of implementing the public policy goal.

Provider of Last Resort and Preferential Curtailment

Staff believes that preferential curtailment provides a workable option in many circumstances. Given the state of the energy industry and the difficulties IOUs will face implementing a reliable and just energy transition for cost-of-service customers, Staff believes that it is reasonable to adopt policies that encourage DA customers and ESSs to be responsible for their own reliability and lean into the efficiency and innovation that retail choice is supposed to capture. In Docket No. UM 2143, Staff plans to recommend requirements for an ESS to demonstrate resource adequacy (RA) through participation in a binding regional or state program. With this framework, Staff believes that enabling preferential curtailment better balances reliability and efficiency than relying on the IOU to acquire duplicative capacity resources in case a DA customer returns. Staff has included draft rules under OAR 860-038-0290 that direct the following:[10]

- IOUs will be able to preferentially curtail DA customers who return when their ESS cannot or will not serve them.
- An IOU must use any available market purchases or excess generation first before curtailing a customer.
- An IOU will collect a charge from the DA customer for the system upgrades if required to enable preferential curtailment.
- An IOU will not preferentially curtail if it is infeasible from a cost, engineering, or system reliability standpoint.
- In the scenario where curtailment is infeasible, the IOU will collect charges from the non-curtailable customer to invest in capacity for their potential return in a default event.

As noted in Staff's straw proposal, Staff believes that utilities can operationalize preferential curtailment given the curtailment requirements for qualifying facilities (QFs), the capabilities of demand response pilots like PGE's Dispatchable Standby Generation, and the deployment of significant distribution automation investments

[10] For the official recommended rules, see Attachment A, OAR 860-038-0290.

described in distribution system planning. Staff also sees preferential curtailment in POLR scenarios as consistent with the treatment of natural gas transport customers as outlined in Northwest Natural Gas Company's General Rules and Regulations, Rule 13.[11]

PGE and PAC raised multiple concerns and questions in response to Staff's proposal, [12] and requested an additional workshop and processes to discuss the preferential curtailment rules. Staff believes that many of the questions that PAC and PGE pose, especially the questions about defining specific terms, can be more effectively decided in the contested case phase where supporting evidence about the costs and system constraints can be evaluated. Staff appreciates the feedback from PGE and PAC that focuses on more detailed aspects of these rules. However, Staff believes that this language provides a general policy framework at this stage that can be refined with the necessary technical details in a contested case.

NIPPC and Brookfield questioned whether the rules would limit a customer from avoiding curtailment by taking service from another ESS if their primary ESS cannot serve their load. Staff does not believe this is a viable option in all potential POLR situations and thus curtailment or backstop capacity would still be required to fully mitigate risk to the system.

NIPPC also identified that the term "transition charge" is already defined in the Division 038 rules and therefore conflicts with Staff's rule in section (4). Staff has removed "transition charge" from the language and added NIPPC's suggestion, "reasonable charge." The set of factors that determine whether a charge is "reasonable" can be further defined via Commission order in future processes.

If it is infeasible to preferentially curtail a customer, NIPPC recommended that a DA customer demonstrating resource adequacy should not be subject to a charge for utility capacity investment. Staff has not included this revision, as the function of a day-ahead RA program may not mitigate all risks associated with a returning customer in some circumstances.

Staff's final edit is the removal of the term "transmission system upgrades" from section (4), as Staff agrees with NIPPC that it is likely that any upgrades required for curtailment would be at the distribution level and not the transmission level.[13] The rule now only refers to "system upgrades".

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[11] NWN General Rules and Regulations, Rule 13.
[12] Docket No. AR 651, PGE Comments on Staff Straw Proposal, at 2-5, (September 15, 2022); Docket No. AR 651, PacifiCorp Comments on Staff Straw Proposal, at 1-7, (September 15, 2022).
[13] Id.

AWEC generally stated support for the idea of preferential curtailment but opposed Staff's proposal that the DA customer shall pay a charge for any necessary distribution system upgrades to operationalize curtailment. Staff maintains that if the DA customer is not responsible for those costs it would inappropriately shift costs onto other retail customers. Therefore, Staff continues to recommend that section (4) is included in the rule language. AWEC does propose an alternative curtailment strategy, where customers must self-curtail or face significant financial penalties.[14] This would not require the installation of system upgrades but Staff has concerns that it would still result in potential risk to the system and may not be applicable in all potential POLR situations. However, Staff believes that the current language does not expressly prohibit contractual curtailment if deemed appropriate in the contested phase.

Please note that in OAR 860-038-0590-3, Staff has included an exclusionary phrase to indicate that the requirements of Section 0590 do not apply in the instance of preferential curtailment. Staff believes this modification is required since the concept of knowingly curtailing one customer over another directly contradicts Section 0590's designation for non-discriminatory access to transmission and distribution for all retail customers.

Utility and ESS Labeling Requirements
Staff included language directed by HB 2021 stating that "an electricity service provider must post a summary for the aggregated energy supply mix and associated emissions for the Direct Access load served in Oregon in the previous year." Parties generally agreed with this inclusion and Staff's view that some transparency still needs to exist by enforcing existing indicative pricing rules for an ESS. Staff notes the existing rule requires ESSs and utilities to provide a website to the Commission where they regularly post indicative pricing. This would also apply to posting the summary of an aggregated energy supply mix and will be enforced in the same manner. NIPPC and Brookfield suggested that the Commission specifies a date for compliance with this requirement in September or November of a given year. Staff has included that an ESS must post the summaries on November 15 to align with the posting date for indicative pricing.

ESS Emission Planning Report
Staff included additional language specifying which parties have access to confidential information via a modified protective order. Variations of this language were developed by NIPPC, CUB, and the environmental NGOs, and Staff believes the final product clarifies the review and engagement process while providing the necessary protections for ESS's competitive information. PAC raised concerns with these additions, stating that it is unclear how the utilities can verify remittance payments from the ESS under the

[14] Docket No. AR 651, AWEC Comments on Staff Straw Proposal, at 3, (September 15, 2022).

rules.[15] Staff notes that these rules apply specifically to the ESS Emission Planning Reports and were not intended to regulate the methods of verifying ESS remittance to the utilities. Due to this specificity, the rules do not appear to preclude any verification or auditing methods for remittances, which are a separate issue outside the scope of this rulemaking.

PAC and PGE both expressed that the reports should be held to the same standard of public scrutiny as the utilities' Clean Energy Plans (CEP) discussed in Docket No. UM 2225. Staff does not interpret this rule language to hinder public engagement or transparency, rather, that it provides a clear path for parties to have access to information for verifying compliance and trajectory. To the extent possible, Staff will continue to engage in discussions on this topic in conjunction with the progression of CEP requirements in UM 2225.

PGE, PAC, and the environmental NGOs continue to express concern with the initial reporting date not beginning until 2027 and the lack of time to evaluate continual and reasonable progress leading up to 2030.[16] Staff reiterates that the interpretation of HB 2021 and the nature of ESS' resource planning may create administrative process for ESS's and the Commission, but not result in a meaningful forward-looking reporting framework. Section 5(3)(a) of HB 2021 indicates a three-year forward estimate of emissions be included in the ESS compliance plans. Staff interprets the statute to mean that the three-year estimates should be projecting out to the time of compliance obligations. Therefore, an earlier reporting date than 2027 would show an incomplete trajectory toward the first compliance period and would require information that is not required by statute.

Staff proposed an alternative solution in which reporting covers more than a three-year outlook and begins earlier. However, Staff did not receive support for this proposal.

Direct Access Caps and Behind-The-Meter (BTM) Load Growth
Acknowledging the difficulty of proposing rule language on caps without supposing their existence, Staff includes the following criteria outside of rules to guide future Commission decisions about whether a program cap itself, or an expansion above a cap, is acceptable.

[15] Docket No. AR 651, PacifiCorp Comments on Staff Straw Proposal, at 9, (September 15, 2022).
[16] ORS 469A.420 (3)(d) requires the Commission to review this report to determine, "whether the electricity service supplier is making continual and reasonable progress toward compliance with the clean energy targets."

The Commission may preserve, adjust, or impose a cap if an increase in DA load will:

- Compromise system reliability
- Shift an unacceptable amount of cost to cost-of-service customers
- Pose undesirable long term financial impacts to the electric system or cost-of-service customers
- Pose other unmitigated risks to cost-of-service customers

Parties generally were agreeable to the above criteria but requested some reframing. PGE, for example, recommended that the party requesting the expansion or removal of a cap has the burden of proof to demonstrate that no unwarranted cost shifting, or reliability impacts will occur.[17] Staff continues to recommend the above wording under the assumption that it is more straightforward to prove that cost shifts and risks exist rather than prove they do not. AWEC opposed including this guidance for DA caps in rule but agrees with Staff that it is an appropriate policy position to guide contested case arguments.

Staff believes that its identified criteria are similarly applicable to BTM load growth. If cost shifting, risk, and reliability concerns can be addressed through transition charges or resource adequacy, load growth could be accommodated without posing significant risk.

In the event that DA caps are deemed necessary in the contested case, Staff continues to support its original policy positions that recalculating caps at a regular interval would be necessary to account for shifting risk and load growth. Additionally, any petition to exceed a cap should follow a time-limited process open to all intervenors. Staff looks forward to further exploring these issues in the contested case phase.

<u>Conclusion</u>

Staff has engaged in a collaborative process to identify draft rules that reflect key policy principles for contemporary Direct Access issues. Staff recommends that the Commission Adopt Staff’s recommendation on Direct Access caps and accept Staff’s proposed OAR Chapter 860, Division 038 rules and move the AR 651 Direct Access Rulemaking to the formal stage.

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[17] Docket No. AR 651, PGE Comments on Staff Straw Proposal, at 7-8, (September 15, 2022).

PROPOSED COMMISSION MOTION:

Adopt Staff's policy guidance on Direct Access caps, open a formal rulemaking on Direct Access, and issue a notice of proposed rulemaking to amend and adopt Division 038 rules as included in Attachment A.

Docket No. AR 651

Attachment A: Revised Division 38 Direct Access Regulation

860-038-0001

Scope and Applicability of Rules

(1) The rules contained in this division apply to electric companies and electricity service suppliers, except that these rules do not apply to an electric company serving fewer than 25,000 consumers in this state unless the electric company:

(a) Offers direct access to any of its retail electricity consumers in this state; or

(b) Offers to sell electricity services available under direct access to more than one retail electricity consumer of another electric company in this state.

(2) Except as otherwise provided in these rules, an electric company must comply with all other divisions of OAR chapter 860.

(3) OAR 860-038-0380, sections (1) through (9), apply to aggregators; section (10) applies to electric companies.

(4) These rules shall not in any way relieve any entity from its duties under Oregon law. Upon request or its own motion, the Commission may waive any of the Division 038 rules for good cause shown. A request for waiver must be made in writing, unless otherwise allowed by the Commission.

860-038-0005

Definitions for Direct Access Regulation

As used in this Division:

(1) "Above-market costs of new renewable energy resources" means the portion of the net present value cost of producing power (including fixed and operating costs, delivery, overhead, and profit) from a new renewable energy resource that exceeds the market value of an equivalent quantity and distribution (across peak and off-peak periods and seasonality) of power from a nondifferentiated source, with the same term of contract.

(2) "Portfolio Options Committee" means a group appointed by the Commission, consisting of representatives from Commission Staff, the Oregon Department of Energy, and the following:

(a) Local governments;

(b) Electric companies;

(c) Residential consumers;

(d) Public or regional interest groups; and

(e) Small nonresidential consumers.

(3) "Affiliate" means a corporation or person who has an affiliated interest, as defined in ORS 757.015, with a public utility.

(4) "Aggregate" means combining retail electricity consumers into a buying group for the purchase of electricity and related services. "Aggregator" means an entity that aggregates.

(5) "Ancillary services" means those services necessary or incidental to the transmission and delivery of electricity from resources to retail electricity consumers, including but not limited to scheduling, frequency regulation, load shaping, load following, spinning reserves, supplemental reserves, reactive power, voltage control and energy balancing services.

(6) "Commission" means the Public Utility Commission of Oregon.

(7) "Common costs" means costs that cannot be directly assigned to a particular function.

(8) "Competitive operations" means any electric company's activities involving the sale or marketing of electricity services or directly related products in an Oregon retail market. Competitive operations include, but are not limited to, the following:

(a) Energy efficiency audits and programs;

(b) Sales, installation, management, and maintenance of electrical equipment that is used to provide generation, transmission, and distribution related services or enhances the reliability of such services; and

(c) Energy management services, including those services related to electricity metering and billing. Services or products provided by the electric company as part of its electric service to its non-direct access customers within its allocated service territory, or transmission and distribution services to its direct access customers are not competitive operations.

(9) "Constructing and operating," as used in ORS 757.612(3)(b)(B), means constructing, or operating, or both.

(a) As used in ORS 757.612(3)(b)(B), "constructing" includes the following activities:

(A) Pre-development project studies, activities or costs that are related to the planned development of a new renewable energy resource that a developer or owner would reasonably expect to incur; and

(B) Activities or costs directly related to the building of a new renewable energy resource.

(b) As used in ORS 757.612(3)(b)(B), "operating" includes the activities and costs necessary for a new renewable energy resource to function and to be maintained in good working order.

(10) "Consumer-owned utility" means a municipal electric utility, a people's utility district, or an electric cooperative.

(11) "Cost-of-service consumer" means a retail electricity consumer who is eligible for a cost-of-service rate under ORS 757.603.

(12) "Default supplier" means an electric company that has a legal obligation to provide electricity services to a consumer, as determined by the Commission.

(13) "Direct access" means the ability of a retail electricity consumer to purchase electricity and certain ancillary services directly from an entity other than the distribution utility.

(14) "Direct service industrial consumer" means an end-user of electricity that obtains electricity directly from the transmission grid and not through a distribution utility.

(15) "Distribution" means the delivery of electricity to retail electricity consumers through a distribution system consisting of local area power poles, transformers, conductors, meters, substations and other equipment.

(16) "Distribution utility" means an electric utility that owns and operates a distribution system connecting the transmission grid to the retail electricity consumer.

(17) "Divestiture" means the sale of all or a portion of an electric company's ownership share of a generation asset to a third party.

