ORDER NO. 00-596

ENTERED SEPT 28, 2000

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 380

In the Matter of a Rulemaking Proceeding to Implement SB 1149 Relating to Electric Restructuring.	)))	ORDER

DISPOSITION: RULES ADOPTED/AMENDED

On February 14, 2000, the Public Utility Commission of Oregon opened a rulemaking proceeding to develop rules to implement provisions of SB 1149, an electric industry restructuring bill passed by the 1999 Oregon Legislative Assembly and signed by the Governor on July 23, 1999. Notice of the rulemaking and a statement of the fiscal impact were filed with the Oregon Secretary of State in February 2000. Notice of the rulemaking was published in the Oregon Bulletin on March 1, 2000.

SB 1149, §15 (OR Laws 1999, Chapter 865) requires the Commission to adopt administrative rules necessary to implement sections 1 to 20 of the bill, including rules on specific issues. On September 27, 1999, Commission Staff (Staff) met with interested persons to develop a plan to carry out the tasks necessary to implement SB 1149. On February 2, 2000, participants agreed to a schedule that included workshops, rounds of written comments, public comment hearings in several locations, a draft order, and a final order.

Public comment hearings were held in Portland, Salem, Bend, and Medford, Oregon, during April 2000. Four rounds of written comments were filed, with the last completed on June 20, 2000.

On August 2, 2000, Kathryn Logan and Allen Scott, Administrative Law Judges assigned to this case, issued a Draft Order. Parties were given until August 11, 2000, to file comments. Based on the comments, a revised Draft Order was issued on August 22, 2000.

On August 29, 2000, the Commission deliberated on this matter at a special public meeting in Salem, Oregon. The Commission considered the Draft Order, the comments of the participants, and the remainder of the record in this case and entered the decisions set out in this order.

Structure of this Order

The Notice of Rulemaking sets out 16 rules proposed by Staff. The rules were the subject of settlement discussions among Staff, Portland General Electric (PGE), PacifiCorp, and a Coalition of participants.[1] The participants in these settlement discussions arrived at an agreement on five rules (called Coalition Rules in this order). The Coalition Rules form the nucleus of the restructuring scheme embodied in the rules we adopt in this order. Because of their importance, they will be discussed in the first section of this order.

Several of the other 11 rules are still the subject of significant controversy. These rules will be discussed in numerical order following our discussion of the Coalition Rules.

Coalition Rules

We congratulate the participants on their willingness to do the hard work which resulted in the Coalition Rules. We conclude that the Coalition Rules, except for proposed ORS 860-038-0120 - Administrative Valuation, should be adopted. Those rules, and the other rules we adopt in this order, conform to the letter and spirit of SB 1149 (codified as OAR 757.600 to 757.691). We believe they provide an efficient process for completing the steps necessary to move to direct access and that they appropriately protect all customer classes. We discuss the Coalition Rules briefly below and note our conclusions. We are aware that not all participants in the case joined in the agreement on the Coalition Rules and that even some of the participants in the negotiations are not unreserved in their approval of each rule. We note the reservations where significant and comment on them.[2]

Goals. The Coalition adopted several Goals as a guide to the development of these proposed rules. They include the following:

1. Honor Oregon's traditional public-process approach to resource decision making.
2. Design a fair administrative valuation process to value generating resources on a one-time basis.
3. Streamline the review of sales under an auction process without sacrificing the public interest.
4. Promote the creation of a competitive generating market.
5. Establish fair and reasonable transition costs and credits.

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[1] The Coalition includes the following: The Citizens' Utility Board (CUB), Associated Oregon Industries (AOI), Oregon Restaurant Association (ORA), Industrial Consumers of Northwest Utilities (ICNU), Northwest Energy Coalition (NWEC), Fair and Clean Energy Coalition (FCEC), Oregon Office of Energy (OOE), Building Owners and Managers' – Portland Metropolitan (BOMA), and PG&E National Energy Group.

[2] In its comments on the original Draft Order, BOMA withdrew its support for the Coalition Rules. It cites, as reasons for its change of heart, the uncertainty relating to the administrative valuation issue, the impact of current market conditions, and lingering reservations about the benefits of deregulation. It asks the Commission to suspend the proposed rules and establish a new docket "to develop protections for consumers to be incorporated into the Proposed Rules."

6. Comply with SB 1149 rate option mandates.
7. Provide large nonresidential consumers with regulated rate options to supplement and backstop their competitive market options.

The Commission endorses these Goals and applies them to our consideration of the Coalition Rules and the other rules we adopt in this order. We note that Goal 2, relating to an administrative valuation process, cannot be completely achieved at this time because legal issues require additional consideration and perhaps legislative action (See discussion of OAR 860-038-0120 below). However, the Goal itself is unassailable and we will apply it to our further consideration of the administrative valuation process.

OAR 860-038-0080 - Resource Policies and Plans

This rule sets out one of the basic policies underlying the proposed rules: that an electric company may retain in revenue requirement only those resources that will be needed to serve its Oregon residential and small nonresidential consumers. Moreover, the rule sets out the policy that the Commission will make a one-time valuation of the Oregon large nonresidential consumers' share of an electric company's generating resources.

To aid in the accomplishment of these policies, Subsection (3)(a) requires each electric company to produce a resource plan which provides information relating to its resources, including its share of residential, small nonresidential and large nonresidential loads, a forecast of revenue requirement, other factors influencing value, future market prices, future loads and estimated fair market value. Subsection (3)(b) requires the resource plan to state whether a generating resource should be retained in the electric company's revenue requirement to serve residential and small nonresidential consumers and thus administratively valued; sold through the auction process; or removed from the electric company's Oregon revenue requirement and administratively valued.

Subsection (3)(c) requires that the resource plan identify and analyze the impacts of implementing the plan, including the effect on load/resource balance and the effect on rates. Subsection (3)(d) requires the resource plan to set out a recommended implementation timeline. Subsection (3)(e) requires that the resource plan be developed in a public process allowing for participation by all affected groups.

Section (4) calls for the Commission to consider the resource plan in a contested case proceeding and to issue an order approving, modifying, or rejecting the resource plan. The electric company's options with respect to a modified or rejected plan are set out.

Section (5) permits an electric company or any nonresidential consumer to propose a change in the definition of "large nonresidential consumer" as set out in OAR 860-038-0005(23) and (50). If such a request is made, the Commission will conduct a proceeding to consider adoption of the modification. The change will be adopted if it is in the public interest based on certain specific factors set out in the rule, including the goal of including in the definition "as many nonresidential consumers" as feasible.[3]

Section (6) requires that when a resource plan has been approved or when an electric company has accepted modifications requested by the Commission, the plan must be implemented. Until implementation, transition charges and credits must be determined by an ongoing valuation method under OAR 860-038-0140. Section (8) provides that a Resource Plan may be amended.

Section (7) provides a temporary process for developing rates for Oregon consumers of an electric company that qualifies as a "multi-state electric company," under OAR 860-038-0001. This process will not be used after December 31, 2002.

OAR 860-038-0100 - Auction Process

Sections (1) through (4) of this rule provide that when the Commission has issued a final order valuing an electric company's generating resources and the company decides to sell some generating resources, it must do so under the auction process approved by the Commission in Order No. 99-765 (UE 102). However, in contrast to that order, the rule allows affiliates of the electric company to participate in the auction under requirements set out by the Commission to ensure fairness to all participants.

Sections (5) and (6) set out the Commission's standard for approval of the results of an auction of all or a portion of a generating resource. If a guaranteed approval price for a resource was set under OAR 860-038-0120(4) and the sales price is not less than that figure, the Commission must approve the sale as being in the public interest unless there are terms or conditions that have a "material adverse effect on the bid price and that differ from the terms and conditions assumed in establishing the guaranteed approval price." If the sales price is less than the guaranteed approval price, the Commission may nevertheless approve the sale if it finds that it is in the public interest. Under Section (6), if no guaranteed approval price has been established for the resource, the Commission may approve the sale only if it finds that the sale is in the public interest under ORS 757.480 and OAR 860-027-0025. Finally, Section (7) provides that the electric company may recover the costs of the auction process through the transition balancing account (*See* OAR 860-038-0160).