(18) "Economic utility investment" means all Oregon allocated investments made by an electric company that offers direct access under ORS 757.600 to 757.667, including plants and equipment and contractual or other legal obligations, properly dedicated to generation or conservation, that were prudent at the time the obligations were assumed but the full benefits of which are no longer available to consumers as a direct result of 757.600 to 757.667, absent transition credits. "Economic utility investment" does not include costs or expenses disallowed by the Commission in a prudence review or other proceeding, to the extent of such disallowance, and does not include fines or penalties authorized and imposed under state or federal law.

(19) "Electric company" means an entity engaged in the business of distributing electricity to retail electricity consumers in this state but does not include a consumer-owned utility.

(20) "Electric company operational information" means information obtained by an electric company as part of its provision of services or products, as long as such products or services are not defined as "competitive operations." Such information includes, but is not limited to, data relating to the interconnection of customers to an electric company's transmission or distribution systems; trade secrets; competitive information relating to internal processes; market analysis reports; market forecasts; and information about an electric company's transmission or distribution system, processes, operations, or plans or strategies for expansion.

(21) "Electric cooperative" means an electric cooperative corporation organized under ORS Chapter 62 or under the laws of another state if the service territory of the electric cooperative includes a portion of this state.

(22) "Electric utility" means an electric company or consumer-owned utility that is engaged in the business of distributing electricity to retail electricity consumers in this state.

(23) "Electricity" means electric energy, measured in kilowatt-hours, or electric capacity, measured in kilowatts, or both.

(24) "Electricity services" means electricity distribution, transmission, generation, or generation-related services.

(25) "Electricity service supplier" or "ESS" means a person or entity that offers to sell electricity services available pursuant to direct access to more than one retail electricity consumer. "Electricity service supplier" does not include an electric utility selling electricity to retail electricity consumers in its own service territory. An ESS can also be an aggregator.

(26) "Emergency default service" means a service option provided by an electric company to a nonresidential consumer that requires less than five business days' notice by the consumer or its electricity service supplier.

(27) "Fully distributed cost" means the cost of an electric company good or service calculated in accordance with the procedures set forth in OAR 860-038-0200.

(28) "Functional separation" means separating the costs of the electric company's business functions and recording the results within its accounting records, including allocation of common costs.

(29) "Joint marketing" means the offering (including marketing, promotion, or advertising) of retail electric services by an electric company in conjunction with its competitive operation to consumers either through contact initiated by the electric company, its Oregon affiliate, or through contact initiated by the consumer.

(30) "Large nonresidential consumer" means a nonresidential consumer whose kW demand at any point of delivery is greater than 30 kW during any two months within a prior 13-month period.

(31) "Load" means the amount of electricity delivered to or required by a retail electricity consumer at a specific point of delivery.

(32) "Local energy conservation" means conservation measures, projects, or programs that are installed or implemented within the service territory of an electric company.

(33) "Low-income weatherization" means repairs, weatherization, and installation of energy efficient appliances and fixtures for low-income residences for the purpose of enhancing energy efficiency.

(34) "Market transformation" means a lasting structural or behavioral change in the marketplace that increases the adoption of energy efficient technologies and practices.

(35) "Multi-state electric company" means an electric company that provided regulated retail electric service in a state in addition to Oregon prior to January 1, 2000.

(36) "Municipal electric utility" means an electric distribution utility owned and operated by or on behalf of a city.

(37) "New" as it refers to energy conservation, market transformation, and low-income weatherization means measures, projects or programs that are installed or implemented after the date direct access is offered by an electric company.

(38) "New renewable energy resource," as used in ORS 757.612(3)(b)(B), has the meaning provided in 757.600(21) and references a specifically identified project that has, or is planned to have after construction, a nominal electric generating capacity, as defined in 469.300, of 20 megawatts or less.

(39) "Non-energy attributes" means the environmental, economic, and social benefits of generation from renewable energy facilities. These attributes are normally transacted in the form of Tradable Renewable Certificates.

(40) "Nonresidential consumer" means a retail electricity consumer who is not a residential consumer.

(41) "Ongoing valuation" means the process of determining transition costs or benefits for a generation asset by comparing the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period.

(42) "One-time administrative valuation" means the process of determining the market value of a generation asset over the life of the asset, or a period as established by the Commission, using a process other than divestiture.

(43) "One average megawatt" means 8,760,000 kilowatt-hours (8,784,000 in a leap year) of electricity per twelve consecutive month period.

(44) "Oregon affiliate" means an affiliate engaged in the sale or marketing of electricity services or directly related products in an Oregon retail market.

(45) "Oregon share" means, for a multi-state electric company, an interstate allocation based upon a fixed allocation or method of allocation established in a Resource Plan or, in the case of an electric company that is not a multi-state electric company, 100 percent.

(46) "People's utility district" has the meaning given that term in ORS 261.010.

(47) "Portfolio" means a set of product and pricing options for electricity.

(48) "Proprietary consumer information" means any information compiled by an electric company on a consumer in the normal course of providing electric service that makes possible the identification of any individual consumer by matching such information with the consumer's name, address, account number, type or classification of service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing records, or any other information that the consumer has expressly requested not be disclosed. Information that is redacted or organized in such a way as to make it impossible to identify the consumer to whom the information relates does not constitute proprietary consumer information.

(49) "Qualifying expenditures" means those expenditures for energy conservation measures that have a simple payback period of not less than one year and not more than 10 years and expenditures for the

above-market costs of new renewable energy resources, provided that the Oregon Department of Energy may establish by rule a limit on the maximum above-market cost for renewable energy that is allowed as a credit.

(50) "Registered dispute" means an unresolved issue affecting a retail electricity consumer, an ESS, or an electric company that is under investigation by the Commission's Consumer Services Section but is not the subject of a formal complaint.

(51) "Regulated charges" means charges for services subject to the jurisdiction of the Commission.

(52) "Regulatory assets" means assets that result from rate actions of regulatory agencies.

(53) "Renewable energy resources" means:

(a) Electricity-generation facilities fueled by wind, waste, solar or geothermal power, or by low-emission nontoxic biomass based on solid organic fuels from wood, forest, and field residues;

(b) Dedicated energy crops available on a renewable basis;

(c) Landfill gas and digester gas; and

(d) Hydroelectric facilities located outside protected areas as defined by federal law in effect on July 23, 1999.

(54) "Residential consumer" means a retail electricity consumer that resides at a dwelling primarily used for residential purposes. "Residential consumer" does not include retail electricity consumers in a dwelling typically used for residency periods of less than 30 days, including hotels, motels, camps, lodges, and clubs. As used in this section, "dwelling" includes but is not limited to single-family dwellings, separately metered apartments, adult foster homes, manufactured dwellings, recreational vehicles, and floating homes.

(55) "Retail electricity consumer" means the end user of electricity for specific purposes such as heating, lighting, or operating equipment and includes all end users of electricity served through the distribution system of an electric utility on or after July 23, 1999, whether or not each end user purchases the electricity from the electric utility. For purposes of this definition, a new retail electricity consumer means a retail electricity consumer that is unaffiliated with the retail electricity consumer previously served after March 1, 2002, at the site.

(56) "Self-directing consumer" means a retail electricity consumer that has used more than one average megawatt of electricity at any one site in the prior calendar year or an aluminum plant that averages more than 100 average megawatts of electricity use in the prior calendar year, that has received final certification from the Oregon Department of Energy for expenditures for new energy conservation or new renewable energy resources and that has notified the electric company that it will pay the public purpose charge, net of credits, directly to the electric company in accordance with the terms of the electric company's tariff regarding public purpose credits.

(57) "Serious injury to person" has the meaning given in OAR 860-024-0050.

(58) "Serious injury to property" has the meaning given in OAR 860-024-0050.

(59) "Site" means:

(a) Buildings and related structures that are interconnected by facilities owned by a single retail electricity consumer and that are served through a single electric meter; or

(b) A single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, such that:

(A) Each building or structure included in the site is no more than 1,000 feet from at least one other building or structure in the site;

(B) Buildings and structures in the site, and land containing and connecting buildings and structures in the site, are owned by a single retail electricity consumer who is billed for electricity use at the buildings and structures; and

(C) Land shall be considered to be contiguous even if there is an intervening public or railroad right of way, provided that rights of way land on which municipal infrastructure facilities exist (such as street lighting, sewerage transmission, and roadway controls) shall not be considered contiguous.

(60) "Small nonresidential consumer" means a nonresidential consumer that is not a large nonresidential consumer.

(61) "Special contract" means a rate agreement that is justified primarily by price competition or service alternatives available to a retail electricity consumer, as authorized by the Commission under ORS 757.230.

(62) "Structural separation" means separating the electric company's assets by transferring assets to an affiliated interest of the electric company.

(63) "Total transition amount" means the sum of an electric company's transition costs and transition benefits.

(64) "Traditional allocation methods" means, in respect to a multi-state electric company, inter-jurisdictional cost and revenue allocation methods relied upon in such electric company's last Oregon rate proceeding completed prior to December 31, 2000.

(65) "Transition benefits" means the value of the below-market costs of an economic utility investment.

(66) "Transition charge" means a charge or fee that recovers all or a portion of an uneconomic utility investment.

(67) "Transition costs" means the value of the above-market costs of an uneconomic utility investment.

(68) "Transition credit" means a credit that returns to consumers all or a portion of the benefits from an economic utility investment.

(69) "Transmission grid" means the interconnected electrical system that transmits energy from generating sources to distribution systems and direct service industries.

(70) "Unbundling" means the process of assigning and allocating a utility's costs into functional categories.

(71) "Uneconomic utility investment" means all Oregon allocated investments made by an electric company that offers direct access under ORS 757.600 to 757.667, including plants and equipment and contractual or other legal obligations, properly dedicated to generation, conservation and work-force commitments, that were prudent at the time the obligations were assumed but the full costs of which are no longer recoverable as a direct result of 757.600 to 757.667, absent transition charges. "Uneconomic utility investment" does not include costs or expenses disallowed by the Commission in a prudence review or other proceeding, to the extent of such disallowance and does not include fines or penalties as authorized by state or federal law.

(72) “Unspecified Market Purchase Mix” means the mix of all power generation within the state or other region less all specific purchases from generation facilities in the state or region, as determined by the Oregon Department of Energy.

(73) “Uneconomic Cost of Implementing a Public Policy Goal” means the difference between the cost of implementing the public policy goal and the regulated costs that are avoided as a result of implementing the public policy goal.

860-038-0080
Resource Policies and Plans

(1) The Commission adopts the following policies with respect to the Oregon share of generating resources (generating assets and power purchase contracts with a duration of at least one year) of each electric company:

(a) At such time as the Resource Plan is implemented and fully executed, each electric company will retain in its Oregon revenue requirement costs associated with a level of generating resources that is not greater than that necessary to meet the current and reasonably expected future loads of its Oregon cost-of-service consumers. In determining whether an electric company has excess generating resources, the Commission will consider the projected useful lives and mix of fuels of the electric company's generating resources. To encourage the development of a competitive retail energy market, it is the policy of the Commission to release to the competitive market generating resources in excess of such reasonably expected future loads. It is also the policy of the Commission to determine a one-time valuation for the share of an electric company's generating resources attributable to Oregon consumers who are not cost-of-service consumers;

(b) The Commission will not require an electric company to acquire new generating resources except as provided in ORS 757.663.

(c) Major capital improvements to existing generating resources will continue to be, and new generating resources will be, subject to least cost planning processes and analyses and the Oregon share of their prudently-incurred costs will be included in an electric company's Oregon revenue requirement, which for a multi-state electric company shall be consistent with Commission decisions pursuant to subsection (3)(a)(G) of this rule.

(d) The Oregon share of the costs of each generating resource may be either completely in, completely out, or "mixed" with respect to inclusion in an electric company's Oregon revenue requirement. The Commission will permit mixed status unless it finds that mixed status will:

(A) Reduce the generating resource's operating efficiency;

(B) Harm the development of a competitive market; and

(C) Prevent the owners from making economic decisions about the operation of the generating resource.

(e) For a multi-state electric company for which the Commission adopts a fixed-allocated Oregon share amount, and a Resource Plan is implemented, such generating allocation amount will be used for developing cost-of-service rates, transition charges and credits, and Operations and Maintenance allocations as well as other allocations that use generation-based factors.

(2) For purposes of this rule and OARs 860-038-0100 and 860-038-0140, a class's share of the total Oregon share of a generating resource will equal the ratio of the class's total Oregon retail load measured in weather-normalized kilowatt-hour sales to total Oregon retail load measured in weather-normalized kilowatt-hour sales for a 12 month period as determined by the Commission. Loads will be adjusted to remove the effects of demand exchange programs that were in effect during the 12 month period. To the extent such shares are not known as of the time period established by the Commission, the electric company will use estimates until relevant data are available.

(3) By a date to be determined by the Commission, each electric company must file with the Commission a resource plan that meets the following requirements:

(a) Information. The resource plan must include the following information:

(A) Consistent with paragraph subsection (3)(a)(G) of this rule, the amount of capacity and energy and the availability of each generating resource that is attributable to the share of the electric company's load from cost-of-service consumers, and the amount that is attributable to the share of the electric company's load from consumers not eligible for a cost-of-service rate;

(B) A forecast of the revenue requirements associated with each generating resource over both its projected remaining useful life and economic life, with sensitivities for major assumptions, and identification of deferred taxes, excess deferred taxes, FASB 109 assets, and any investment tax credits associated with each generating resource;

(C) The other characteristics of the generating resource that could affect its value including but not limited to its capability to provide or support ancillary services, the value of its site and environmental or operating permits, and any environmental issues associated with it;

(D) A forecast of future market prices for electricity, including forecasts of major fuel inputs and sensitivity analyses;

(E) A forecast of loads of the electric company's Oregon cost-of-service consumers covering at least the period of the longest-lived generating resource;

(F) The estimated fair market value of the Oregon share of each generating resource; and

(G) For a multi-state electric company, how the electric company proposes to allocate a share of its generating resources to Oregon. The multi-state electric company must also propose a fixed Oregon-allocated generating resource share based on the following factors:

(i) A forecasted allocation of each generating resource for a 12 month period as determined by the Commission, using traditional allocation methods recognized by the Commission;

(ii) The projected potential changes in Oregon share, due to alternative inter-jurisdictional allocation methods, over the life of each resource absent implementation of these rules; and

(iii) The change in risk borne by parties by fixing the Oregon share of generating resource.

(b) Recommended Valuation Methodology. The resource plan must identify, for each generating resource, or portion thereof if the resource meets the criteria for mixed status, whether the Oregon share of each generating resource should be:

(A) Retained in the electric company's Oregon revenue requirement for the purpose of serving Oregon cost-of-service consumers and administratively valued through a process to be specified by rule;

(B) Sold through the auction process specified in OAR 860-038-0100, and if so:

(i) The general terms and conditions that should apply to the sale, including but not limited to, a prototype purchase and sale agreement; and

(ii) Any sales incentives that the electric company proposes to apply to Oregon nonresidential consumers for the Oregon nonresidential consumers' share of the generating resource. Such incentives may be structured to encourage the electric company to follow the recommended timeline provided under subsection (3)(d) of this rule; or

(C) Removed from the electric company's Oregon revenue requirement and administratively valued through a process to be specified by rule, and if so, any incentive to apply to Oregon nonresidential consumers for removing the nonresidential consumers' share of the generating resource from revenue requirement. Such incentives may be structured to encourage the electric company to follow the recommended timeline provided under subsection (3)(d) of this rule.

(c) Results of the Resource Plan. The resource plan must identify the impacts of implementing it, including the following:

(A) The approximate load/resource balance, and the availability of each generating resource based on the electric company's current and forecasted load for Oregon cost-of-service consumers;

(B) The estimated rates to each Oregon customer class that will result from implementation of the resource plan, including:

(i) The amount of estimated transition charges and credits;

(ii) A comparison to the current effective rates of the electric company as of the date of filing; and

(iii) An estimate of the cost-of-service rates for cost-of-service consumers 10 years after implementation of the resource plan.

(C) How the resource plan is consistent with the purposes of SB 1149 in that the plan:

(i) Facilitates a fully competitive market;

(ii) Provides consumers fair, non-discriminatory access to competitive markets; and

(iii) Retains the benefits of low-cost resources for consumers.

(D) Any other implications of the resource plan that could help inform the Commissioners in their decision.

(d) Process. The electric company must develop the resource plan in a public process designed to inform and solicit input from Commission staff, representatives of Oregon residential, small nonresidential and large nonresidential consumers, and other interested parties.

(4) The Commission must consider the electric company's recommended resource plan in a contested case proceeding. The Commission's order must identify those resources that, at the option of the electric company, may be auctioned immediately, before any Commission decision to waive the requirements for a cost-of-service rate for any consumers under ORS 757.603(1)(b) and before final administrative valuation of other resources and potential modification of the electric company's Resource Plan. The Commission's order must also approve, modify, or reject the resource plan.

(a) If the Commission modifies the resource plan, the electric company will have 30 days from the date of the Commission's order to accept or reject the modifications. If the electric company rejects the Commission's modifications, the electric company must file a second recommended resource plan within 60 days of the date of rejection;

(b) If the Commission rejects the resource plan, the order rejecting the plan must specifically describe the deficiencies in the resource plan. In that event, the electric company must file a second recommended resource plan within 60 days of the order rejecting the original plan;

(c) If the Commission modifies the second recommended resource plan, the electric company will have 30 days from the date of the order to accept or reject the modifications. If the electric company rejects the Commission's modifications, future attempts at reaching a resource plan may be initiated by either the electric company or the Commission. The timelines outlined in subsection (4)(a) of this rule shall apply once a new resource plan is submitted or modifications to a former plan are suggested.

(5) A resource plan that has been recommended by the electric company and approved by the Commission, or modified by the Commission and accepted by the electric company, is referred to in these rules as a "Resource Plan." The Resource Plan may encompass one plan or a set of plan options corresponding to different assumptions about consumer eligibility for cost-of-service rates. The electric company must implement the Resource Plan consistent with OAR 860-038-0100 and a process for administrative valuation to be specified by rule. The ongoing valuation method, as described in 860-038-0140, will be used to establish transition charges and credits for resources that have not been sold or administratively valued.

(6) For a multi-state electric company, pending the implementation of a Resource Plan and establishing final values for generating resources in accordance with these rules, the following will guide developing rates for Oregon consumers of the electric company for the period March 1, 2002, through December 31, 2003:

(a) Cost-of-service rates will be based upon traditional allocation methods;

(b) Transition charges or credits shall not include assumed costs and revenues of the portion of generating resources not needed to serve Oregon loads associated with residential and small nonresidential consumers choosing portfolio access, small nonresidential consumers choosing direct access or standard offer rate options, and large nonresidential consumers when, and to the extent, the costs and revenues of the generating resources that are not needed are recognized and included in the electric company's revenue requirement in another state, less the costs and revenues of such generating resources which have been included in the electric company's revenue requirement by another state prior to October 1, 2001; and

(c) Beginning January 1, 2004, transition charges and transition credits will be calculated without regard to subsection (7)(b) of this rule.

860-038-0100
Auction Process

(1) Each electric company must follow the process provided in sections (2) and (3) of this rule for all generating resources, or portions thereof, that it intends to sell pursuant to the Resource Plan, unless it presents to the Commission, and the Commission approves, an alternative process.

(2) The auction process will be the process adopted by the Commission in Order No. 99-765, except that affiliates of the electric company may participate in the auction as eligible buyers, in which case the auction will be subject to such requirements to assure independent decision making as the Commission may determine.

(3) Unless otherwise provided in the Resource Plan, the electric company shall not begin its auction process until the Commission issues a final order valuing all of the electric company’s Oregon share of generating resources pursuant to a process to be established by rule.

(4) Notwithstanding section (3) of this rule, the electric company may, at its option, immediately auction all or a portion of generating resources identified by the Commission as exempt from section (3) of this rule. Any such auction will be subject to ORS 757.480 and OAR 860-027-0025.

(5) The electric company shall recover through the transition balancing account the costs of an auction process, including but not limited to the reasonable costs of investment bankers and other advisors.

860-038-0140
Ongoing Valuation

(1) An electric company may use an ongoing valuation method to determine the transition costs or transition credits applicable to Oregon cost-of-service consumers until otherwise directed by the Commission. Except in the circumstances set forth in OAR 860-038-0080(5) and (6), an electric company will use an ongoing valuation method to determine the transition charges or transition credits applicable to Oregon cost-of-service consumers.

(2) Each electric company will propose one or more ongoing valuation methods in the rate filings. Each method must, at a minimum, address:

(a) How and over what period the electric company proposes to establish the fixed costs of included generating resources;

(b) How and over what period the electric company proposes to establish the variable costs of included generating resources;

(c) How and over what period the electric company proposes to establish the availability and output of included generating resources;

(d) How and over what period the electric company proposes to establish the market value of the output of included generating resources; and

(e) How and when revisions should be made in the method.

(3) An electric company may propose to include in its tariffs expedited procedures, which shall include an opportunity for public comment, for determining the costs and value of an electric company's generating resources for purposes of determining transition charges and credits applicable under this rule.

860-038-0160
Transition Costs and Credits

(1) Except as provided for in OAR 860-038-0080(6), each Oregon retail electricity consumer of an electric company will receive a transition credit or pay a transition charge equal to 100 percent of the net value of the Oregon share of all economic utility investments and all uneconomic utility investments of the electric company as determined pursuant to an auction, an administrative valuation, or an ongoing valuation. The transition charge or credit applicable to a retail electricity consumer may change to

reflect the duration of the service option chosen by the consumer but will not change based on the supplier of the electricity services chosen by the consumer.

(2) Once a Resource Plan is implemented, the Oregon cost-of-service consumers of an electric company will bear the entire revenue requirement of generating resources, or portions thereof, retained in that electric company's Oregon revenue requirement for the purpose of serving those Oregon consumers. In addition, the electric company will:

(a) Collect from its Oregon cost-of-service consumers the funds necessary to provide any transition credits related to such resources to its other Oregon consumers exclusive of incentive payments; or

(b) Credit to its Oregon cost-of-service consumers the funds received from any transition charges related to such resources from its other Oregon consumers exclusive of incentive payments.

(3) For purposes of determining transition costs and transition credits:

(a) The value of generating resources determined through an auction conducted pursuant to OAR 860-038-0100 will equal the proceeds of such auction, less any reasonable costs of sale and any tax effects of the sale;

(b) The value applicable to Oregon nonresidential consumers will be reduced for any incentives provided under the Resource Plan;

(c) The net value of generating resources determined through an auction conducted pursuant to OAR 860-038-0100 will equal the Oregon residential and nonresidential respective values of generating resources minus the book value as recorded for regulatory purposes;

(d) The value of generating resources determined through an administrative valuation conducted pursuant to a process to be specified by rule will equal the final valuation inclusive of any tax effects less allowed appraisal costs. The treatment of the tax effects of a potential future sale of an administratively valued asset will be addressed in a future rulemaking;

(e) The value applicable to Oregon nonresidential consumers will be reduced for any incentives provided under the Resource Plan; and

(f) The net value of generating resources determined through an administrative valuation conducted pursuant to a process to be specified by rule will equal the Oregon residential and nonresidential respective values of generating resources minus the book value as recorded for regulatory purposes.

(4) For the Oregon share of:

(a) Economic and uneconomic investments that are not resources;

(b) Other regulatory assets;

(c) Demand side management assets existing as of March 1, 2002; and

(d) Retired or abandoned plant for which the Commission established cost recovery before July 23, 1999, transition costs or benefits will be allocated 100 percent to Oregon retail electricity consumers.

(5) Each electric company must maintain records to properly record and amortize transition costs and transition credits using a transition balancing account. Any unamortized balance in the transition balancing account will accrue interest at the electric company's Oregon authorized cost of capital.

(6) The transition costs or transition benefits allocated to a customer class for a specific time period will be charged or credited to Oregon retail electricity consumers on a weather normalized equal cents per kilowatt-hour basis adjusted for losses. To the extent weather-normalized kilowatt-hour sales are not known, as of March 1, 2002, estimates will be used until relevant data are available.

(7) The Commission will determine the period of payment or recovery of transition costs or transition credits, provided such period will not exceed 10 years.

860-038-0170
Non-bypassable Charges

(1) "Non-bypassable Charges" are costs that are directed by the legislature to be recovered by all customers or charges that retail consumers served by electricity service suppliers otherwise may avoid by obtaining electric power through direct access that are determined by the Commission to be appropriate for recovery from all customers. In determining whether a cost is appropriate for recovery as a non-bypassable charge, the Commission shall consider the following factors:

(a) whether it is required by statute

(b) whether it is an uneconomic cost of implementing a public policy goal such as those identified in ORS 469A.465 or similar public policy goals related to reliability, equity, decarbonization, resiliency or other public interest for which retail consumers served by electricity service suppliers otherwise would not meaningfully contribute.

(c) whether or not it confers a demonstrable electric system benefit on some customers over others

(d) whether it is in the public interest

(e) whether it is necessary to be non-bypassable under the Commission's discretion in order to establish fair, just, and reasonable rates and prevent unwarranted cost shifting.

(2) All retail electricity consumers served by Direct Access ~~are~~ responsible for paying Non-bypassable Charges as determined by the Commission.

860-038-0200
Unbundling

(1) This rule is designed to ensure compliance with ORS 757.642 by directing electric companies to separately identify their embedded costs on a function-by-function basis. The electric company must unbundle its costs in a manner that facilitates the development of rates described in OARs 860-038-0220

to 860-038-0280. The electric company must unbundle costs associated with functions that a retail electricity consumer may self-supply or purchase from an entity other than the electric company. The calculation of unbundled rates is beyond the scope of this rule.

(2) Each electric company must separately identify its costs of each of the following functions:

(a) Generation;

(b) Transmission services;

(c) Distribution services;

(d) Ancillary services;

(e) Consumer services:

(A) Billing services;

(B) Metering services; and

(C) Other consumer services;

(f) Retail services, examples of which are listed in section (3) of this rule;

(g) Investment in public purposes; and

(h) Any other function the Commission deems appropriate.

(3) Examples of Retail Services include but are not limited to the marketing, sale, design, construction, installation or retrofitting, financing, operation and maintenance, warranty and repair of or consulting with respect to:

(a) Energy consuming equipment located on the consumer's premises;

(b) Provision of technical assistance relating to any customer-premises process or device that consumes electricity, including energy audits;

(c) Transformation equipment, power-generation equipment, and related services located on the consumer's premises that are not owned by the electric company;

(d) Building or facility design and related engineering services, including building shell construction, renovation or improvement, or analysis and design of energy-related industrial processes;

(e) Facilities operations and management; and

(f) Other activities identified by the Commission.

(4) Each electric company must separately identify costs as direct or indirect for each function. Costs must be directly assigned where information is available. To the extent possible, all costs must be assigned to the functions based on cost causation. Common costs and taxes allocated to each of these

functions must be separately identified. A return on investment must be calculated and stated separately for each function.

(5) Each electric company must file its functionally unbundled costs with its general rate filings and results of operations reports filed with the Commission. The electric company filing must clearly identify the allocation factor(s) used to functionalize each rate base, expense, and revenue item. All allocation and functionalization procedures adopted by the Commission for an electric company must be used in subsequent filings until expressly modified by the Commission.

(6) Each electric company must make an initial filing complying with the rules in this Division by October 1, 2000. This filing shall use the financial results for a test year that encompasses all or part of the 12-month period beginning October 1, 2001.

(7) Each electric company must use the allocators and cost functionalization procedures set forth in section (9) of this rule to functionally unbundle its respective costs. If an electric company proposes to assign, allocate, or reclassify costs using cost functionalization procedures that differ from those contained herein, the electric company must include in its filing, testimony that:

(a) Supports the allocation factors and procedures the electric company proposes to use to unbundle its costs;

(b) Justifies the deviation from the cost functionalization procedures; and

(c) Presents the results of the allocation factors and procedures set forth in this rule and the results of the alternative factors and procedures that are proposed.

(8) The cost allocation factors in section (7) of this rule are subject to Commission review and approval.

(9) Costs must be directly assigned to the functions identified in section (2) of this rule where information is available. The allocation procedures presented below are to be used to functionalize those costs that cannot otherwise be charged directly to the appropriate function.