OAR 860-038-0120 - Administrative Valuation Process

This proposed rule establishes the process by which the Commission will determine the value of the Oregon Share of all the generating resources (with certain exceptions) of an electric company. This determination would be made in a contested case proceeding based upon the testimony of independent appraisers hired by the company, by the Commission, or by

[3] In comments on the original Draft Order, The City of Portland (Portland) suggests that the October 15, 2000, deadline for filing of proposed changes in this definition is too close to the date for the filing of tariffs, October 1, 2000. It asks that the deadline be changed to October 20, 2000, or 15 working days after the filing of tariffs.

one or more other parties and on other relevant information regarding the value of the resources. The costs of the independent appraisers hired by the Commission or the company would be recoverable through the transition balancing account under most circumstances. The results of the valuation process may lead to an amendment of the Resource Plan.

Section (6) provides for arbitration of disagreements between the company and the Commission or between one or more other parties and the Commission as to the value of the generating resource. The arbitrator would be chosen by the independent appraisers involved in the contested case portion of the valuation process. The arbitrator's decision would be made in accordance with a so-called "baseball arbitration" process in which the arbitrator must choose one of the values presented by the appraisers during the contested case valuation proceeding. Subsection (6)(b)(A)(ii) provides that the Commission will immediately confirm the arbitrator's decision unless it discovers procedural irregularities in the arbitration.

Subsection (6)(b)(A)(iii) provides that following the arbitrator's decision, the Commission may decide to retain one or more generating resources or portions of resources in the electric company's Oregon revenue requirement for the use of Oregon small nonresidential and residential consumers. If the Commission decides to retain a resource, the arbitrator's decision will establish the value for purposes of determining the transition charges and credits applicable to the company's Oregon large nonresidential consumers. Subsection (6)(b)(A)(iv) provides that for those generating resources that the Commission decides not to retain in the company's Oregon revenue requirement, the company may either accept the arbitrator's value and remove the resource from its revenue requirement or place the resource into the auction process under OAR 860-038-0100. If the resource is sent to auction, no guaranteed approval price will apply and the Commission will approve the sale without further consideration under ORS 757.480 and OAR 860-027-0025.

The Commission supports this rule. It provides a process for valuing resources that is complex but thorough and fair. We believe it meets the dictates of SB 1149 that the interests of retail electricity consumers and utility investors be reasonably balanced (*See* ORS 757.607 (2)). However, we will not adopt it at this time. We believe the arbitration provision in Section (6) may involve an unlawful delegation of authority by a government agency. In particular, Subsection (6)(b)(A)(ii), which would require the Commission to "immediately confirm the arbitrator's decision" unless it finds procedural irregularities, is problematic from that standpoint. We also note that this proposed rule might impact the appeal rights of parties involved in the proceeding. Section (3), relating to the employment of independent appraisers, also concerns us. It allows the costs of such appraisers to be recovered by the utility through the transition balancing account. That method of recovery may be beyond the scope of the Commission's authority to require utilities to pay for Commission expenses.

We have requested that our legal counsel consider these questions and report its conclusions to us in the near future. If we are assured that the rule is legally sound, we will adopt it as soon as practicable, along with rules outlining the procedures to be followed. If legal problems are present, we will delay any final action on this rule until the Oregon Legislature has had the opportunity to make statutory changes which will allow us to adopt the rule in its present form. We will join with the Coalition in supporting those changes. This necessary delay in adopting an administrative valuation rule should not have an impact on progress toward implementation of SB 1149. The rules we adopt in this order will allow utilities to begin the process of developing their resource plans and taking other steps required by the rules.

OAR 860-038-0140 - Ongoing Valuation

This rule provides that an electric company will use an ongoing valuation method to determine the transition costs or transition credits applicable to Oregon residential and small nonresidential consumers. The electric company may not, however, use an ongoing valuation method to determine those charges or credits applicable to large nonresidential consumers, except where a Resource Plan for the company has not been implemented or in the case of a multi-state electric company. Section (2) of the rule provides that an electric company must propose one or more ongoing valuation methods in its rate filings and that any method proposed must address certain factors.

OAR 860-038-0160 - Transition Costs and Credits

This rule provides that all Oregon retail electric consumers 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 company as determined pursuant to the various valuation methods set out in other portions of the rules. Section (7) provides that the Commission may set a period of recovery of such costs or credits of up to 10 years. Section (2) of the rule provides that if the electric company retains the nonresidential share of a resource in its revenue requirement and also retains the Oregon residential share of the resource, residential and small non-residential consumers of that company will bear the entire revenue requirement of such generating resources. Section (3) sets out the various methods of determining the transition costs and credits, depending on the method of valuation and the presence of incentives. Section (4) provides that transition costs or benefits will be allocated 100 percent to Oregon retail electricity consumers for the Oregon share of investments that are not resources, other regulatory assets, demand side management assets existing as of October 1, 2001, and retired or abandoned plant for which the Commission established costs recovered before January 23, 1999.

Other Rules

OAR 860-038-0001 - Scope and Applicability of Rules

This rule is not disputed. It makes the proposed rules applicable to electric companies and electrical service suppliers (ESSs) (See definitions in OAR 860-038-0005). However, the rules do not apply to electric companies that serve fewer than 25,000 consumers in Oregon unless they offer direct access or offer to sell electricity services available under direct access.

OAR 860-038-0005 - Definitions

Staff's proposed rule sets out 63 definitions. Most either occasioned no comment or were modified during the proceeding and are no longer in dispute. The definition of "ancillary services" was disputed. The term "New," as used in the term "new energy conservation" was also a matter of controversy. Agreement has been reached on that matter, as described below.

(4) "Ancillary Services." Staff's definition states that ancillary services are "those services necessary or incidental to the transmission and delivery of electricity from generating facilities to retail electric consumers, . . ." The rule then provides a non-exclusive list of such services: scheduling, frequency regulation, load shaping, load following, spinning reserves, supplemental reserves, reactive power voltage control and energy balancing services.

PacifiCorp argues that the definition of ancillary services should be more consistent with the Federal Energy Regulatory Commission's (FERC) current definition. Moreover, according to PacifiCorp, the definition should not include unduly limiting language and "should be reasonably acceptable to a wide range of parties." PacifiCorp recommends the following definition:

> (4) "Ancillary Services" means those services necessary to support the transmission and distribution of electricity from resources to retail consumers while maintaining reliable operation of the electric company's system. Such services shall be those ancillary services included in the FERC-accepted open access transmission tariffs of the electric company, and also such other ancillary services specified by the Commission as necessary to implement retail choice in Oregon.

PacifiCorp's proposed use of the term "resources" rather than "generation facilities" is designed to make clear that the rule includes energy purchased and delivered from other systems or at a major market point in addition to power from generators in the control area. Itemization of the specific services in the rule, as Staff proposes, would, according to PacifiCorp, increase the likelihood of conflict with FERC's or North American Electric Reliability Council's (NERC) evolving future definitions. If the Commission insists on some specificity, PacifiCorp suggests that the rule could more easily accommodate future revisions if it enumerated *functions* rather than specific services. PacifiCorp sets out a list of 14 functions which might be itemized if the Commission feels it necessary to provide a list: regulation, frequency response, load following, contingency reserve-spinning, contingency reserve-supplemental, reactive power supply from generation, voltage control from generation, system black start capability, real power losses, energy imbalance, dynamic transfer, scheduling, system control, and dispatch.