(a) Rate Base:

(A) Intangible Plant (FERC Accounts 301-303) must be directly assigned where possible. The remainder of the costs must be allocated to the appropriate functions using the O&M Labor allocator;

(B) Generation Plant (FERC Accounts 310-346) must be directly assigned to the Generation function, except that some costs may need to be reclassified;

(C) Transmission Plant (FERC Accounts 350-359) must be directly assigned to the Transmission function, except that some costs may need to be reclassified. Transmission Plant is defined as both transmission lines and transmission substation equipment operating at voltages of at least 46 kilovolts, as well as transmission facilities and transmission substation equipment operating at voltages of at least 34.5 kilovolts if such facilities terminate within enclosed substations;

(D) Distribution Plant (FERC Accounts 360-373) must be directly assigned to the Distribution function, except that some costs may need to be reclassified;

(E) General Plant (FERC Accounts 389-399) must be directly assigned where possible. The remainder of the costs must be allocated to the appropriate functions using the O&M Labor allocator;

(F) Accumulated Depreciation must be functionalized in the same manner as the respective Plant accounts; and

(G) Each electric company must review its other rate base items and where possible directly assign the costs to the appropriate function. The remaining costs must be allocated to the appropriate functions using general allocators to be determined in each company's filing;

(b) Operation and Maintenance (O&M) Expense:

(A) Production O&M Expense (FERC Accounts 500-557) must be directly assigned to the Generation function, except that some costs may need to be reclassified;

(B) Transmission O&M Expense (FERC Accounts 560-574) must be directly assigned to the Transmission function, except that some costs may need to be reclassified;

(C) Distribution O&M Expense (FERC Accounts 580-598) must be directly assigned to the Distribution function, except that some costs may need to be reclassified;

(D) Customer Accounts O&M Expense (FERC Accounts 901-905) must be directly assigned where possible. The remainder of the costs must be allocated to the appropriate functions using general allocators to be determined in each company's filing, except for FERC Account 904, Uncollectible Accounts, which must be allocated using a Total Revenue Requirement allocator;

(E) Customer Service and Information O&M Expense (FERC Accounts 906-910) must be directly assigned where possible. The remainder of the costs must be allocated to the appropriate functions using general allocators to be determined in each company's filing;

(F) Sales O&M Expense (FERC Accounts 911-917) must be allocated exclusively to functions determined to be competitive by the Commission; and

(G) Administrative and General O&M Expense (FERC Accounts 920-935) must be allocated to the appropriate functions using the O&M Labor allocator; and

(c) Other Expenses:

(A) Amortization and Depreciation Expenses must be functionalized in the same manner as the respective Plant accounts; and

(B) All taxes must be identified as Federal, State, or Local Taxes;

(i) Taxes other than income taxes must be allocated in the following manner:

(I) Ad Valorem Taxes: Net Plant in Service;

(II) Payroll Taxes: Labor;

(III) Revenue Related Taxes: Total Revenue Requirement; and

(IV) Franchise Fees & Privilege Taxes: Distribution function; and

(ii) Income Tax Expenses must be calculated for each of the functions identified in section (2) of this rule; and

(d) Revenues: In a rate filing, required revenues must be calculated for each unbundling category using the traditional revenue requirement calculation methodology (recovery of costs plus a return on investment). For reporting purposes, revenues must be assigned to the appropriate category per the underlying tariff for which they were collected. Common revenues that cannot be directly assigned must be functionalized using the Net Plant allocation factor.

860-038-0220
Portfolio Options

(1) An electric company must provide each residential consumer who is connected to its distribution system with a portfolio of product and pricing options. An eligible customer may enroll in or exit renewable resource options at any time, subject to any switching fees approved by the Commission under subsection (8)(e) of this rule. The minimum term for customers enrolling in a market-based option is 12 months. Portfolio options will not be offered to large nonresidential consumers.

(2) Sections (3) through (8) of this rule apply to residential portfolio product and pricing options.

(3) By July 1 of each year, the Portfolio Options Committee will recommend portfolio options to the Commission that will be effective January 1 of the following year. Each recommended portfolio option shall specify a service period from 12 months to 36 months. The Commission is not bound by the recommendations of the Portfolio Options Committee.

(4) The portfolio must include at least one product and rate that reflects renewable energy resources and one market-based rate. The Portfolio Options Committee will recommend the resource content of each renewable energy resource product. At least one renewable energy resource product will contain "significant new" resources. The Portfolio Options Committee will recommend a definition of "significant" based on an evaluation of resource availability, resource cost, and other factors. The portfolio options may include options for the collection of funds for future renewable resource purchases or collection of funds for energy related environmental mitigation measures such as salmon recovery.

(5) Each electric company is responsible for administering the options, including but not limited to marketing and billing.

(6) Each electric company must acquire the renewable supply resources necessary to provide the renewable energy resources product through a Commission-approved bidding process or other Commission-approved means. Each electric company may acquire the resources necessary to provide the other product and pricing options at its discretion.

(7) Four months prior to the implementation of the portfolio product and pricing options an electric company must file tariffs for its portfolio options.

(8) This section applies to residential and small nonresidential product and pricing options. An electric company must develop portfolio rates as follows:

(a) The portfolio rates must be based on the unbundled costs identified through the application of OAR 860-038-0200;

(b) The portfolio rates for any class of customer must be based on the unbundled costs to serve that class;

(c) The portfolio rates must include any additional electric company costs that are incurred when a consumer chooses to be served under the portfolio rate option;

(d) The portfolio rates must exclude electric company costs that are avoided when a consumer chooses to be served under the portfolio rate option;

(e) An electric company may impose nonrecurring charges to recover the administrative costs of changing suppliers or rate options; and

(f) Rates must be established so that costs associated with the development or offering of rate options are assigned to the retail electricity consumers eligible to choose such rate options.

(9) This section applies to small nonresidential portfolio product and pricing options. The Portfolio Options Committee will recommend portfolio product and pricing options, if any, to the Commission for approval. The electric company must implement small nonresidential portfolio product and pricing options adopted by the Commission.

(10) By March 31 for the prior calendar year, an electric company must acquire or issue renewable energy certificates in an amount at least equal to the electric company's sales of renewable energy certificates to residential and small nonresidential consumers for each renewable resource option.

860-038-0240
Cost-of-Service Rate

(1) After March 1, 2002, an electric company must provide a cost-of-service rate option to cost-of-service consumers. Only one cost-of-service rate option may be offered by schedule to each class of consumers.

(2) Unless a new residential or small nonresidential consumer elects otherwise, the electric company will serve the consumer under the cost-of-service option.

(3) An electric company must develop cost-of-service rates as follows:

(a) The cost-of service rates must be based on the unbundled costs identified through the application of OAR 860-038-0200;

(b) The cost-of-service rates for any class of consumer must be based on the unbundled costs to serve that class;

(c) The cost-of-service rates must include any additional electric company costs that are incurred when a consumer chooses to be served under the cost-of-service rate option;

(d) The cost-of-service rates must exclude electric company costs that are avoided when a consumer chooses to be served under the cost-of-service rate option;

(e) An electric company may impose nonrecurring charges to recover the administrative costs of changing suppliers or rate options; and

(f) Rates must be established so that costs associated with the development or offering of rate options are assigned to the retail electricity consumers eligible to choose such rate options.

(4) An electric company must separately state in its tariffs transition charges or credits and the rates associated with the revenue requirement of retained resources and purchases assigned to residential and small nonresidential consumers.

(5) An electric company must separately identify in its tariffs other credits or charges such as the credit associated with power supply contracts with the Bonneville Power Administration.

(6) The electric company must design its cost-of-service rate for nonresidential consumers and one-time charges associated with returning to a cost-of-service rate so that residential consumers served under a cost-of-service rate are not assigned costs associated with other classes of consumers switching between direct access or standard offer and the cost-of-service rate. The electric company may limit switching through enrollment periods or by requiring minimum terms of service.

860-038-0250
Nonresidential Standard Offer

(1) By March 1, 2002, each electric company shall provide one or more standard offer rate options to large nonresidential retail electricity consumers and one or more standard offer rate options to small nonresidential consumers. Each electric company must designate one of the standard offers available to each customer class as the non-emergency default supply option.

(2) An electric company must develop the standard offer rate as follows:

(a) A standard offer rate option shall be a tariff approved by the Commission, which is priced based on supply purchases made on a competitive basis from the wholesale market plus the transition credit or transition charge, if any, and all other unbundled costs of providing standard offer service. A standard offer rate must reflect the full costs of providing standard offer service;

(b) The standard offer rates for any class of customer must be based on the unbundled costs to serve that class;

(c) The standard offer rates must include any additional electric company costs that are incurred when a consumer chooses to be served under the standard offer rate option;

(d) The standard offer rates must exclude electric company costs that are avoided when a consumer chooses to be served under the standard offer rate option;

(e) An electric company may impose nonrecurring charges to recover the administrative costs of changing suppliers or rate options; and

(f) Rates must be established so that costs associated with the development or offering of rate options are assigned to the retail electricity consumers eligible to choose such rate options.

(g) An electric company may offer a cost-of-service rate to large nonresidential consumers in lieu of a one-year standard offer rate option.

(3) Nonresidential cost-of-service consumers who do not choose direct access or a specific standard offer service will be served under the cost-of-service rate until they choose another service option. Large nonresidential consumers who are not cost-of-service consumers will be served under the non-emergency default supply option unless they elect direct access or a different standard offer service.

(4) An electric company must, for nonresidential consumers, identify any applicable transition charges or credits.

(5) An electric company must separately identify other credits or charges such as the credit associated with power supply contracts with the Bonneville Power Administration.

(6) The notice and deposit requirements listed in OAR 860-038-0280(4) and (5) apply to standard offer service.

860-038-0260
Direct Access

(1) By March 1, 2002, an electric company must allow nonresidential consumers to choose direct access.

(2) An electric company must develop direct access rates as follows:

(a) The direct access rates must be based on the unbundled costs identified through the application of OAR 860-038-0200;

(b) The direct access rates for any class of customer must be based on the unbundled costs to serve that class;

(c) The direct access rates must include any additional electric company costs that are incurred when a consumer chooses to be served under the direct access rate option;

(d) The direct access rates must exclude electric company costs that are avoided when a consumer chooses to be served under the direct access rate option;

(e) An electric company may impose nonrecurring charges to recover the administrative costs of changing suppliers or rate options; and

(f) Rates must be established so that costs associated with the development or offering of rate options are assigned to the retail electricity consumers eligible to choose such rate options.

(3) After March 1, 2002, subject to Commission approval, an electric company may enter into special contracts for distribution service but may not enter into special contracts for power supply.

(4) Operation of a special contract approved by the Commission prior to March 1, 2002, between an electric company and a retail electricity consumer that extends beyond March 1, 2002, will be governed by the terms of the contract.

(5) Line extension charges must be independent of the power supply option elected by a retail electricity consumer.

(6) Unless directed otherwise by the Commission, the electric company must standardize its direct access tariffs and contracts to the extent possible to conform to industry and national standards, and should include at least the following:

(a) Definitions of services;

(b) Rules for application for direct access service, including notice periods;

(c) Rules for switching among forms of service, including notice periods;

(d) Termination rights;

(e) Dispute resolution;

(f) Descriptions of required ancillary services, including statements of the conditions on self-supply, if any;

(g) Billing and payment;

(h) Liability and indemnification;

(i) All necessary service schedules and technical requirements; and

(j) Other provisions that the Commission determines are reasonable and necessary for direct access.

(7) An electric company must file direct access tariffs that are practical and workable in combination with tariffs required by the Federal Energy Regulatory Commission (FERC). The electric company must:

(a) Ensure the minimization of differences in service definitions between retail direct-access and wholesale open-access;

(b) Ensure that services that are permitted to be self-supplied by the FERC are permitted to be self-supplied by the electric company, unless the company obtains an exception from the Commission; and

(c) State rates, terms, and conditions in its Oregon tariffs that properly work in conjunction with the electric company's FERC tariffs and, if not identical to, can at least be easily compared with those required by the FERC.

860-038-0275

Direct Access Annual Announcement and Election Period

(1) On November 15 of each year (or the next business day if November 15 falls on a Saturday, Sunday, or legal holiday as defined by ORS 187.010), each electric company must announce the prices to be charged for electricity services in the next calendar year. The date on which the electric companies are required to announce such prices is "the Announcement Date."

(2) Electric companies must allow retail electricity customers that are eligible for direct access at least five business days after the Announcement Date to choose service under a cost-of-service rate option or to purchase electricity from either an electricity service supplier through direct access or an electric company through a standard rate offer.

(3) At least five business days before the Announcement Date, electric companies and electricity service suppliers must announce, and post on their websites, estimates of prices for electricity services in the subsequent calendar year or subsequent contract period if different than a calendar year:

(a) All electric companies and electricity service suppliers must continuously post the estimated prices announced under this rule on their websites until the Announcement Date.

(b) Electric companies' estimated prices will be the companies' estimates of the electricity service prices that will be in effect for the calendar year subsequent to the Announcement Date.

(c) Electricity service suppliers will determine estimated prices that will allow electricity consumers to compare the estimated prices of the electric company and electricity service supplier for the subsequent calendar year, or contract period if different than a calendar year.

(d) Announcing estimated prices as required by this rule creates no obligation on the part of the electric companies and/or electricity service suppliers to provide electricity service to any consumer at the estimated prices.

(e) If an electricity service supplier does not intend to sell electricity services in the subsequent calendar year or contract period, the electricity service supplier must announce, and post on a web site, that it does not intend to sell electricity services in the subsequent calendar year or contract period.

(4) Thirty days prior to the Announcement Date, electric companies and electricity service suppliers shall provide to the Commission a URL address for a website where the individual electric company or electricity service supplier will post prices and announcements as prescribed by this rule. The Commission will post the URL addresses on its website.

(5) At least once each year, electric companies must offer customers a multi-year direct access program with an associated fixed transition adjustment.

860-038-0280
Default Supply

(1) Default supply is an alternative available to nonresidential consumers served by direct access.

(2) The two types of default supply are emergency as defined in OAR 860-038-0005 and standard offer as defined in OAR 860-038-0250.

(3) Each electric company must provide the emergency option as follows:

(a) Emergency default service commences when an electric company is informed by the ESS or nonresidential consumer, or becomes aware, that an ESS is no longer providing service; and

(b) Each electric company must file tariffs with the Commission that include the emergency service option. An electric company must design emergency service rates to recover its costs of providing such service.

(4) A nonresidential consumer must give the electric company notice of intent to purchase or terminate purchase of standard offer service consistent with the applicable tariff provision.

(5) An electric company may require a deposit from a consumer applying to receive emergency default service or standard offer service. The electric company may disconnect a consumer receiving default service or standard offer service subject to OAR 860-021-0305 and 860-021-0505.

(6) Unless otherwise directed by a nonresidential consumer, an electric company must move an emergency service consumer from emergency default service to standard offer service within five business days of the nonresidential consumer's initial purchase of emergency default service. This provision does not limit a consumer's right to return from emergency default service or standard offer service to direct access.