(31) "New." Staff's definition of "new" as it is used in the phrase, "new energy conservation" was disputed. However, it appears that Staff, ICNU, OOE, PGE, and PacifiCorp have arrived at an agreement which clarifies, through amendments to OAR 860-038-0005(31) and OAR 860-038-0480(7), which investments in conservation made by self-directing consumers between the passage of SB 1149 and the implementation of direct access are eligible for public purpose credits.

Commission Disposition

As to the term "Ancillary Services," the Commission concludes that PacifiCorp's suggestion that the term "resources" be used rather than "generation facilities" is a good idea that makes clear the inclusion of energy purchased and delivered from other systems or at a major market point. Otherwise, we conclude that Staff's definition is appropriate. It closely follows the definition in SB 1149. Moreover, we believe the non-exclusive listing proposed by Staff will be helpful to those affected by the rules. We see no benefit in including an even larger list, such as that offered by PacifiCorp.

As to the term "new," we have examined the amendment to OAR 860-038-0005(31) and adopt it.

We will make one change in this rule based on our Staff's recommendation. Section (2) sets out the composition of the Advisory Committee which will provide recommendations to the Commission regarding portfolio options under OAR 860-038-0220. We will add to the Advisory Committee's membership a representative of small nonresidential consumers, since that group will also be affected by decisions made on portfolio options.

OAR 860-038-0200 - Unbundling

This rule requires electric companies to separately identify their embedded costs on a function-by-function basis. The unbundled costs include those costs associated with functions that a retail electricity consumer could self-supply or could purchase from another entity. The unbundling must be done in a manner that facilitates rate development.

PacifiCorp suggests that the test period and methodology for setting rates should be set within each company's filing rather than in these rules.

Commission Disposition

Due to the need to meet legislative timelines, and due to the complexity of the filings, it makes sense for the test period to be established by rule. We adopt the rule as drafted.

OAR 860-038-0220 - Portfolio Options

This rule requires an electric company to provide a portfolio of product and pricing options to residential consumers who are connected to the company's distribution system. The Advisory Committee, as defined in OAR 860-038-0005(2), will make portfolio option recommendations to the Commission. The residential portfolio must have at least one product and rate that reflects renewable energy resources and at least one market based rate. The Advisory Committee may recommend small nonresidential portfolio product and pricing options to the Commission.

CUB, FCEC/NWEC, OOE, Renewable Northwest Project (RNP), PacifiCorp and PGE made comments. We adopt the changes suggested by FCEC/NWEC which clarify that portfolio options *will not* be offered to large nonresidential consumers, and change the word "rate" to "portfolio product and pricing options."

OOE believes that the language in Section (4) limits the number of portfolio options. We read the language differently and find that the language establishes minimum options but does not limit the number of options which can be recommended to us by the Advisory Committee. We leave the language as drafted.

PacifiCorp objects to an annual bidding process for portfolio options. Staff addressed that concern by adding the language "or other Commission-approved means" to the proposed rule. This provides PacifiCorp with alternatives to acquire portfolio resources if the competitive bidding process is not successful. PacifiCorp also objects to an open enrollment process. RNP believes that open enrollment is essential. Staff recommends that the Advisory Committee determine whether an open enrollment process is workable and make a recommendation to the Commission. We adopt Staff's amendments.

PGE does not believe that the Commission should require the portfolio option to be offered to small nonresidential consumers. Staff believes that the Advisory Committee should make a recommendation to the Commission about this subject. Since PGE has a seat on the Advisory Committee, it can make its interests known at the time of the recommendation. We agree with Staff's recommendation.

Commission Disposition

Consistent with our discussion above, we adopt the rule as amended.

OAR 860-038-0240 - Cost-of-Service Rate

Under this rule, electric companies must provide a cost-of-service rate option to residential and small nonresidential consumers by October 1, 2001. This option may be offered by schedule to each class of consumers. Large nonresidential consumers cannot be offered this option. This rule is not disputed. We adopt the rule as proposed.

OAR 860-038-0250 - Nonresidential Standard Offer

Large nonresidential retail electricity consumers and small nonresidential consumers served under direct access shall be provided one or more standard offer rate options by October 1, 2001. The rule directs how the standard offer must be developed.

This rule should alleviate Oregon Power Users Alliance's (OPUA) concerns regarding how its members are supplied, and provides a suitable option to direct access. Staff and the Coalition/PGE members are in agreement with the rule. We adopt the rule as proposed.

OAR 860-038-0260 - Direct Access

This rule sets forth the development and components of direct access rates for nonresidential consumers. This rule is not disputed, although PGE suggests that we eliminate the language in Section (7) referring to industry and national standards. We choose to leave the rule as written as it allows this Commission to make changes, if necessary, to the format and content of the tariffs and contracts. We adopt the rule as proposed.

OAR 860-038-0280 - Default Supply

Default supply is an alternative available to nonresidential consumers who are served by direct access. The two types of default supply are emergency and standard offer. This rule is not disputed. We adopt the rule as proposed.

OAR 860-038-0300 - Electric Company and Electricity Service Suppliers Labeling Requirements

This rule requires electric companies and ESSs to provide price, power source, and environmental impact information to consumers. This information will allow consumers to make informed decisions about their choice of electricity supplier. The rule requires that the information be supplied in a format prescribed by the Commission and sets out procedures and details as to the content of the disclosure. There are differences between the requirements applicable to electric companies and ESSs, as there are between the requirements pertaining to residential and nonresidential consumers.

Section (2) requires disclosure of the information to residential consumers on at least a quarterly basis. It also requires that the electric company provide, if available, a Uniform Resource Locator (URL) address where the information may be obtained.

Section (3) provides for disclosure of the information to nonresidential consumers on bills *or* with bills. It also requires the provision of a URL address if available.

Section (4) requires that when the electric company provides power through its own generating resources, it base the power source and environmental impact information on its own generating resources, not on the "net system power mix" (*See* OAR 860-038-0005(30)). For market purchases, the electric company must report source and impact information based on the net system power mix. Under Section (5), an ESS must use the net system power mix for its power source and environmental impact reporting, unless it can demonstrate a different source and impact.

PacifiCorp challenges the differing requirements for electric companies and ESSs with respect to the disclosure of power source and environmental impact information. It claims that these differences may create "the perverse situation in which an ESS could purchase energy from a utility and sell that same energy to a customer within the utility's service area claiming the system mix, whereas the utility would be required to claim its own generation mix for the exact same energy." This situation could, according to PacifiCorp, confuse consumers who might receive differing information under two different labels. PacifiCorp recommends that the Commission require the same reporting basis, either the net system or the specific claim.

OOE disagrees with the provision in the proposed rule that allows the companies to report their own generating resources mix rather than the net system mix. It argues that use of the net system mix would better reflect the actual impacts of consumers' supply choice. It points out, for example, that reduced sales will not force a utility to reduce output of its resources because the freed-up resources may be sold into the wholesale market. OOE also recommends a lengthy addition to the rule setting out detailed format and disclosure requirements and requiring reconciliation reports and maintenance of certain data by each ESS and electric company. Staff did not adopt the detailed reporting requirements in its proposed rules but did include the reconciliation and data maintenance requirements.

PGE argues that disclosure to residential consumers should be made on an annual basis rather than quarterly, as the proposed rule requires. PGE also argues that the provider should be allowed to provide power source and environmental impact information through a URL address *in lieu of* a bill, rather than as an additional means, as the proposed rule allows.

Commission Disposition

The Commission adopts the rule proposed by Staff. It underwent many changes during the proceeding in response to comments from various parties. We conclude that it provides a sound framework for the important requirement of disclosure to all consumers of price, power source, and environmental impact. The consistency in format dictated by the rule will be of aid to consumers. The time frames set out for disclosure are reasonable. The rule provides a clear description of the specific information required. The alternative of notice through the URL address in addition to the regular means of notification will be beneficial to consumers. We believe that the use of electric companies' own generating resources as set out in the rule will give a more accurate picture than would the use of the net system power mix. We do not think that the differences in the requirements imposed on electric companies and on ESSs will present significant problems. We will, of course, stand ready to alter the rules if abuses or unintended results occur.