860-038-0290
Preferential Curtailment

(1) Except as provided in sections (2) and (5), each electric company shall provide preferential curtailment of nonresidential direct access consumers.

(2) If an ESS is no longer providing service, the electric company must attempt to serve the returning consumer with market purchases or the electric company's excess generation.

(a) If served through market purchases or excess generation, the returning consumer will be charged rates for that service as defined in OAR 860-038-0280 (3)(b).

(3) If an ESS is no longer providing service, and neither market energy nor excess generation is available, the electric company may preferentially curtail returning nonresidential direct access consumers of that ESS.

(4) The electric company may collect a reasonable charge from a consumer to recover necessary costs for system upgrades that operationalize preferential curtailment of that consumer, using a Commission approved methodology.

(5) An electric company will not preferentially curtail non-residential direct access consumers if it is infeasible to do so or curtailment would negatively affect the electric system's reliability.

(a) Where an electric company will not enact preferential curtailment, the electric company will plan for and acquire capacity to account for a direct access consumer's potential return to the electric company's service.

(b) The electric company will design tariffs to collect charges from the direct access consumer that only recover the costs of the capacity investment and the generation that serves that consumer.

860-038-0300

Electric Company and Electricity Service Suppliers Labeling Requirements

(1) The purpose of this rule is to establish requirements for electric companies and electricity service suppliers to provide price, power source, and environmental impact information necessary for consumers to exercise informed choice.

(2) An electricity service provider must post a summary of the aggregated energy supply mix and associated emissions for the Direct Access load served in Oregon in the previous year. When historic data in unavailable, the ESS must use a reasonable estimate of future resource mix. The summary must be updated on November 15 of each year (or the next business day if November 15 falls on a Saturday, Sunday, or legal holiday as defined by ORS 187.010) and either included on or via a link on its indicative pricing website as required under OAR 860-038-0275.

(3) For each service or product it offers, an electric company must provide price, power source, and environmental impact information to all residential consumers annually, or at a frequency prescribed by the Commission. The information must be based on the available service options. The information must be supplied consistent with the requirements prescribed by the Commission. The electric company must report price information for each service or product for residential consumers based on the average monthly bill and price per kilowatt-hour for the available service options.

(4) An electric company and an electricity service supplier must provide price, power source and environmental impact information to nonresidential consumers consistent with the requirements and frequency prescribed by the Commission. An electric company and an electricity service supplier must report price information for nonresidential consumers as follows:

(a) The price and amount due for each service or product that a nonresidential consumer is purchasing;

(b) The rates and amount of state and local taxes or fees, if any, imposed on the nonresidential consumer;

(c) The amount of any public purpose charge; and

(d) The amount of any transition charge or credit.

(5) For power supplied through its own generating resources, the electric company must report power source and environmental impact information based on the company's own generating resources, not the unspecified market purchase mix. An electric company's own resources include company-owned resources and wholesale purchases from specific generating units, less wholesale sales from specific

generating units. An electric company's own resources do not include the non-energy attributes associated with purchases under the provisions of a net metering tariff or other power production tariff unless the electric company has separately contracted for the purchase of the Tradable Renewable Certificates. For net market purchases, the electric company must report power source and environmental impact information based on the unspecified market purchase mix. The electric company must report power source and environmental impact information for standard offer sales based on the unspecified market purchase mix.

(6) For purposes of power source and environmental impact reporting, an electric company and an electricity service supplier should use the most recent unspecified market purchase mix unless the electric company or electricity service supplier is able to demonstrate a different power source mix and environmental impact. A demonstration of a different mix must be based on projections of the mix to be supplied during the current calendar year. Power source must be reported as the percentages of the total product supply including the following:

(a) Coal;

(b) Hydroelectricity;

(c) Natural gas;

(d) Nuclear; and

(e) Other power sources including but not limited to new renewable resources, if over 1.5 percent of the total power source mix.

(7) Environmental impact must be reported for all retail electric consumers using the annual emission factors for the most recent available calendar year applied to the expected production level for each source of supply included in the electricity product. Environment impacts reported must include at least:

(a) Carbon dioxide, measured in lbs./kWh of CO_2 emissions;

(b) Sulfur dioxide, measured in lbs./kWh of SO_2 emissions;

(c) Nitrogen oxides, measured in lbs./kWh of NO_x emissions; and

(d) Mercury, measured in lbs/kWh of Hg emission.

(8) Every bill to a direct access consumer must contain the electricity service supplier's and the electric company's toll-free number for inquiries and instructions as to those services and safety issues for which the consumer should directly contact the electric company.

(9) The electricity service supplier must provide price, power source, and environmental impact in all contracts and marketing information.

(10) The electric company must provide price, power source, and environmental impact in all standard offer marketing information.

(11) By September 1, each electric company and each electricity service supplier making any claim other than unspecified market purchase mix must file a reconciliation report for the prior calendar year on forms prescribed by the Commission. The report must provide a comparison of the power source mix and emissions of all of the seller's certificates, purchase or generation with the claimed power source mix and emissions of all of the seller's products and sales.

(12) Each electricity service supplier and electric company owning or operating generation facilities shall keep and report such operating data about its generation of electricity as may be specified by order of the Commission.

860-038-0340
Electric Company Ancillary Services

(1) This rule applies to those ancillary services that are not within the exclusive jurisdiction of the Federal Energy Regulatory Commission.

(2) The Commission may require an electric company to provide ancillary services to facilitate direct access to consumers.

(3) The Commission may decide which ancillary services a direct access consumer may purchase directly from electricity service suppliers.

(4) An electric company must provide ancillary services to facilitate direct access that are comparable to the services it provides for its own retail electricity consumers.

860-038-0360
Electric Company Customer Metering Requirements

(1) The electric company must own/lease, install, test, read, remove, and maintain a customer meter for each retail electricity consumer receiving metered distribution services.

(2) The electric company's meter reading must be the basis for the electric company charges billed to the retail electricity consumer. The electric company must provide the results of the meter reading to the consumer's ESS in a timely manner, comparable to the provision of such information to its own non-distribution divisions, affiliates, and related parties for direct access customers served by those divisions, affiliates, and related parties. The electric company must not disclose meter data to any entity or person other than the retail electricity consumer, the consumer's ESS, or the Commission unless written authorization is obtained from the retail electricity consumer.

(3) The electric company must make available a standard meter and metering services to each retail electricity consumer that are adequate for the billing and other requirements of the electric company.

(4) The electric company must offer meters and metering services, other than the standard meters and metering services, that are necessary for an ESS to provide service to a retail electricity consumer. If an ESS requests that the electric company offer a specific meter capability or function or metering service, the electric company must consider and approve or deny the request within 10 business days. If the request is approved, the electric company must file rates with the Commission for such meter or

metering service within 30 days. If the request is denied, the ESS may appeal the decision to the Commission. The electric company must establish charges for different meter capabilities or functions and metering services subject to approval by the Commission.

860-038-0380
Aggregation

(1) For purposes of ensuring compliance with Commission standards for consumer protection, an aggregator must be registered by the Commission to combine retail electricity consumers in the service territory of an electric company into a buying group for the purchase of electricity and related services.

(2) The initial registration fee is $50.

(3) The annual renewal fee is $25.

(4) At a minimum, the aggregator must supply the following information:

(a) Name of aggregator;

(b) Name, address, and phone number of the aggregator's regulatory contact; and

(c) A signed statement from an authorized representative of the aggregator declaring that all information provided is true and correct.

(5) At a minimum, the aggregator must attest that it will:

(a) Furnish to consumers a toll-free number or local number that is staffed during normal business hours to enable a consumer to resolve complaints or billing disputes and a statement of the aggregator's terms and conditions that detail the consumer's rights and responsibilities;

(b) Comply with all applicable state and federal laws, rules, and Commission orders applicable to aggregators; and

(c) Adequately respond to Commission information requests applicable to aggregators and related to the provisions of this rule within 10 business days.

(6) An aggregator must take all reasonable steps, including corrective actions, to ensure that persons or agents hired by the aggregator, including but not limited to officers, directors, agents, employees, representatives, successors, and assigns adhere at all times to the terms of all state and federal laws, rules, and Commission orders applicable to aggregators.

(7) Annually, 30 days prior to expiration, a registered aggregator must notify the Commission that it will not be renewing its registration or it must renew its registration by submitting an application for renewal that includes an update of information specified in section (4) of this rule. The aggregator must state that it continues to attest that it will meet the requirements of section (5) of this rule. The authorized representative of the aggregator must state that all information provided is true and correct and sign the renewal application. The renewal is granted for a period of one year from the expiration date of the prior registration.

(8) No aggregator may make material misrepresentations in consumer solicitations, agreements, or in the administration of consumer contracts. Aggregators may not engage in dishonesty, fraud, or deceit that benefits the aggregator or disadvantages consumers.

(9) An aggregator must promptly report to the Commission any circumstances or events that materially alter information provided to the Commission in the registration process.

(10) The electric company must allow aggregation of electricity loads, pursuant to ORS 757, which may include aggregation of demand for other services available under direct access.

860-038-0400
Electricity Service Supplier Certification Requirements

(1) An electricity service supplier (ESS) must be certified by the Commission to sell electricity services to consumers.

(2) An ESS must be certified as either scheduling or nonscheduling as prescribed in OAR 860-038-0410.

(3) The initial certification fee is $400.

(4) The annual renewal fee is $200.

(5) An ESS applicant must file an application that contains the following information:

(a) Name of applicant, including owners, directors, partners, and officers, with a description of the work experience of key personnel in the sale, procurement, and billing of energy services or similar products;

(b) Name, address, and phone number of the ESS applicant's regulatory contact;

(c) Proof of authorization to do business in the state of Oregon;

(d) Dun and Bradstreet number, if available;

(e) Confirmation that the applicant (including owners, directors, partners, and officers) has not violated consumer protection laws or rules in the past three years;

(f) Audited financial statements of the ESS applicant (and its guarantor, if applicable) and credit reports consisting of:

(A) A balance sheet, income statement, and statement of cash flow for each of the three years preceding the filing and for the interim quarters between the end of the last audited year and the filing date; or

(B) For an applicant that has been in operation for less than three years, the audited balance sheets, income statements, and statements of cash flow for each of the years the company was in operation and for the interim quarters between the end of the last audited year and the filing date; or

(C) For an applicant that has been in operation for less than 12 months on the date the application is filed, such financial statements as are kept in the regular course of the applicant's business operations and pro-forma financial statements for a period of not less than 36 months.

(D) If audited financial statements are unavailable, the applicant may submit unaudited financial statements for each of the three years preceding the filing and for the interim quarters between the end of the last unaudited year and the filing date. The applicant must also submit a statement explaining why audited statements are not available.

(g) A showing of creditworthiness through documentation of tangible assets in excess of liabilities (i.e., tangible net worth) of at least $1,000,000 on its most recent balance sheet and demonstration of either its own investment grade credit rating pursuant to (A) or fulfillment of bond/guaranty requirements pursuant to (B):

(A) Investment grade rating means a suitable rating on the long term, senior unsecured debt, or if this rating is unavailable, the corporate rating, of a major credit rating agency.

(B) An applicant may use any of the financial instruments listed below, in an amount commensurate with the services and products it intends to offer, to satisfy the credit requirements established by this rule.

(i) Cash or cash equivalent (i.e., cashier's check);

(ii) A letter of credit issued by a bank or other financial institution, irrevocable for a period of at least 18 months;

(iii) A bond in a form acceptable to the Commission, irrevocable for a period of at least 18 months; or

(iv) A guaranty in a form acceptable to the Commission issued by a principal of the applicant or a corporation holding controlling interest in the applicant, which is irrevocable for at least 18 months. To the extent the applicant relies on a guaranty, the applicant must provide financial evidence sufficient to demonstrate that the lender or guarantor possesses the cash or cash equivalent needed to fund the guaranty.

(h) A showing of technical competence in energy procurement and delivery, information systems, billing & collection, and if subject to the requirements of section 16 of this rule, safety & engineering;

(i) A showing that its financial and technical competence is consistent with the services and products it intends to offer, and the targeted customer class(es) and geographical areas; and

(j) A statement as to whether the ESS is applying for certification as a scheduling or nonscheduling ESS and information documenting an ability to comply to the requirements of OAR 860-038-0410; and

(k) The authorized representative of the applicant must state that all information provided is true and correct and sign the application.

(6) At a minimum, an applicant must attest that it will:

(a) Furnish to consumers a toll-free number or local number that is staffed during normal business hours to enable a consumer to resolve complaints or billing disputes and a statement of the ESS's terms and conditions that detail the customer's rights and responsibilities;

(b) Comply with all applicable laws, rules, Commission orders, and electric company tariffs;

(c) Maintain insurance coverage, security bond, or other financial assurance commensurate with the types and numbers of consumers and loads being served, meet any other credit requirements contained in the electric company's tariffs, and cover creditors for a minimum of 90 days from the date of cancellation; and

(d) Adequately respond to Commission information requests within 10 business days.

(7) As conditions for certification, an ESS must agree to:

(a) Enter into an agreement or agreements with each respective electric company to assign to the electric companies any federal system benefits available from the Bonneville Power Administration to the residential and small-farm customers who receive distribution from an electric company and are served by the ESS; and

(b) Not enter into a Residential Sale and Purchase Agreement with the Bonneville Power Administration pursuant to Section 5(c) of the Pacific Northwest Power Act concerning federal system benefits available to residential and small farm customers receiving distribution from an electric company.

(8) Staff will notify interested persons of the application, allow 14 days from the date of notification for the filing of protests to the application (through submission of an email or letter to the staff), review the application, and make a recommendation to the Commission whether the application should be approved or denied.

(9) An applicant or a protesting party may request a hearing within 60 calendar days of the date of the staff recommendation. Upon determining the appropriateness of the request, the Commission will conduct a hearing as provided for in division 001 of the Commission's rules.

(10) The Commission may issue an Order granting the applicant's request for certification upon a finding that:

(a) The applicant paid the initial certification PUC fee, as required by OAR 860-038-0400(3);

(b) The applicant filed an application containing accurate, complete and satisfactory information that demonstrates it meets the requirements to be certified as an ESS.

(11) If the Commission grants the application, the Commission may include any conditions it deems reasonable and necessary. Further, upon granting the application, the Commission will certify the ESS for a period of one year from the date of the order.