OAR 860-038-0340 - Electric Company Ancillary Services

Ancillary services are defined in OAR 860-038-0005(4), as discussed above. The definition we adopt in this order includes a non-exclusive list of ancillary services. Additional services may thus be included, if any are identified. Issues relating to the definition of ancillary services are discussed above in connection with that rule.

The rule before us here allows the Commission to "require an electric company to provide ancillary services to facilitate direct access to consumers." It further requires that the ancillary services provided must be comparable to the services that the electric company provides to its own consumers. The rule's reach is limited to those ancillary services that "are not within the exclusive jurisdiction of the Federal Energy Regulatory Commission."

PG&E views this rule, along with OAR 860-038-0410 - Scheduling, as the keys to the successful development of a competitive retail electricity market in Oregon. It argues that an incumbent utility "by denying or constraining access to the transmission system for its competitors, or providing preferential access and pricing to its own affiliates, can effectively eliminate the development of a competitive market." It notes that these issues, including fair competition in ancillary services, access to transmission, and scheduling, go beyond the scope of proposed rules on ancillary services and scheduling. It supports Staff's proposal to address these additional issues in a later rulemaking proceeding on a "Code of Conduct."

Portland generally supports PG&E's view of this rule. It also argues that the proposed rule should address self-supply of ancillary services. It notes that the rule does not address unmetered loads, such as those related to streetlights and traffic signals. It anticipates becoming a large commercial customer under direct access but feels it cannot manage and control its power costs without some provision in the rules for unmetered loads. It fears that the collection of unmetered loads inside the city will not be treated as a single load for the purposes of direct access, self-supply of ancillary services, and choice of suppliers. It asks, therefore, that the definition of "retail electricity customer" be expanded to include "a collection of unmetered loads, such as streetlights and traffic signals, . . ."

Portland also asks that the self-supply option be clearly defined, that companies be required to facilitate self-supply and integration of retail direct access with wholesale open access, and that Section (4) of the proposed rule define "own retail electricity consumers" for purposes of comparing the ancillary services the company provides to its own consumers with those provided to facilitate direct access.

Staff answers Portland's criticisms by pointing out that if the City chooses direct access from a supplier other than PGE and PacifiCorp to serve the traffic signal and traffic light loads, it may negotiate whatever deal it can. Staff notes that the proposed rule does not prohibit self-provision of ancillary services where both the customer and the control area operator agree on its appropriateness. Staff points out, however, that self-provision is not appropriate in all cases. Staff has modified OAR 860-038-0260 to meet Portland's request that companies be required to facilitate self-supply and integration of retail direct access with wholesale direct access.

Commission Disposition

The Commission adopts Staff's proposed rule. The definition of ancillary services in OAR 860-038-0005(4) allows for inclusion of additional services if appropriate. We agree that there are transmission related issues that need further development. We believe Staff has reasonably addressed the concerns of Portland relating to metering and self-provision of services.

OAR 860-038-0360 - Electric Company Customer Metering Requirements[4]

Sections (1) and (3) of this rule set out the duties of electric companies to provide meters and metering services to retail electricity consumers. Section (2) requires an electric

[4] Portland, in its comments on the original Draft Order, notes that the rule is "still silent on service to unmetered loads where avoiding the costs of installing meters is in the public interest." Examples provided by Portland include street lighting and traffic signals. Portland suggests an addition to OAR 860-038-0360 to direct electric companies to make provision for such service.

company to provide its results of meter readings to the customer's ESS in a timely manner comparable to the electric company's own provision of such information to itself, its affiliates, and related parties. Section (4) requires the electric company to provide meters and metering service necessary for an ESS to provide services to a retail customer. It also allows an ESS to request additional meter capabilities or functions subject to the approval or denial of the request by the electric company. If the request is denied, the ESS may appeal to the Commission.

Commission Disposition

Most of the participants in this case are in general agreement with Staff's final proposed rule on metering. We believe the proposed rule is appropriate and adopt it. We have addressed Portland's concern in our discussion above of OAR 860-038-0340.

OAR 860-038-0400 - Electricity Service Supplier Certification Requirements

This rule sets out procedures and standards for initial certification of ESSs and for renewal and revocation of certification. Renewal of the certificate will be accomplished if the ESS files a timely and complete application and the Commission either grants the renewal or takes no action. The rule sets out a non-exclusive list of grounds for revocation of the certification by the Commission. The rule also requires that the ESSs be certified as either scheduling or nonscheduling. Subsection (7) relates to federal system benefits available from the Bonneville Power Administration (BPA) to residential and small farm consumers. Staff and the Eugene Water & Electric Board agreed to a modification of Staff's original proposal to ensure that the rule does not inadvertently impact the ability of an ESS to access federal system benefits for consumers not receiving service from an investor-owned utility.

The rule also describes the duties of an ESS that owns, operates, or controls electrical supply lines facilities to maintain the plant and system so that "it will furnish safe, adequate, and reasonably continuous service." The rule also establishes that an ESS must give notice to the Commission of certain incidents involving serious injury, loss of life, or serious property damage occurring in Oregon at the ESS's premises or arising from or connected with the maintenance of the ESS.

PGE finds substantial fault with Staff's proposal. It suggests that, in addition to a Commission certification process, electric companies should be allowed to employ a "registration" process, as is done in some other states. Under such a system, the electric companies would determine whether an ESS is scheduling or non-scheduling. This process would eliminate a problem which might arise if the Commission gives the "scheduling" label to an ESS which claims it wants to work with only one electric company. If, PGE asks, the ESS then seeks to work with a second electric company, would the second company be obliged to accept the ESS as a scheduling ESS even though there might be significant differences between the processes of the two electric companies relating to scheduling?

If the registration requirement is not added to the rule, PGE asks that the proposed rule be modified to allow the electric company to specify that the ESS must provide additional information relating to its technical competence and ability to comply with the requirements relating to scheduling set out in OAR 860-038-0410 - Scheduling. PGE also asks that the rule allow electric companies to require the ESS to name the electric company on the ESS's insurance policy and provide a certificate of insurance to that effect. PGE also questions the provisions in the proposed rule relating to decertification and maintenance of plant by ESSs, claiming that the processes and standards are not clear and comprehensive.

PacifiCorp questions Subsection (6)(c) of the proposed rule, which requires the ESS to attest that it will, "cover creditors for a minimum of 30 days from the date of cancellation." PacifiCorp argues that it will take more than 30 days for an electric company to "true up its control area." PacifiCorp asks that the 30-day provision be changed to 90 days.

PG&E asserts that Section (12) of the proposed rule (relating to the ESS's obligation to properly maintain its plant and system) might confer new inspection authority on the Commission in relation to ESS-owned facilities. If so, PG&E asserts, the Commission should open a separate rulemaking to deal with this issue.

Commission Disposition

The Commission concludes that PacifiCorp's request for a longer period for covering losses is reasonable. We will alter Subsection (6)(c) of the proposed rule to allow for a 90-day period. PG&E's concern about "new inspection authority" appears unfounded. We see nothing in the rule that attempts to confer new inspection authority on the Commission or Staff.

PGE's proposal that we adopt a dual system involving ESS certification by the Commission and ESS registration by the electric companies is thoughtful. However, we do not believe it is necessary. The proposed rule provides a basis for a thorough review of the qualifications and classification of ESSs. The rule does not prevent, and we are certain does not intend to prevent, electric companies from offering information and views as to the suitability and capability of those applying for certification. It also allows electric companies to participate directly in the renewal and revocation processes through the complaint process. We believe the proposed rule will protect the interests of electric companies while providing an efficient method for consideration of applications, renewals, and proposed revocations of certificates. We will review the process on a continuous basis to see if changes are needed.