(12) An ESS must take all reasonable steps, including corrective actions, to ensure that persons or agents hired by the ESS adhere at all times to the terms of all laws, rules, Commission orders, and electric company tariffs applicable to the ESS.

(13) An ESS must notify the Commission that it will not be renewing its certification or it must renew its certification each year as follows:

(a) An ESS must file its application for renewal 30 days prior to the expiration date of its current certificate;

(b) In its application for renewal the ESS must include the renewal fee, update the information specified in subsections (5)(a), (b), (i), and (j) of this rule, and state whether it violated or is currently being investigated for violation of any attestation made under the current certificate. The ESS must state that it continues to attest that it will meet the requirements of sections (6) and (7) of this rule. The authorized representative of the ESS must state that all information provided is true and correct and sign the renewal application;

(c) If the Commission takes no action on the renewal application, the renewal is granted for a period of one year from the expiration date of the prior certificate;

(d) If a written complaint is filed, or if on the Commission's own motion, the Commission has reason to believe the renewal should not be granted, the Commission will conduct a revocation proceeding per section (14) of this rule. The renewal applicant will be considered temporarily certified during the pending revocation proceeding.

(14) Upon review of a written complaint or on its own motion the Commission may, after reasonable notice and opportunity for hearing, revoke the certification of an ESS for reasons including, but not limited to, the following:

(a) Material misrepresentations in its application for certification or in any report of material changes in the facts upon which the certification was based;

(b) Material misrepresentations in customer solicitations, agreements, or in the administration of customer contracts;

(c) Dishonesty, fraud, or deceit that benefits the ESS or disadvantages customers;

(d) Demonstrated lack of financial, or operational capability; or

(e) Violation of agreements stated in sections (6) and (7) of this rule.

(15) An ESS must promptly report to the Commission any circumstances or events that materially alter information provided to the Commission in the certification or renewal process or otherwise materially impacts their ability to reasonably serve electricity consumers in Oregon.

(16) Each ESS that owns, operates, or controls electrical supply lines and facilities subject to ORS 757.035 must have and maintain its entire plant and system in such condition that it will furnish safe, adequate, and reasonably continuous service. Each such ESS must inspect its lines and facilities in such a manner and with such frequency as may be needed to ensure a reasonably complete knowledge about their condition and adequacy at all times. Such record must be kept of the conditions found as the ESS considers necessary to properly maintain its system, unless in special cases the Commission specifies a more complete record. The ESS must have written plans describing its inspection, operation, and maintenance programs necessary to ensure the safety and reliability of the facilities. The written plans

and records required herein must be made available to the Commission upon request. The ESS must report serious injuries to persons or property in accordance with OAR 860-024-0050.

860-038-0405
ESS Emissions Planning Report

(1) From the effective date of these rules through May 30, 2027, each ESS certified pursuant to ORS 757.649 that has sold electricity to retail electricity consumers in Oregon in the previous calendar year or has executed a contract to sell electricity to retail electricity consumers in Oregon within the following three calendar years are required to file a copy of the annual greenhouse gas emissions report submitted to the Oregon Department of Environmental Quality in accordance with HB 2021, Section 5(4)(a) within 10 days of filing with the Oregon Department of Environmental Quality.

(2) Beginning on January 1, 2027, each ESS certified pursuant to ORS 757.649 that has sold electricity to retail electricity consumers in Oregon in the previous calendar year or has executed a contract to sell electricity to retail electricity consumers in Oregon within the following three calendar years are required to file a report in accordance with subsection (3) of this rule. If prescribed by the Commission, each ESS must use established forms to provide information required under this rule.

(3) Each ESS must file an Emissions Planning Report on or before June 1st of each calendar year that includes the following:

(a) A cover-page with a checklist for each item required by the report, as set forth in this subsection, and an indication of where that information is found in the report and whether specified information is confidential subject to a protective order. A uniform template for the cover page checklist and Protective Order will be provided on the Commission website under the Reports & Forms section.

(b) Summary of the specific electricity-generating resources, MWh generation from those resources, emissions per MWh (MTCO2e/MWh) associated with serving Oregon Direct Access customers, and all emissions from the previous calendar year that were reported to DEQ.

(c) Load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers.
(d) An estimate of the annual greenhouse gas emissions associated with serving Oregon Direct Access customers, forecasted for the following three consecutive years.

(e) Action plan that specifies annual goals and resources, including specified and unspecified market purchases, that the ESS plans to use to meet the load and emissions forecast consistent with the DEQ emissions reporting methodology.

(f) An analysis of the $/MWh (levelized if under different pricing structure) that the customer will be charged for service related to compliance for each of the next 3 years.

(g) Anticipated actions to facilitate rapid reductions of greenhouse gas emissions at reasonable costs to retail electricity consumers served by the ESS, including but not limited to:

(i) Development of non-emitting dispatchable resources;

(ii) Demand response offerings;

(iii) Energy efficiency offerings; and

(iv) Onsite renewable generation.

(4) ESS's serving customers or generating electricity in multiple electric company service territories must separate the report's contents referred to in section (3) by each unique service territory.

(5) Commission staff and interested persons may file written comments on each ESS's Emissions Planning Report within 45 calendar days of the filing. The ESS may file a written response to any comments within 30 calendar days thereafter. After considering written comments, the Commission may decide to commence an investigation, begin a proceeding, or take other action as necessary to make a determination regarding HB 2021, section (5)'s requirement for continual and reasonable progress toward compliance with the clean energy targets set forth in section 3 of HB 2021.

(6) Upon conclusion of the Commission review of the report in section (3) of this rule, the Commission will issue a decision to acknowledge the ESS's Emissions Planning Report if it demonstrates continual and reasonable progress toward compliance with clean energy targets. If the Commission determines the Emissions Planning Report does not demonstrate continual and reasonable compliance, the ESS must file an updated Emissions Planning Report that addresses the Commission's concerns within 90 days.

(7) The ESS must post a non-confidential version of the subsection 5(3) report on its website within 30 days of the Commission decision whether to accept the report. The ESS must also provide information about its compliance report to its customers by bill insert or other Commission-approved method.

(8) Availability of Information:

(a) The following information shall be available for review only by Qualified Statutory Parties that have executed a modified protective order:

(i) Information regarding an analysis of the $/MWh (levelized if under different pricing structure) that the customer will be charged for service related to compliance for each of the next 3 years, as required by Section 3(f).

(b) For purposes of this Section, Qualified Statutory Parties means Commission Staff and the Citizen's Utility Board.

(c) The following information shall be available for review only by Non-Market Participants that have executed a modified protective order:

(i) Action plan that specifies annual goals and resources, including specified and unspecified market purchases, that the ESS plans to use to meet the load and emissions forecast consistent with the DEQ emissions reporting methodology, as required in Section 3(e);

(ii) Information regarding the load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers, as required by Section 3(c); and

(iii) The summary of the specific electricity-generating resources and MWh generation from those resources, as required by Section 3(b).

(d) For purposes of this section, Non-Market Participants includes Commission Staff, the Citizen's Utility Board, and non-profit organizations engaged in environmental advocacy that do not otherwise participate in electricity markets.

860-038-0410
Scheduling

(1) Each ESS shall be certified as either scheduling or nonscheduling.

(2) Each scheduling ESS shall schedule the resources to serve the direct access loads for which it has scheduling responsibility with the appropriate control area operators. Scheduling shall be in accordance with all generally accepted regional and Western Electricity Coordinating Council rules and guidelines.

(a) Only a single scheduling ESS may schedule all the resources and other services for any single direct access consumer. Multiple ESSs may provide services to any individual direct access consumer, but only through a single scheduling ESS;

(b) Each scheduling ESS shall be responsible for ensuring that all necessary point-to-point transmission services have been acquired across the facilities of third parties, above and beyond the network integration transmission service provided on the facilities of the electric company to serve the direct access loads for which it has scheduling responsibility;

(c) Each scheduling ESS shall be responsible for forecasting the requirements for serving the direct access loads for which it has scheduling responsibility and arranging for resources;

(d) Each scheduling ESS shall be responsible for settling imbalances with electric companies for the total resources and direct access loads for which it has scheduling responsibility.

(3) A nonscheduling ESS must contract with a scheduling ESS or control area operator for all scheduling services.

860-038-0420
Electricity Service Supplier Consumer Protection

(1) All advertising and marketing activities by electricity service suppliers must be truthful, not misleading, and in compliance with Oregon's Unfair Trade Practices Act (ORS 646.605 through 646.656).

(2) No person or entity may offer to sell electricity services available pursuant to direct access unless it has been certified by the Commission as an ESS.

(3) Sections (3) through (6) of this rule do not apply when a consumer is changing suppliers. Sections (3) through (6) apply when an ESS is discontinuing service to a consumer. An ESS must give its customers at least 10 business days written notice, as prescribed in section (5) of this rule, before the ESS may discontinue service.

(4) The written notice of intent to discontinue service to the ESS customer must be printed in boldface type and must state in easy to understand language:

(a) The name and contact information of the ESS and the service location intended to be discontinued;

(b) The reasons for the proposed discontinuance;

(c) The earliest date for discontinuance; and

(d) The amount necessary to be paid to avoid discontinuance of services, if applicable.

(5) The ESS must serve the notice of discontinuance in person or send it by first class mail to the last known address of the ESS customer. Service is complete on the date of personal delivery or, if service is by U. S. mail, on the day after the U. S. Postal Service postmark or the day after the date of postage metering.

(6) Not less than 10 business days prior to discontinuance of service to an ESS customer, the ESS must notify the serving electric company, by mutually acceptable means, that the ESS will no longer be supplying energy to that ESS customer. If an ESS and a consumer waive the 10-day notice, pursuant to section (8) of this rule, the ESS must still notify the electric company of its intent to discontinue a consumer's service as soon as it notifies the consumer that service is to be discontinued. The written notice must contain the following:

(a) Name and contact information of the ESS that is discontinuing service, the consumer's name, account number, service location and, if applicable, the electric company's unique location identifier;

(b) Earliest date for discontinuance; and

(c) Necessary information applicable to the transfer of the consumer's service.

(7) This section of this rule applies to any alleged violation of the rules in Division 038 applicable to electricity service suppliers.

(a) When a dispute occurs between an ESS customer and an ESS about any charge or service, the ESS must acknowledge the dispute with a response to the customer within 5 calendar days. The ESS must thoroughly investigate the matter and report the results of its investigation to the ESS customer within 15 calendar days. If the ESS is unable to resolve the matter within 15 calendar days, the ESS must advise the customer of the option to request internal supervisory review of unregulated disputes and to request the Commission's assistance in resolving a dispute within the Commission's jurisdiction;

(b) An ESS customer may request the Commission's assistance in resolving a dispute within the Commission's jurisdiction by contacting the Commission's Consumer Services Division. The Commission must notify the electricity service supplier upon receipt of such a request;

(c) The Commission's Consumer Services Division will assist the complainant and the electricity service supplier in an effort to reach an informal resolution of the dispute. The ESS must provide the Commission with the necessary information to assist in resolving the dispute. The ESS must answer the registered ESS dispute within 15 calendar days of service of the complaint;

(d) If a registered ESS dispute cannot be resolved informally, the Commission's Consumer Services Division will advise the complainant of the right to file a formal written complaint.

(A) The formal written complaint must state the facts of the dispute and the relief requested and must be filed with the Filing Center in compliance with the rules regarding confidential information and filing set out in OAR 860-001-0070, 860-001-0140 through 860-001-0150,and 860-001-0170.

(B) The formal complaint must be filed with the Filing Center at PUC.FilingCenter@state.or.us. If complainant does not have access to electronic mail, the complaint may be mailed, faxed, or delivered to the Filing Center at the address set out in OAR 860-001-0140, and the formal complaint must include a request for waiver of the electronic filing and service requirements.

(C) The Commission will serve the complaint on the ESS. The Commission may electronically serve the ESS with the complaint if the electronic mail address is verified prior to service of the complaint and the delivery receipt is maintained in the official file.

(D) The ESS must answer the complaint within 15 calendar days of service of the complaint by the Commission.

(E) The Commission will set the matter for expedited hearing. A hearing may be held on less than 10 calendar days' notice when good cause is shown. Notice of the hearing will be provided to the complainant and the ESS at least 12 hours before the date and time of the hearing.

(F) Filing dates for formal complaint proceedings are calculated and enforced per OAR 860-001-0150.

(8) Within the terms of a written contract, a customer and an ESS may agree to arrangements other than those specified in sections (3), (4), (5), and (6) of this rule, if the following requirements are met:

(a) The contract must include an exact copy of the paragraphs in subsection (8)(b) of this rule. The paragraphs must be in bold type of at least 12-font size. Immediately following the paragraphs, there must be a line for the consumer's signature and the date.

(b) The agreement must contain the following notice: IF YOU SIGN THIS AGREEMENT, YOU MAY GIVE UP CERTAIN RIGHTS YOU HAVE UNDER OAR 860-038-0420(3) through (6). These rules state: The ESS must insert the complete text of OAR 860-038-0420(3) through (6). THIS MAY AFFECT YOUR ABILITY TO ARRANGE FOR OTHER ENERGY SERVICE.

860-038-0445

Coordination of Supplier Changes and Billing

(1) This rule applies to electricity service suppliers and to electric companies providing service options to nonresidential consumers. For purposes of this rule, "supplier" means an electricity service supplier or electric company.

(2) An ESS may not provide service to a consumer without a written contract or electronic authorization between the customer and the ESS and the submission by the ESS of a Direct Access Service Request (DASR) to the electric company to switch such customer from its then-current supplier to the ESS. The DASR must contain all information required by the electric company's direct access tariff to effect the switching of such customer's supplier.

(3) An ESS or electric company shall not submit a DASR unless it possesses written or electronic authorization from the consumer.

(4) The ESS must maintain records sufficient to demonstrate compliance with this rule including a copy of the contract authorizing the change in supplier for a period of one year from the date the customer authorized a change in electric service to such supplier. Upon request, the supplier must make such records available to the electric company or the Commission.

(5) An acceptable DASR must conform to industry electronic data interchange protocols.

(6) The written contract or electronic authorization must contain, at a minimum, the following information:

(a) The consumer's name, current account number, and an electric company's unique location identifier, if available;

(b) The service address and the consumer's mailing address;

(c) The type of service being purchased;

(d) The name of the new supplier that will be supplying the service;

(e) The effective date and time of change of supplier;

(f) The consumer's billing preference (electric company only, electricity service supplier only, or both);

(g) Identification and explanation of any nonrecurring charges associated with the change of supplier;

(h) A statement to the effect that the consumer is authorized to make the change and authorizes the change to the new supplier; and

(i) The consumer's signature or electronic authorization and title.

(7) Any change of supplier without an acceptable DASR conforming to the requirements of section (5) of this rule and a written contract or electronic authorization conforming to the requirements of section (6) of this rule shall constitute a violation of this rule.

(8) An ESS must obtain acceptance of its DASR at least 10 business days prior to the effective date of the change.

(9) An electric company must accept or reject a DASR and provide notification to the ESS, within three business days of submission. Upon acceptance of a DASR, the electric company must notify the current supplier of the change within three business days.

(10) If the change date of suppliers does not coincide with the serving electric company's established meter reading schedule, the new supplier will pay the applicable tariffed charges to the electric company necessary to accommodate an off-cycle meter reading.

(11) Each supplier must supply, upon request from a consumer, a copy of the service description and rates applicable to the type or types of service furnished to the consumer.

(12) A consumer will receive a consolidated bill from the electric company unless the consumer chooses one of the following:

(a) A separate bill from every individual supplier that provides products or services to the consumer; or

(b) A consolidated bill from an ESS.

(13) An electric company and the ESS must cooperate to ensure the exchange of information in a timely manner necessary for billing purposes. The electric company or the ESS may request the Commission's assistance in resolving a dispute within the Commission's jurisdiction by contacting the Commission's Consumer Services Division. The Commission will notify the appropriate company upon receipt of such a request. The appropriate company must answer the registered dispute within 15 calendar days of service of the complaint.

(14) If the consumer receives a consolidated billing from an electric company, the ESS must provide the information to the electric company required in OAR 860-038-0300, and the electric company must provide that information on the bill.

(15) If the consumer chooses a consolidated billing by the ESS, the electric company must provide the information to the ESS required in OAR 860-038-0300 and the ESS must provide that information on the bill.

(16) An electric company and ESS must cooperate to resolve any consumer complaint.

(17) An electric company and the ESS must exchange all necessary information to facilitate the billing of consumers and the exchange of funds using industry electronic data interchange protocols. If there is a dispute regarding the information exchange, the ESS or the electric company may appeal to the Commission for assistance in resolving the dispute.

(18) The party contracting with the electric company for the delivery of services shall be obligated to pay the electric company's transmission and distribution charges in accordance with the electric company's applicable tariffs. When the ESS is the contracting party, the direct access customer's failure to pay the ESS the full amount of ESS charges shall not relieve the ESS of its obligation to the electric company for

delivery services in accordance with the electric company's direct access tariff. The electric company shall have access to the security posted by the ESS in accordance with the terms of the electric company's direct access tariff in the event the ESS defaults in the payment of electric company charges to the ESS.

(19) Absent a contract with the electric company described in section (18) of this rule, when payment, including amounts for regulated charges, is made directly to an electricity service supplier or electric company, the payment must be allocated as follows:

(a) As directed by the nonresidential consumer; or

(b) Absent specific direction from the nonresidential consumer, in the following sequence:

(A) Past due regulated;

(B) Current regulated;

(C) Past due unregulated charges in proportion to the outstanding balance; and

(D) Current unregulated charges in proportion to the outstanding balance; and

(c) If a contractual agreement between an ESS customer and an electricity service supplier dictates payment allocations other than those identified in section (b) of this rule, the electricity service supplier will provide notification with the bill that failure to pay the regulated charges can result in disconnection of service.

(20) Services subject to the jurisdiction of the Commission may not be discontinued, disconnected, or placed in jeopardy because of nonpayment of unregulated charges.

860-038-0450
Location of Underground Facilities

An ESS and its customers shall comply with requirements of chapter 952 regarding the prevention of damage to underground facilities.

860-038-0460
Construction, Safety, and Reporting Standards for Electricity Service Suppliers

An ESS shall comply with the construction, safety, and reporting standards set forth in OAR chapter 860, division 024.

860-038-0470
Attachments to Poles and Conduits Owned by Public, Telecommunications, and Consumer-Owned Utilities

Pole and conduit attachments shall comply with the rules set forth in OAR chapter 860, division 028.

860-038-0480
Public Purposes

(1) Each electric company that offers direct access to its retail electricity consumers and each electricity service supplier that provides electricity services to direct access consumers in the electric company's service territory will collect a public purpose charge from its retail electricity consumers until January 1, 2026.

(2) Except as provided in section (6) of this rule, electric companies and electricity service suppliers will bill and collect from each of their retail electricity consumers a public purpose charge equal to 3 percent of the total revenues billed to those consumers for electricity services, distribution, ancillary services, metering and billing, transition charges, and other types of costs that were included in electric rates on July 23, 1999.

(3) The electricity service suppliers will remit monthly to each electric company the public purpose charges they collect from the customers of each electric company.

(4) The electricity service suppliers will remit monthly the public purpose charges collected from direct service industrial consumers they serve to the electric company in whose service territory the direct service industrial site is located.

(5) The electric company whose territory abuts the greatest percentage of the site of an aluminum plant that averages more than 100 average megawatts of electricity use per year will collect monthly from the aluminum company a public purpose charge. The aluminum company will remit to the appropriate electric company a public purpose charge equal to 1 percent of the total revenue from the sale of electricity services to the aluminum plant from any source. Annually, the aluminum company will submit to the electric company an affidavit from a certified public accountant verifying that the costs for electricity services at the site of the aluminum plant and the remittance of the public purpose charges are accurate for the previous calendar year.

(6) A retail electricity consumer, including an aluminum plant as described in section (5) of this rule, may receive credits against its public purpose charges for qualifying expenditures incurred for new energy conservation and the above-market costs of new renewable energy resources at any site if the following qualifications for becoming a self-directing consumer are met:

(a) The consumer has used more than one average megawatt of electricity at any such site in the prior calendar year; and

(b) The consumer has received final certification from the Oregon Department of Energy for expenditures for new energy conservation and/or new renewable energy resources.

(7) Self-directing consumers may not claim a public purpose credit for energy conservation measures that were started prior to July 23, 1999. For energy conservation measures that were started on or after July 23, 1999, but prior to the implementation of direct access, a self-directing consumer may claim a public purpose credit if either of the following conditions is met:

(a) The energy conservation measure did not receive funding from an electric company conservation program and was certified by the Oregon Department of Energy after July 23, 1999; or

(b) The energy conservation measure did receive funding from an electric company conservation program and was certified by the Oregon Department of Energy after July 23, 1999, but the self-directing consumer repaid the amount of such funding (cost of audit and incentives plus interest) no later than 90 days following the implementation of direct access; provided that, a self-directing consumer shall not be required to repay the amount of any energy conservation audit related to a conservation measure if the audit was completed prior to January 1, 2000. The cost of an audit that identifies multiple energy conservation measures shall be prorated among such measures.

(c) For purposes of this subsection, "started" means that a contract has been executed to install or implement an energy conservation measure.

(8) The Oregon Department of Energy will establish specific rules and procedures that are consistent with these rules for qualifying a self-directing consumer's expenditures.

(9) The electric company will apply the self-direction credit, determined by the Oregon Department of Energy, toward the consumer's public purpose obligation.

(10) Each electric company will establish five separate accounts for the public purpose charges to be funded from its collections of public purpose charges as follows:

(a) Energy conservation in schools;

(b) New cost-effective local energy conservation and new market transformation;

(c) Above-market costs of new renewable energy resources;

(d) New low-income weatherization; and

(e) Construction and rehabilitation of low-income housing.

(11) Each electric company will allocate the public purpose funds it collects (billed less uncollectible amounts) from electricity service suppliers and consumers to the five public purpose accounts as follows:

(a) Energy conservation in schools — 10.0 percent;

(b) Local and market transformation conservation — 56.7 percent;

(c) Above market costs of new renewable energy resources — 17.1 percent;

(d) Low-income weatherization — 11.7 percent; and

(e) Low-income housing — 4.5 percent.

(12) Each electric company will adjust the local and market transformation conservation and above market costs of new renewable energy resources accounts specified in subsections 11(b) and (c) of this rule for the credits returned to self-directing customers for conservation or renewable resource expenditures certified by the Oregon Department of Energy.

(13) Each electric company will distribute funds from the public purpose accounts at least monthly as follows:

(a) The funds for conservation in schools to the school districts located in its service territory;

(b) The funds for local and market transformation conservation as directed by the Commission;

(c) The funds for renewable energy resources as directed by the Commission;

(d) The funds for low-income weatherization to the Housing and Community Services Department; and

(e) The funds for low-income housing to the Housing and Community Services Department Revolving Account.

(14) Should the Oregon Department of Energy request reimbursement for costs of administering public purpose funds in accordance with its responsibilities under ORS 757.612(3)(e), the electric companies must, within 30 days, provide reimbursement as provided in ORS 757.612(3)(c). The Oregon Department of Energy's reimbursement request must be limited to activities related to implementing public purpose programs and be consistent with its legislatively approved budget limitation allotted to administer the schools program. On March 1 of each year, the Oregon Department of Energy must provide to the Commission an accounting of the reimbursements received the preceding calendar year for administrative activities performed under ORS 757.612(3)(e).

(15) Each electric company will coordinate with the Oregon Department of Energy to determine, by January 1 of each year, the allocation of public purpose funds for schools to the school districts according to the following methodology:

(a) From the Department of Education, collect current total weighted average daily membership (ADMw) as defined in ORS 327.013 and average daily membership (ADM) for each school district that contains schools served by the electric company;

(b) For each of the school districts, compute the ratio of ADM in schools served by the electric company to total ADM;

(c) For each school district, multiply its total ADMw by the ratio of ADM in schools served by the electric company to total ADM. The result is an estimate of ADMw in schools served by the electric company;

(d) Add the estimates of ADMw for each school district; and

(e) Compute the percentage of the total ADMw represented by each school district. These are the percentages that will be used to allocate the public purpose funds for schools to school districts for the 12-month period beginning on January 1 of each year.

(16) The electric company may be reimbursed for the reasonable administrative costs it incurs to collect and distribute the public purpose funds. Those administrative costs will be deducted from the total amount of public purpose funds collected by the electric company before the funds are allocated to the five public purpose accounts. The electric company will also pay from the total public purpose funds collected or from a specific fund any other administrative costs the Commission directs to be paid for

implementation of the public purpose requirements. The entities responsible for administering the public purpose funds will pay for their costs of implementing the public purpose requirements from the public purpose funds they receive from the electric company.

(17) The electric companies and the administrators of the public purpose funds will collect sufficient information so that biennial reports can be made to the Legislature on what has been accomplished with the public purpose funds and how those funds have benefited the consumers of each electric company. Specifically, information must be collected so that the reporting requirements of ORS 757.617 can be fulfilled.

(a) Each electric company must report the total funds collected by source (that is, electric company customers, electricity service suppliers and self-directing consumers) for public purposes, the amounts distributed to the administrators of each public purpose fund, and its administrative costs;

(b) Each administrator of public purpose funds must report, at a minimum:

(A) The amount of funds received;

(B) The amount of funds spent;

(C) Its administrative costs; and

(D) Its results, for example, measures installed, projects funded, energy saved, homes weatherized, and low-income homes built/rehabilitated.

860-038-0500
Code of Conduct Purpose

The Code of Conduct rules (OAR 860-038-0500 through 860-038-0640) govern the interactions and transactions among the electric company, its Oregon affiliates, and its competitive operations. The Code of Conduct is designed to protect against market abuses and anti-competitive practices by electric companies in the Oregon retail electricity markets.

860-038-0520
Electric Company Name and Logo

An electric company may allow its Oregon affiliates and its competitive operations the use of its corporate name, trademark, brand, or logo in advertisements of specific electricity services to existing or potential consumers located within the electric company's service area, as long as the Oregon affiliate or its competitive provider includes a disclaimer in its communications. The disclaimer must be written in a bold and conspicuous manner or be clearly audible, as appropriate for the communication medium. The disclaimer must be included in all print, auditory and electronic advertisements.

(1) The disclaimer for an Oregon affiliate must state the following: {Name of Oregon affiliate} is not the same company as {name of electric company} and is not regulated by the Public Utility Commission of Oregon. You do not have to buy {name of Oregon affiliate}'s products or services to continue to receive your current electricity service from {name of electric company}.

(2) The disclaimer for a competitive operation must state the following: 'You do not have to buy {product/service name} to continue to receive your current electricity service from {name of electric company}.'

860-038-0560
Treatment of Competitors

(1) An electric company shall treat the competitors of its Oregon affiliates and its competitive operations fairly in all respects and in a manner consistent with the treatment it affords any of its Oregon affiliates or competitive operations in the electric company's:

(a) Provision of supply;

(b) Provision of capacity;

(c) Provision of electricity services;

(d) Provision of information obtained as a result of providing either electric service to its non-direct access customers within its allocated service territory, or transmission and distribution services to direct access customers;

(e) Offering of discounts;

(f) Tariff discretion; and

(g) Processing requests for electricity related services. This section shall not apply to the provision or joint purchasing of corporate services such as accounting, auditing, financial, legal, or information technology services.

(2) An electric company shall not condition or otherwise tie the provision of any regulated services provided by the electric company, nor the availability of discounts of rates or other charges or fees, rebates, or waivers of terms and conditions of any regulated services provided by the electric company, to the taking of any electricity services or directly related products from its Oregon affiliates or competitive operations.

(3) An electric company shall not assign a consumer to whom it currently provides electricity services to any of its Oregon affiliates or competitive operations, whether by default, direct assignment, option, or by any other means, unless that means is equally available to all competitors.

860-038-0580
Prevention of Cross-subsidization Between Competitive Operations and Regulated Operations

(1) Other than information that is routinely made public by an electric company, or for which a tariff has been approved subject to OAR 860-086-0020, an electric company must not provide electric company operational or marketing information to its competitive operations unless it makes such information available to ESSs and other entities that provide electricity services or directly related products on identical terms and conditions.

(2) The electric company must identify and separately account for revenues and costs of its competitive operations.

860-038-0590
Transmission and Distribution Access

(1) An electric company may be relieved of some or all of the requirements of this rule by placing its transmission facilities under the control of a regional transmission organization consistent with FERC Order No. 2000 and obtaining Commission approval of an exemption.