With the one change noted, we conclude that the rule is appropriate and meets the needs of the Commission and the affected parties. We adopt the rule as modified, including the Staff and EWEB agreed-upon language in Section (7) relating to federal system benefits.

OAR 860-038-0410 - Scheduling

This rule provides that each ESS shall be certified as either scheduling or non-scheduling. It then sets out the obligations and duties of the scheduling ESSs.

PGE has some of the same reservations regarding this rule as it had with respect to OAR 860-038-0400 - Electricity Service Supplier Certification Requirements. It believes that scheduling issues should be resolved through an individual electric company's registration process. If the Commission adopts the process set out in Staff's proposed rule, PGE suggests several changes for purposes of completeness and clarification. Other than PGE's criticism, Staff's proposed rule did not occasion dispute. As noted above under our discussion of OAR 860-038-0340, PG&E raised issues relating to transmission which Staff has agreed to consider in a rulemaking relating to a Code of Conduct.

Commission Disposition

For the reasons set out above, we will not implement PGE's request for a dual certification/registration process. We also conclude that the proposed rule is clear and needs no further definition at this time. We approve Staff's proposal relating to a Code of Conduct. It will allow for consideration of issues relating to scheduling as well as ancillary services. Our recently opened docket AR 390 will consider those subjects.

OAR 860-038-0420 - Electricity Service Supplier Consumer Protection

This rule establishes general requirements for advertising and marketing activities by ESSs. It also sets out detailed procedures required when an ESS discontinues service to a consumer. Separate notification requirements apply to the consumer and to the serving electric company. The rule also provides that a customer of an ESS may agree, through written contract, to arrangements other than those set out in the rule, provided certain requirements are met.

Commission Disposition

Staff's proposed rule provides a sound basis for protection of consumers. It did not occasion serious objection. It is adopted.

OAR 860-038-0445 - Coordination of Supplier Changes and Billing

This rule applies to ESSs and to electric companies providing service options to nonresidential consumers. It describes the process for selection of an ESS by a consumer and for changes in supplier. It also provides that a consumer will receive a consolidated bill from the electric company unless the consumer chooses to receive separate bills from each supplier or a consolidated bill from an ESS. The rule also provides, in Section (18), that the party contracting with the electric company for delivery of services is the one obligated to pay the electric company's transmission and distribution charges. If an ESS is a contracting party, failure of the customer to pay the full amount of the ESS's charges does not relieve the ESS of its obligation to pay the electric company for delivery services. The rule also provides a method of allocation of payments and provides that services subject to the Commission's jurisdiction may not be discontinued, disconnected, or placed in jeopardy because of non-payment of unregulated charges.

PacifiCorp expresses some concern about Section (18) of the proposed rule, which, as noted above, sets out the requirement that the party contracting with the electric company for delivery of services is obliged to pay the transmission and distribution charges. PacifiCorp notes that wording of this section suggests that an ESS may be the purchaser of distribution services from an electric company. PacifiCorp notes that FERC has stated that it will assert jurisdiction over local distribution facilities where an ESS has purchased distribution services over the facilities. Thus, according to PacifiCorp, if an ESS purchases transmission and local distribution services as part of an unbundled retail access program, the use of both the transmission and the distribution facilities becomes subject to FERC's jurisdiction. If the end-use consumer purchases transmission and local distribution service, the use of the transmission facilities is subject to FERC's jurisdiction and the use of the distribution facilities is subject to state jurisdiction. This situation could, according to PacifiCorp, "create difficulties when consumers switch between an ESS and Default or Standard Service by an electric company, since the jurisdiction over the distribution services would also change." PacifiCorp recommends that the Commission make clear in the rules its intent and its expectation regarding its jurisdiction over distribution services.

PGE asks that the reference in Section (18) to transmission charges be removed, as such services will be provided under a FERC tariff and are thus not within the Commission's authority. It also asks that the rule specify clearly, in Section (18), that "when the ESS is providing the consolidated bill, it will be considered to be the contracting party for distribution services" and thus liable for those charges. This would clear up an ambiguity in the proposed rule, according to PGE.[5]

PG&E proposed several changes to Staff's prior version of this proposed rule. It appears that most of them are adopted in substance by the present proposed rule. PG&E proposes certain time requirements relating to acceptance or rejection of the Direct Access Service Request (DASR) by the electric company. They require that an ESS must obtain acceptance of its DASR from the electric company at least 10 business days prior to the effective date of the change and that an electric company must accept or reject each DASR within three business days and, if the DASR is accepted, must notify the current supplier within three business days. Staff has apparently agreed with this request and has included the suggested provisions in its proposed rules.

Commission Disposition

The Commission adopts this rule as set out by Staff. We do not feel it necessary to provide additional discussion in the rule of the jurisdictional aspects of transmission and distribution. We also do not feel it necessary to specifically attempt to delineate an ESS's obligation to pay transmission and distribution charges. We believe the proposed rule is sufficiently clear on that point.

We agree with the PG&E and Staff recommendation as to explicit time frames for acceptance or rejection of the DASR. We think they will be helpful to the parties and will clarify obligations and requirements. They are contained in Sections (8) and (9) of the attached proposed rules.

[5] In its comments on the original Draft Order, PGE continues to maintain that an ambiguity exists in the rule. It proposes that the second sentence in OAR 860-038-0445(18) be modified to read, "The ESS is the contracting party when it provides a consolidated bill, and the direct access customer's failure to pay . . ."

OAR 860-038-0480 - Public Purposes

This rule sets out the requirement that electric companies, and ESSs that provide electricity services to direct access consumers in the electric company's service territory, collect public purpose charges from their retail electricity consumers 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. The collection will continue for 10 years, beginning on the date direct access is first offered. The rules contain special provisions for aluminum plants, requiring them to pay a public purpose charge equal to 1 percent of the total revenue from the sale of electricity service to the plant from any source. The rule also sets out the standard by which certain self-directing consumers may receive credits against their public purpose charges for qualified expenditures. We understand that the Office of Energy is establishing rules and procedures consistent with our rules for qualifying a self-directing consumer and for determining the implementation of the credit process.

Sections (10) and (11) set out the allocation of funds and certain accounting requirements.

ICNU raised several issues relating to public purposes. It summarizes its positions as follows:

(a) Beginning on the effective date of direct access, all public purpose costs should be removed from rates and funded exclusively through the public purpose charge;

(b) Self-directed credits should be capped at 82 % of the public purpose charge, rather than the 73.8 % level proposed by Staff; and

(c) Regardless of the percentage cap adopted by the Commission, the cap should be imposed on a cumulative basis.

Public Purpose Costs. ICNU argues that Staff's proposed rules, which would treat demand side management (DSM) assets existing as of October 1, 2001, as stranded costs to be recovered through transition charges, is inconsistent with SB 1149. According to ICNU, the law intends that after October 1, 2001, public purposes would be funded exclusively through the 3 percent public purpose charge. It argues, moreover, that Staff's proposed rule would violate the provisions of ORS 757.612(3)(f) requiring that large electric consumers not be required to pay a public purpose charge in excess of 3 percent of its total cost of electricity services because the transition charge related to past DSM investments would be over and above the 3 percent public purpose charge.

Staff disagrees with ICNU. It points out that ORS 757.612(3)(g) requires that the Commission remove from electric company rates "any costs for public purposes described in subsection (1) of this section that are included in rates . . . effective on the date that the electric company begins collecting public purpose charges." Staff notes that subsection (1) of

ORS 757.612 requires that "new" public purpose activities be funded. Staff argues that this wording limits funding to activities occurring after the beginning of direct access. Therefore, the rate removal provision of subsection (3) does not include historical capitalized DSM expenditures.

Staff also points out that rates are based on future test periods and that utilities' rates have included DSM amortization expenses related to both historical expenditures and forecasted test period expenditures, as well as non-capitalized DSM expense for such activities as program evaluation. Thus, ICNU's argument that Staff's position renders ORS 757.612(3)(g) a nullity is incorrect.