(2) An ESS may request transmission service, distribution service or ancillary services under standard Commission tariffs and FERC-approved tariffs. The electric company shall coordinate the filings of these tariffs to ensure that all retail and direct access consumers are offered comparable services at comparable prices.

(3) Except as otherwise directed by OAR 860-038-0290, each electric company shall provide nondiscriminatory access to transmission, distribution and ancillary services, including transmission into import-limited areas and local generation resources within import-limited areas, to serve all retail consumers. An electric company shall not give preference or priority in transmission and distribution pricing, transmission and distribution access, or access to, pricing of, or provision of ancillary services and local generation resources, to itself or its affiliate relative to persons or entities requesting transmission or distribution access to serve direct access consumers. No preference or priority may be given to, nor any different obligation assigned to, any consumer based solely on whether the consumer is purchasing service from an electric company or an ESS.

(a) Any transmission or distribution capacity to which an electric company has entitlements, by ownership or by contract, for the purpose of serving its Oregon load shall be made available to an electric company and ESSs that are serving such load on at least a pro rata basis. An electric company shall describe in its tariff filings how it proposes to provide substantively comparable transmission and distribution service to all retail consumers at the same or similar rates if:

(A) Access to the electric company's transmission or distribution facilities or entitlements is restricted by contract or by regulatory obligations in other jurisdictions; or

(B) If providing transmission or distribution service on a pro rata basis would result in stranding generating capacity owned or provided through contract by the electric company;

(b) Except for those ancillary services required by FERC to be purchased from an electric company, an ESS may acquire, on behalf of the retail loads for which it is responsible, all ancillary services required relative to the transmission of electricity by any combination of:

(A) Purchases under the electric company's Open Access Transmission Tariff;

(B) Self-provision; or

(C) Purchases from a third party;

(c) Energy imbalance obligations, including the pricing of imbalances and penalties for imbalances, shall be developed to reasonably minimize imbalances and to meet the needs of the direct access market environment. The electric company shall address such energy imbalance obligations in its proposed FERC tariffs. Energy imbalance obligations imposed upon ESSs, including the entity serving the standard offer load, and consumers purchasing service from the electric company, shall comply with the following:

(A) The obligations shall impose substantively comparable burdens upon ESSs, including the entity serving the standard offer load, and consumers purchasing service from the electric company, and shall not unreasonably differentiate between consumers that are entitled to direct access on the basis of customer class, provider of the service, or type of access;

(B) The obligations shall recognize the practical scheduling and operational limitations associated with serving retail consumer loads in the direct access environment, but shall require ESSs, including the entity serving the standard offer load, to make reasonable efforts to minimize their energy imbalances on an hourly basis;

(C) The obligations shall be designed with the objective of deterring ESSs, including the entity serving the standard offer load, and consumers purchasing service from the electric company from burdening electric system operation or gaining economic advantage by under-scheduling, over-scheduling, under-generating or over-generating. The obligations shall not be punitive in nature; and

(D) The obligations shall enable an electric company and ESSs, including the entity serving the standard offer load, to settle for energy imbalance obligations on a financial basis, unless otherwise mutually agreed to by the parties.

(d) Where local generation is required to operate for electric system security or where there is insufficient transmission import capability to serve retail loads without the use of local generation, the electric company shall make services available from such local generation under its ownership or control to ESSs consistent with the electric company's provision of services to standard offer consumers, residential consumers, and other retail consumers. The electric company shall also specify such obligations in appropriate sales contracts prior to any divestiture of such resources;

(e) The electric company's tariffs shall specify prices, terms, and conditions for scheduling, billing, and settlement. Other functions may be specified as needed;

(f) An electric company's tariffs shall include a dispute resolution process to resolve issues between the electric company and the ESSs that serve the retail load of an electric company in a timely manner. Such processes shall provide that unresolved disputes related to such retail access matters may be appealed to the Commission.

(4) If adherence to OAR 860-038-0590 requires FERC approval of tariff or contract provisions, the electric company must petition FERC for the approval of the tariff or contract provisions within 90 days of the effective date of this rule. Subsequent tariffs or contracts requiring FERC approval will be made in a timely manner.

860-038-0600

Joint Marketing and Referral Arrangements

(1) For joint marketing, advertising, and promotional activities an electric company shall not:

(a) Provide or acquire leads on behalf of its Oregon affiliates;

(b) Solicit business or acquire information on behalf of its Oregon affiliates;

(c) Give the appearance of speaking or acting on behalf of its Oregon affiliates except that an electric company, pursuant to a customer request, may provide information about electricity services or directly related products offered by the electric company's Oregon affiliates. Prior to providing the information, the electric company must inform the customer that:

(A) Other providers may exist; and

(B) The customer does not have to purchase these electricity services or directly related products from the electric company's Oregon affiliate in order for the customer to continue to receive the customer's current electricity service from the electric company;

(d) Represent to consumers or potential consumers that it can offer electricity services or directly related products from the electric company's Oregon affiliates bundled or packaged with its tariffed services; or

(e) Request authorization from its consumers to pass on proprietary consumer information exclusively to its Oregon affiliates.

(2) An electric company shall not engage in joint marketing, advertising, or promotion of its electricity services or directly related products with those of its Oregon affiliates in a manner that favors the electricity services or directly related products of the Oregon affiliate. Such joint marketing, advertising, or promotion includes, but is not limited to, the following:

(a) Acting or appearing to act on behalf of its Oregon affiliates in any communications and contacts with any existing or potential consumers, subject to the exception in (1)(c) above;

(b) Joint sales calls;

(c) Joint proposals, either as requests for proposals or responses to requests for proposals;

(d) Joint promotional communications or correspondence, except that an electric company may allow its Oregon affiliates access to consumer bill advertising inserts according to the terms of a Commission approved tariff, so long as access to such inserts is made available on the same terms and conditions to unaffiliated entities offering similar services as the Oregon affiliates that use bill inserts; or

(e) Joint presentations at trade shows, conferences, or other marketing events within the state of Oregon.

(3) An electric company may participate in meetings with its Oregon affiliates to discuss technical or operational subjects regarding the electric company's provision of transmission or distribution services

to the consumer; but only in the same manner and to the same extent the electric company participates in such meetings with unaffiliated entities and their consumers.

860-038-0620
Access to Books and Records

(1) An electric company must provide the Commission with full access to all of the electric company's and affiliates' books and records in order to review all transactions between an electric company and its Oregon affiliates.

(2) An electric company and its affiliates shall maintain separate books and records, and, whenever possible, prepare unconsolidated financial statements.

(3) An electric company and its competitive operations shall maintain sufficient records to allow for an audit of the transactions between an electric company and its competitive operations. At its discretion, the Commission may require an electric company to initiate, at the electric company's expense, an audit of the transactions between an electric company and its competitive operations performed by an independent third party.

860-038-0640
Compliance Filings

By June 1 of each odd numbered year, an electric company must file a verified report prepared by an independent third-party regarding the electric company's compliance with OAR 860-038-0500 through 860-038-0620 for the prior two calendar years.

860-038-0700
Definitions for New Large Load Direct Access Program

(1) Unless otherwise defined in section (2), the definitions set forth in OAR 860-038-0005 are applicable to New Large Load Direct Access Programs.

(2) As used in the New Large Load Direct Access Program rules:

(a) "Average Historic Cost-of-Service Load" means the average monthly Cost-of-Service Eligible Load during the 60 month period beginning five years prior to the date a consumer gives binding notice of participation in the New Large Load Direct Access Program.

(b) "Cost-of-Service Eligible Load" means the load of a consumer that is eligible for a cost-of-service rate.

(c) "Incremental Demand Side Management" means the effective net impact of energy efficiency measures and demand response implemented at a facility after a consumer gives binding notice of participation in the New Large Load Direct Access Program.

(d) "New Large Load Direct Access Program" means a direct access program offering by an electric utility that meets the requirements set forth in OAR 860-038-0700 through 860-038-0760.

(e) “New Large Load Direct Access Service Transition Rate” means a rate that is applied to load served under the New Large Load Direct Access Program.

860-038-0710
Requirement to Enable a New Large Load Direct Access Program

(1) An electric company that enables direct access service must enable a New Large Load Direct Access Program for New Large Load consumers, subject to the requirements set forth in rules governing New Large Load Direct Access Programs. The New Large Load must be separately metered or be measured based on a determination that has comparable accuracy and is mutually agreeable between the electric company and the consumer.

(2) For purposes of these rules, “New Large Load” means any load associated with a new facility, an existing facility, or an expansion of an existing facility, which:

(a) Has never been contracted for or committed to in writing by a cost-of-service consumer with an electric company; and

(b) Is expected to result in a 10 average megawatt or more increase in the consumer’s power requirements during the first three years after new operations begin.

860-038-0720
Nonresidential Standard Offer, Default Supply, and Return to Cost of Service

(1) New Large Load Direct Access Program participants are subject to the requirements set forth in OAR 860-038-0250 and OAR 860-038-0280, except as set forth in section (3) of this rule.

(2) A New Large Load Direct Access Program participant may return to cost-of-service rates under the same rates and terms of service as the electric company’s current cost-of-service opt-out offers for direct access service consumers, except as set forth in section (3).

(3) To mitigate the rate impact to existing cost-of service customers, an electric company must request Commission approval of a forward-looking rate adder applicable to New Large Load Direct Access Program participants returning to cost-of-service rates or rates under OAR 860-038-0250 and 860-038-0280 when the electric company forecasts that:

(a) The return to rates under OAR 860-038-0250 and 860-038-0280 for an individual or group of New Large Load Direct Access Program participants will result in a significant increase to existing cost-of-service rate; or

(b) The return to a cost-of-service rate for an individual or group of New Large Load Direct Access Program participants will result in a significant increase to existing cost of service rate.

(4) The Commission will consider the rate adder under Section (3) of this rule as part of a tariff filing.

(5) The electric company must file annual tariff updates that justify any rate adder developed according to this rule or any updates to the approved rate adder.

860-038-0730

New Large Load Eligibility Requirements

(1) A New Large Load Direct Access Program is only available for consumers contracting for energy resources that do not include any allocation of coal-fired resources as defined in ORS 757.518 (1)(b)(B) after January 1, 2030. For the purposes of this rule, "coal-fired resource" does not include a facility generating electricity that is included as part of a limited duration wholesale power purchase made by an Energy Service Supplier for immediate delivery to retail electricity consumers that are located in this state for which the source of the power is not known.

(2) Prior to taking service under the program, New Large Load Direct Access participants must sign and provide to the electric company an affidavit representing that the participant's energy supply will not include any allocation of coal-fired resources consistent with the requirements of section (1).

(a) Prior to providing service, the electric company must provide a copy of the affidavit provided by a New Large Load Direct Access participant to the Commission.

(b) New Large Load Direct Access participants that are found in violation of the provisions of section (2) of this rule will be enrolled in the general cost-of-service opt out program in the next direct access enrollment window.

(3) For at least one period of 12 consecutive months within the first 36 months of receiving service, the actual load of a facility served under the New Large Load Direct Access Program must meet or exceed 10 average megawatts, unless the shortfall in load below that threshold is attributable to equipment failure, energy efficiency, load curtailment or load control, or other causes outside the control of the New Large Load Direct Access Program participant.

860-038-0740

New Large Load Program Enrollment and Rates

(1) Each New Large Load consumer must notify the electric company of its intent to enroll in the New Large Load Direct Access Program and opt out of cost-of-service rates at the earlier of either:

(a) A binding written agreement with the utility for eligible new load, or

(b) One year prior to the expected starting date of the incremental load.

(2) Section (1) is waived for the eligible New Large Load consumer that has entered into a written agreement with an electric company prior to September 30, 2018, indicating its intent to receive distribution service from an electric company and for which the electric company has not planned to provide generation supply service.

(3) An electric company must charge New Large Load Direct Access participants a New Large Load Direct Access Service Transition Rate that recovers the following:

(a) 20 percent of the fixed generation costs for five years; and

(b) All reasonable costs of administering the New Large Load Direct Access Program.

(4) Participants receiving service under the New Large Load Direct Access program must also pay an Existing Load Shortage Transition Adjustment on the sum of the Existing Load Shortage for the participant and the Existing Load Shortage of all of the participant's affiliated consumers.

(a) For purposes of this rule, "affiliated consumer" means a consumer, a controlling interest which is held by another consumer, engaged in the same line of business as the holder of the controlling interest.

(b) For the purposes of this rule, "Existing Load Shortage" means the larger of zero or a consumer's Average Historic Cost-of-Service Load plus Incremental Demand Side Management less the average Cost-of-Service Eligible Load during the previous 60 months.

(c) The Existing Load Shortage Transition Adjustment is a charge or credit equal to:

(A) 75 percent of fixed generation costs plus net variable power cost transition adjustments during the first five years after enrollment in the New Large Load Direct Access Program; and

(B) 100 percent of fixed generation costs plus net variable power cost transition adjustments after the first five years of enrollment in the New Large Load Direct Access program.

(5) A participant may be exempted from charges made under section (4) if the participant can demonstrate that the change in load in question is not due to load shifting activity. For purposes of this rule, "load shifting" means the relocation of facilities, equipment, processes, manufacturing, employees or any economic activity for the deliberate purpose of increasing load at locations participating in the New Large Load Direct Access Program from locations not subject to the New Large Load Direct Access Program. The electric company tariff must include provisions detailing procedures and requirements for a participant to make this demonstration.

(6) A participant must also pay non-bypassable charges, in accordance with OAR 860-038-0170.

860-038-0750

De-Enrollment Due to Failure to Meet Load Standard

If the actual load of a facility served under the New Large Load Direct Access Program fails to meet the requirements outlined in OAR 860-038-0730(3) and the electric company elects to de-enroll the participant, the electric company must provide written notification to the New Large Load participant and the Commission of its proposal to move the participant to the appropriate cost-of-service rate schedule.

(1) Within 60 days of notification, the participant may provide a written response to the electric company and the Commission to demonstrate that its reduction in load to less than 10 average megawatts was the result of equipment failure, energy efficiency, load curtailment or load control, or other causes outside the control of the New Large Load Direct Access Program participant.

(2) The electric company may not transition a participant to a new rate structure under this provision before 90 days has passed since the notice from the electric company.

860-038-0760

Reporting

Each electric company must file a status report to the Commission within two months of total enrollment in New Large Load Direct Access Programs reaching 25 average megawatts, 50 average megawatts, 100 average megawatts, and 80 percent of any enrollment limit adopted by the Commission.