Staff claims that ICNU's interpretation would lead to inequitable results. Large consumers, by self-directing the conservation portion of their public purpose charges, would avoid payment for existing DSM cost recovery, thereby "shifting recovery to the remaining consumers that are unable to receive credits for conservation expenditures in their residences and businesses." Recovery of historical DSM expenditures that were incurred to benefit all utility consumers should be made equitably from all customer classes through the transition charges.

Amount of Cap/Cumulative Cap. ICNU claims that the proposed rules would lead to a cap on self-directed credits of 73.8 percent, a figure inconsistent with the 82 percent cap established by SB 1149. ICNU thus proposes new allocation figures to alter the cap. ICNU also argues that, whatever the amount of the cap, it should be applied on a cumulative basis. It asserts that the "plain language" of ORS 757.612(5)(a) supports its position. That provision, according to ICNU, was intended to "provide that a self-directing consumer could take a credit for up to 68% of the public purpose charge for conservation, and up to 19% of the public purpose charge for renewable resources, provided that the total credit could not exceed" the total cap (82 percent in ICNU's view, 73.8 percent in Staff's view). ICNU acknowledges that the proposed rules do not take a stance on this issue but asks that they be modified to do so.

Staff argues against the cap proposed by ICNU. It points out that if the allocations proposed by ICNU were adopted, the same factors should apply to all consumers. As a result, self-directing consumers would be eligible to self-direct a maximum of 72 percent of their public purpose charges.

Commission Disposition

The Commission believes that this rule provides a well-organized and appropriate procedure for dealing with the public purposes issue. However, we believe the issues raised by ICNU involve interpretation of SB 1149. We have requested that our legal counsel consider these issues and report to us as soon as practicable. We will then act on that advice and decide whether the rule as discussed in this order can be adopted or whether it needs to be modified.

OAR 860-022-0040 - Relating to City Fees, Taxes, and Other Assessments for Electric, Gas, and Steam Utilities

Staff's proposal is an amendment to an existing rule. It adds a Section (3) relating to volumetric-based privilege taxes or fees and provides that an amount equal to the base volumetric rates multiplied by the corresponding amount of electric energy in kilowatt hours delivered in the 12-month period used to determine a utility's revenue requirement shall be allowed as operating expenses and shall not be itemized or billed separately. No opposition to this rule in its final proposed form was offered.

Commission Disposition

The Commission adopts Staff's proposal for amendment of this rule as set out in Appendix A to this order.

ORDER

IT IS ORDERED that:

1. The rules set out in Appendix A, attached to and made part of this order, are adopted.

2. The rules shall become effective upon filing with the Secretary of State.

Made, entered, and effective ____________________________.

Ron Eachus Chairman	**Roger Hamilton** Commissioner
	Joan H. Smith Commissioner

A person may petition the Commission for the amendment or repeal of a rule pursuant to ORS 183.390. A person may petition the Court of Appeals to determine the validity of a rule pursuant to ORS 183.400.

DIVISION 038

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 utility in this state.

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

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

860-038-0005
Definitions

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) "Advisory committee" means a group appointed by the Commission, consisting of representatives from Commission Staff, the Office 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) "Aggregate" means combining retail electricity consumers into a buying group for the purchase of electricity and related services. "Aggregator" means an entity that aggregates.

(4) "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.

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

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

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

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

(9) "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.

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

(11) "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.

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

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

(14) "Economic utility investment" means all Oregon allocated investments made by an electric company prior to the date the electric company 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 ORS 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.

(15) "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.

(16) "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.

(17) "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.

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

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

(20) "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.

(21) "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.

(22) "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.

(23) "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, or any different level of consumption as may be established by the Commission pursuant to the proceeding identified in OAR 860-038-0080(5)(a).

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

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

(26) "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.

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

(28) "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.

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

(30) "Net system power 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 Office of Energy.

(31) "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.

(32) "New renewable energy resource" means a renewable energy resource project or a new addition to an existing renewable energy resource project, or the electricity produced by the project, that was not in operation on or before July 23, 1999. "New renewable energy resource" does not include any portion of a renewable energy resource project under contract to the Bonneville Power Administration on or before July 23, 1999.

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

(34) "Office of Energy" means the Oregon Office of Energy created under ORS 469.030.

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

(36) "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.

(37) "One average megawatt" means 8,760,000 kilowatt-hours of electricity per year.

(38) "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.

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

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

(41) "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 Office of Energy may establish by rule a limit on the maximum above-market cost for renewable energy that is allowed as a credit.

(42) "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 Division but is not the subject of a formal complaint.

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

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

(45) "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.

(46) "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.

(47) "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 company on or after July 23, 1999, whether or not each end user purchases the electricity from the electric company. 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 October 1, 2001, at the site.

(48) "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 Office 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.

(49) "Serious injury to person" means, in the case of an employee, an injury that results in hospitalization. In the case of a nonemployee, "serious injury" means any contact with an energized high-voltage line, or any incident that results in hospitalization. Treatment in an emergency room is not hospitalization.

(50) "Serious injury to property" means damage to ESS and non-ESS property exceeding $25,000 or failure of ESS facilities that causes or contributes to a loss of energy to consumers.

(51) "Site" means a single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, or 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.

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

(53) "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.

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

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

(56) "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.

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

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

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

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

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

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

(63) "Uneconomic utility investment" means all Oregon allocated investments made by an electric company prior to the date the electric company 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 ORS 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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stat. Implemented: ORS 756.040. 757.600 to 757.667
Hist.: NEW

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) 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 residential and small nonresidential 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 Oregon large nonresidential consumers' share of an electric company's generating resources;

(b) The Commission will not require an electric company to acquire new generating resources except as provided in ORS 757.663. Major capital improvements to existing generating resources will continue to 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. Electric companies must include new generating resources in revenue requirement at

market prices, and not at cost, and such new generating resources will not be added to an electric company's rate base even if owned by the electric company;

(c) 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.

(d) 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, the Oregon large nonresidential 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 in the 12 months ending September 30, 2001, to total Oregon retail load measured in weather-normalized kilowatt-hour sales in the 12 months ending September 30, 2001. To the extent such shares are not known as of October 1, 2001, the electric company will use estimates until relevant data are available.

(3) On or before November 1, 2000, 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 Oregon residential and small nonresidential consumers' share of the electric company's load, and the amount that is attributable to the Oregon large nonresidential consumers' share of the electric company's load;

(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 residential and small nonresidential 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 the 12 months ending September 30, 2001, 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 residential and small nonresidential 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 residential and small nonresidential 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 rates filed by the electric company on October 1, 2000; and

(iii) An estimate of the cost-of-service rates for Oregon residential and small nonresidential 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 schedule in the contested case proceeding must be set to produce a Commission decision on the resource plan by April 1, 2001. The Commission's order must identify those resources that, at the option of the electric company, may be auctioned immediately, 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. Until a resource plan is approved by the Commission, the ongoing valuation method described in OAR 860-038-0140 will be used to establish transition charges and credits.

(5) An electric company or any nonresidential consumer may propose to change the definition of "large nonresidential consumer" provided in OAR 860-038-0005(23), by making a written request to the Commission no later than October 15, 2000, in which case the following shall apply;

(a) The Commission shall initiate a proceeding open to all interested parties to determine on an expedited basis whether to change the definition of "large nonresidential consumer." The schedule shall be set to obtain a Commission decision on this issue as soon as practical prior to March 1, 2001.

(b) The Commission shall only change the definition of "large nonresidential consumer" if the Commission determines it is in the public interest based on the following factors, and such other factors as the Commission deems relevant:

(A) Each electric company may have the same definition of large nonresidential consumer;

(B) For each class of consumers deemed "large nonresidential consumers," prices for electricity services, taking into account transition charges, transition credits, and incentive payments, if any, should not materially exceed prices for electricity services such class of consumers would pay under a cost-of-service rate;

(C) Consistent with ORS 757.646, the Commission should define large non-residential consumers to encompass as many nonresidential consumers as is feasible; and

(D) The potential benefits available due to new products, service options, and product innovations.

(c) Notwithstanding section (5) of this rule, each electric company shall file its resource plan on November 1, 2000, based on the definition of "large nonresidential consumer" contained in OAR 860-038-0005. In the event the Commission modifies the definition of "large nonresidential consumer" pursuant to section (5) of this rule, each electric company shall promptly modify its resource plan to reflect such change; and

(d) Each electric company shall identify the changes that would be necessary to implement any alternate definition of "large nonresidential consumer" proposed by a party to the proceeding initiated pursuant to this section (5) of this rule.

(6) 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 electric company must implement the Resource Plan consistent with OAR 860-038-0100 and a process for administrative valuation to be specified by rule. Until a Resource Plan is implemented, including the establishment of final values for generating resources, the electric company must determine transition charges and credits using an ongoing valuation method permitted under OAR 860-038-0140.

(7) 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 October 1, 2001, through December 31, 2002:

(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, 2003, transition charges and transition credits will be calculated without regard to subsection (7)(b) of this rule.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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 residential and small nonresidential consumers until otherwise directed by the Commission. Except in the circumstances set forth in OAR 860-038-0080(6) and (7), an electric company will not use an ongoing valuation method to determine the transition charges or transition credits applicable to Oregon large nonresidential consumers.

(2) Each electric company will propose one or more ongoing valuation methods in the rate filings required pursuant to OAR 860-038-0240(5). 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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

860-038-0160
Transition Costs and Credits

(1) Except as provided for in OAR 860-038-0080(7), 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 will not change based on the service option chosen by the consumer.

(2) The Oregon residential and small nonresidential consumers of that electric company will bear the entire revenue requirement of generating resources, or portions thereof, retained in an electric company's Oregon revenue requirement for the purpose of serving Oregon residential and small nonresidential consumers. In addition, the electric company will:

(a) Collect from Oregon residential and small nonresidential consumers the funds necessary to provide any transition credits related to such resources to Oregon large nonresidential consumers exclusive of incentive payments; or

(b) Credit to Oregon residential and small nonresidential consumers the funds received from any transition charges related to such resources from Oregon large nonresidential 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 October 1, 2001, 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 October 1, 2001, 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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

860-038-0220
Portfolio Options

(1) By October 1, 2001, an electric company must provide each residential consumer who is connected to its distribution system with a portfolio of product and pricing options. 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) The Advisory Committee, as defined in OAR 860-038-0005, will recommend portfolio options to the Commission for the 15-month service period beginning October 1, 2001, and the 12-month service period beginning January 1, 2003, and each calendar year thereafter. The Advisory Committee will make its recommendations six months prior to the date of implementation of the portfolio product and pricing options each year. The Commission is not bound by the recommendations of the Advisory Committee.

(4) The portfolio must include at least one product and rate that reflects renewable energy resources and one market-based rate. The Advisory 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 Advisory 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) Residential consumers may choose the cost-of-service rate option or a portfolio option in August for the 15-month service period beginning October 1, 2001. Beginning October 1, 2002, and each year thereafter, the residential consumer may choose the cost-of-service rate option or a portfolio option in October for the 12-month service period beginning January 1. A residential consumer who does not make an affirmative choice in the open enrollment period will be assigned to the option under which service is currently received. If the option the residential consumer is currently receiving is not available in the next service period, the consumer who does not make an affirmative choice in the enrollment period will be assigned to the cost-of-service rate option. The Advisory Committee may recommend an alternative enrollment process to the Commission, including but not limited to continuous open enrollment, but in no case may market rate participants change options more frequently than once per year.

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

(9) 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.

(10) This section applies to small nonresidential portfolio product and pricing options. The Advisory 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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

860-038-0240
Cost-of-Service Rate

(1) By October 1, 2001, an electric company must provide a cost-of-service rate option to residential and small nonresidential consumers. Only one cost-of-service rate option may be offered by schedule to each class of customers. A cost-of-service rate option will not be offered to large nonresidential 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 customer 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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

860-038-0250

Nonresidential Standard Offer

(1) By October 1, 2001, 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 based on supply purchases made on a competitive basis from the wholesale market plus the transition credit or transition charge 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.

(3) Large nonresidential retail electricity consumers that do not choose direct access will automatically receive standard offer service beginning October 1, 2001. After October 1, 2001, new large nonresidential consumers will be served under the standard offer rate if they do not elect direct access.

(4) The electric company must design its cost-of-service rate and one-time charges associated with returning to a cost-of-service rate so that consumers served under a cost-of-service rate are not harmed by other consumers switching between direct access or standard offer and the cost-of-service rate.

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

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

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

Stat. Auth.: ORS Ch. 183, 756 & 757

Stats. Implemented: ORS 756.040 & 757.600 through 757.667

Hist.: NEW

<u>**860-038-0260**</u>
<u>**Direct Access**</u>

<u>**(1) By October 1, 2001, an electric company must allow nonresidential consumers to choose direct access.**</u>

<u>**(2) An electric company must develop direct access rates as follows:**</u>

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

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

<u>**(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;**</u>

<u>**(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;**</u>

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

<u>**(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.**</u>

<u>**(3) The electric company must design its cost-of-service rate options and one-time charges associated with returning to a cost-of-service rate so that consumers served under a cost-of-service rate option are not harmed by other consumers switching between direct access or standard offer and the cost-of-service rate.**</u>

<u>**(4) After October 1, 2001, 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.**</u>

<u>**(5) Operation of a special contract approved by the Commission prior to October 1, 2001, between an electric company and a retail electricity consumer that extends beyond October 1, 2001, will be governed by the terms of the contract.**</u>

<u>**(6) Line extension charges must be independent of the power supply option elected by a retail electricity consumer.**</u>

<u>**(7) 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:**</u>

<u>**(a) Definitions of services;**</u>

<u>**(b) Rules for application for direct access service, including notice periods;**</u>

<u>**(c) Rules for switching among forms of service, including notice periods;**</u>

<u>**(d) Termination rights;**</u>

<u>**(e) Dispute resolution;**</u>

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

<u>**(g) Billing and payment;**</u>

<u>**(h) Liability and indemnification;**</u>

<u>**(i) All necessary service schedules and technical requirements; and**</u>

<u>**(j) Other provisions that the Commission determines are reasonable and necessary for direct access.**</u>

(8) 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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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 a minimum of five business days' notice of intent to purchase or terminate purchase of standard offer service.

(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 OAR 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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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) For each service or product it offers, an electric company must provide price, power source, and environmental impact information to all residential consumers at least quarterly. The information must be based on the available service options. The information must be supplied using a format prescribed by the Commission. An electric company must also include on every bill a URL address, if available, for a world-wide web site where this information is displayed. The electric company must report price information for each service or product for residential consumers as the average monthly bill and price per kilowatt-hour for monthly usage levels of 250, 500, 1,000 and 2,000 kilowatt-hours, for the available service options.

(3) An electric company and an electricity service supplier must provide price, power source and environmental impact information on or with bills to nonresidential consumers using a format prescribed by the Commission. The electric company or electricity service supplier must provide a URL address, if available, for a world-wide web site that displays the power source and environmental impact information for the products sold to consumers. An electric company and an electricity service supplier must report price information for nonresidential consumers on each bill 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.

(4) 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 net system power 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. For net market purchases, the electric company must report power source and environmental impact information based on the net system power mix. The electric company must report power source and environmental impact information for standard offer sales based on the net system power mix.

(5) For purposes of power source and environmental impact reporting, an ESS should use the net system power mix for the current calendar year unless the ESS is able to demonstrate a different power source and environmental impact. An ESS 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 fuels including but not limited to new renewable resources, if over 1.5 percent of the total fuel mix.
(6) 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) Spent nuclear fuel measured in mg/kWh of spent fuel.
(7) Every bill to a direct access consumer must contain the ESS'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.
(8) The ESS must provide price, power source, and environmental impact in all contracts and marketing information.
(9) The electric company must provide price, power source, and environmental impact in all standard offer marketing information.
(10) Beginning April 1, 2003, and on April 1st thereafter for the prior calendar year, each electric company, and each ESS making any claim other than net system power mix, must file a reconciliation report on forms prescribed by the Commission. The report must provide a comparison of the fuel mix and emissions of all of the seller's certificates, purchase or generation with the claimed fuel mix and emissions of all of the seller's products and sales.
(11) Each ESS 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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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) At a minimum, an ESS applicant must provide 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) Financial statements and credit reports;
(g) Information documenting technical competence;
(h) Identification of the services and products intended to be offered; and
(i) Identification of targeted customer class(es) and geographical area;
(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 ESS must state that all information provided is true and correct and sign the application.
(6) At a minimum, an ESS 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) 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.
(9) 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 submit 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), (h), (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 (10) of this rule. The renewal applicant will be considered temporarily certified during the pending revocation proceeding.

(10) 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.

(11) 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.

(12) 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 to the Commission.

(a) Every ESS must give immediate notice to the Commission by telephone, FAX, e-mail, or in person of incidents attended by loss of life or limb or serious injury to person or property occurring in Oregon upon the premises of or directly or indirectly arising from or connected with the maintenance or operation of the ESS; and

(b) In addition to the immediate notice required in subsection (12)(a) of this rule, the incident must be reported in writing to the Commission within 20 days of the occurrence using a format prescribed by the Commission.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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 Systems 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.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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) Sections (7) through (10) of this rule apply to any alleged violation of the rules in Division 038 applicable to electricity service suppliers.

(a) When a dispute occurs between an ESS and its consumer about any bill, charge, or service, the electricity service supplier must acknowledge the dispute with a response to the consumer within five calendar days. The ESS must thoroughly investigate the matter and report the results of its investigation to the ESS consumer within 15 calendar days. If the ESS is unable to resolve the matter with its consumer within 15 calendar days, the ESS must advise the consumer 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 at 1-800-522-2404; TDD 1-800-648-3458; or at 550

Capitol Street NE, Suite 215, Salem, Oregon 97301-2551. 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 electricity service supplier 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 with the Commission. The complaint must state the facts of the dispute and the relief requested. The electricity service supplier must answer the complaint within 15 calendar days of service of the complaint. The matter will then be set for expedited hearing. A hearing may be held on less than 10 calendar days' notice when good cause is shown.

(8) Within the terms of a written contract, a consumer 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:

(1) An electric service supplier (ESS) must give its customers at least 10 business days' written notice before the ESS may discontinue service.

(2) 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.

(3) The electricity service supplier 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.

(4) Not less than 10 business days prior to discontinuance of service to an ESS customer, the electricity service supplier must notify the serving electric company, by mutually acceptable means, that the electricity service supplier will no longer be supplying energy to that ESS customer. If an electricity service supplier 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.

THIS MAY AFFECT YOUR ABILITY TO ARRANGE FOR OTHER ENERGY SERVICE.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 757.600 through 757.667
Hist.: NEW

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 Consumer Services Division at 1-800-522-2404; TDD 1-800-648-3458; or at 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551. 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.

Stat. Auth.: ORS Ch. 183, 756 & 757

Stats. Implemented: ORS 756.040 & 757.600 through 757.667

Hist.: NEW

860-022-0040

Relating to City Fees, Taxes, and Other Assessments for Electric, Gas, and Steam Utilities

(1) The aggregate amount of all business or occupation taxes, license, franchise or operating permit fees, or other similar exactions**, excepting volumetric-based fees in section (3) of this rule,** imposed upon gas, electric, or steam utilities by any city in Oregon for engaging in business within such city or for use and occupancy of city streets and public ways, which does not exceed 3 percent for gas utilities or 3.5 percent for electric and steam utilities, applied to gross revenues as defined herein, shall be allowed as operating expenses of such utilities for rate-making purposes and shall not be itemized or billed separately.

(2) Except as otherwise provided herein, "gross revenues" means revenues received from utility operations within the city less related net uncollectibles. Gross revenues of gas, electric, and steam utilities shall include revenues from the use, rental, or lease of the utility's operating facilities other than residential-type space and water heating equipment. Gross revenues shall not include proceeds from the sale of bonds, mortgage or other evidence of indebtedness, securities or stocks, sales at wholesale by one utility to another when the utility purchasing the service is not the ultimate customer, or revenue from joint pole use.

(3) Each electric utility subject to volumetric-based privilege taxes or fees shall determine for each city imposing such volumetric charges a base volumetric rate for each customer class calculated as 3.5 percent of the class 1999 gross operating revenues within the city divided by the amount of electric energy in kilowatt-hours delivered to the class in 1999. In cases where 1999 data is not available for a particular city and/or class, the utility's total 1999 Oregon revenues and kilowatt-hour deliveries for the customer class shall be used to calculate the base volumetric rate. An amount equal to the base volumetric rates multiplied by the corresponding amount of electric energy in kilowatt hours delivered in the 12-month period used to determine the utility's revenue requirement shall be allowed as operating expenses and shall not be itemized or billed separately. The privilege tax shall be allocated across an electric company's customer classes in the same proportional amounts as levied by cities against the electric company.

~~(3)~~**(4)** Permit fees or similar charges for street opening, installations, construction, and the like to the extent such fees or charges are reasonably related to the city's costs for inspection, supervision, and regulation in exercising its police powers, and the value of any utility services or use of facilities provided on November 6, 1967, to a city without charge, shall not be considered in computing the percentage levels ~~herein~~ set forth **in sections (1) and (3) of this rule**. Any such services may be continued within the same category or type of use. The value of any additional category of utility service or use of facilities provided after November 6, 1967, to a city without charge shall be considered in computing the percentage levels herein set forth.

~~(4)~~**(5)** This rule shall not affect franchises existing on November 6, 1967, granted by a city. Payments made or value of service rendered by a utility under such franchises shall not be itemized or billed separately. When compensation different from the percentage levels in section (1) of this rule is specified in a franchise existing on November 6, 1967, such compensation shall continue to be treated by the affected utility as an operating expense during the balance of the term of such franchise. Any tax, fee, or other exaction set forth in section (1) of this rule, unilaterally imposed or increased by any city during the unexpired term of a franchise existing on November 6, 1967, and containing a provision for compensation for use and occupancy of streets and public ways, shall be charged pro rata to local users as herein provided.

~~(5)~~**(6)** Except as provided in section ~~(4)~~ **(5)** of this rule, to the extent any city tax, fee, or other exaction referred to in section**s** (1) **and (3)** of this rule exceeds the percentage levels allowable as operating expenses in section**s** (1) **and (3)** of this rule, such excess amount shall be charged pro rata to utility customers within said city and shall be separately stated on the regular billings to such customers.

~~(6)~~**(7)** The percentage levels in section**s** (1) **and (3)** of this rule may be changed if the Commission determines after such notice and hearing, as required by law, that fair and reasonable compensation to a city or all cities should be fixed at a different level or that by law or the particular circumstances involved a different level should be established.

Stat. Auth.: ORS 183**,** ~~&~~ 756 **& 757**
Stats. Implemented: ORS 756.040 **& 757.600 through 757.667**
Hist.: PUC 164, f. 4-18-74, ef. 5-11-74 (Order No. 74-307); PUC 3-1990, f. & cert. ef. 4-6-90 (Order No. 90-417); PUC 14-1990, f. & cert. ef. 7-11-90 (Order No. 90-1031); PUC 7-1998, f. & cert. ef. 4-8-98; PUC 3-1999, f. & cert. ef. 8-10-99