BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

AR 651

IN THE MATTER OF RULEMAKING REGARDING DIRECT ACCESS INCLUDING 2021 HB 2021 REQUIREMENTS	COMMENTS OF BROOKFIELD RENEWABLE TRADING AND MARKETING LP

BROOKFIELD RENEWABLE TRADING AND MARKETING LP

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Dated: April 25, 2023

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I. INTRODUCTION & SUMMARY

Brookfield Renewable Trading and Marketing LP ("BRTM") hereby submits the following comments on the Oregon Public Utility Commission's ("OPUC" or "Commission") Notice of Proposed Rulemaking ("NOPR") published on February 27, 2023. BRTM appreciates stakeholder and Commission involvement in this proceeding and looks forward to developing just and reasonable rules to guide non-bypassable charges, preferential curtailment, and Electricity Service Supplier ("ESS") reporting while ensuring continued viability of directs access ("DA") in Oregon.

BRTM submits these comments to (1) propose revisions to certain definitions relating to preferential curtailment and non-bypassable charges, (2) clarify the Commission's analysis related to non-bypassable charges, and (3) recommend modification to proposed preferential curtailment rules to improve clarity and cover unaddressed issues. Redline changes to the NOPR are referenced below and reproduced in full in Exhibit A. While no further workshops or comments are currently scheduled in this proceeding, BRTM welcomes further discussion on the issues included below or in the NOPR if helpful to the Commission's decision.

I. COMMENTS

A. The definition of Preferential Curtailment and Uneconomic Cost of Implementing a Public Policy Goal warrant reconsideration or revision.

1. The definition of Preferential Curtailment should exclude reference to substantive requirements.

The proposed definition of Preferential Curtailment contains the following statement: "The electric company must curtail such consumers as necessary to protect cost-of-service customers from the impacts of the returning consumer's unplanned load."[1] Substantive rights or obligations should not be included in definitions of terms. Definitions should be limited to defining terms used in the regulation; substantive principles such as what occurs in practice when load shedding or curtailment must occur should be included in the substance of the rule itself. Put differently, the portion of the definition of Preferential Curtailment excerpted above does not define the term. Rather, the excerpt imposes an obligation on electric companies. For the sake of consistency with other definitions and to ensure that pertinent requirements can be easily located in one place (*i.e.*, the substantive rule provisions), the sentence above should be deleted from the definition.

Including a substantive obligation within a definition also creates potential for inconsistency between the definition and the substantive rule, which has occurred here. While the definition states that an electric company "*must*" curtail, proposed OAR 860-38-0290(12) states that if Uncommitted Supply is unavailable, "the electric company *may* preferentially curtail." Therefore, BRTM recommends that the excerpted sentence above be deleted from the definition of Preferential Curtailment. The electric company's obligation is already captured in proposed OAR 860-38-0290(12).

[1] NOPR, p. 5 (proposed rule language for OAR 860-038-0005(25)).

2. The definition of Uneconomic Cost of Implementing a Public Policy Goal should be clarified.

The NOPR defines "Uneconomic Cost of Implementing a Public Policy Goal" as "the difference between the cost of implementing the public policy goal and the regulated costs that are avoided as a result of implementing the public policy goal." As used in substantive sections of the NOPR, proposed OAR 860-038-0170 states that in determining whether a cost is non-bypassable, the Commission shall consider "whether it is an uneconomic cost of implementing a public policy goal *such as those identified in ORS 469A.465 or similar public policy goals* related to reliability, equity, decarbonization, resiliency or other public interest *for which retail consumers served by electricity service suppliers otherwise would not meaningfully contribute*."[2] In turn, ORS 469A.465 states, in pertinent part:

> The commission shall review and identify costs incurred by electric companies for obligations not similarly imposed on electricity service suppliers to comply with ORS 469A.400 to 469A.475 that retail electric consumers served by electricity service suppliers may avoid by obtaining electric power through direct access and ensure that the identified costs are recovered from all retail electricity consumers, are calculated and recovered on the basis of electricity consumption and bear a direct relationship to costs borne by retail electricity consumers served by electric companies.

Reading ORS 469A.465 and proposed OAR 860-038-0170(1)(b) together, "Uneconomic Cost of Implementing a Public Policy Goal" appears to concern costs utilities would incur and pass onto their customers as a result of a public policy initiative, while DA customers would avoid incurring a cost related to a similar public policy goal.[3] In other words, the existence of an Uneconomic Cost of Implementing a Public Policy Goal depends on whether and the extent to

[2] NOPR, p. 8 (proposed rule language for OAR 860-038-0170(1)(b)) (emphasis added).
[3] Proposed OAR 860-038-0170(1)(b) states that "an uneconomic cost of implementing a public policy goal" are costs "such as those identified in ORS 469A.465 or similar public policy goals … for which retail consumers served by electricity service suppliers otherwise would not meaningfully contribute." This provision is, in essence, a definition of the term different from that proposed in OAR 860-038-0005.

which bundled utility customers are incurring a cost associated with a public policy goal that DA customers are not.

However, the definition of Uneconomic Cost of Implementing a Public Policy Goal does not comport with this understanding. As a general matter, the definition is broad, and it is difficult to understand exactly which costs are included within it. The initial component of the definition—"the cost of implementing the public policy goal"—does not detail the entity incurring the cost. Is the Commission to examine a utility's costs or those of an ESS? And, the latter component of the definition—"the regulated costs that are avoided as a result of implementing the public policy goal"—similarly does not describe which entity's (or maybe customer's(s')) avoided regulated costs should be examined.

To date, discussion on this rule has included concern from certain parties that DA customers could avoid costs associated with public policy directives simply by obtaining service from an ESS. The substantive provisions of ORS 469A.465 and proposed OAR 860-038-0170(1)(b) accomplish this goal without the need to define an Uneconomic Cost of Implementing a Public Policy Goal. Specifically, with the defined term removed, OAR 860-038-0170(1)(b) would require the Commission to consider whether the charge proposed to be non-bypassable "is **a** ~~**an uneconomic**~~ cost ~~**of implementing a public policy goal such as those**~~ identified in ORS 469A.465 or similar public policy goals related to reliability, equity, decarbonization, resiliency or other public interest for which retail consumers served by electricity service suppliers otherwise would not meaningfully contribute." Eliminating the defined term would promote simplicity and

clarity, while maintaining full and fair Commission consideration of party concerns that DA customers might avoid incurring costs mandated by public policy.[4]

Therefore, BRTM recommends that the definition and usage of an Uneconomic Cost of Implementing a Public Policy Goal be removed from the proposed rules.

B. The Commission should revise the factors in OAR 860-038-0170 associated with Non-bypassable Charges consistent with Brookfield's prior comments.

As indicated in BRTM's prior comments in the informal phase of this proceeding, BRTM generally supports the language in proposed OAR 860-038-0170.[5] The language is a reasonable compromise between the competing interests of the stakeholders who have participated throughout this docket. Consistent with its prior comments, BRTM proposes several clarifying edits to the factors the Commission is to consider in determining whether a charge should be non-bypassable. Specifically, BRTM proposes the following revisions:

> (a) whether ~~it~~the charge proposed to be non-bypassable is required by statute
> (b) whether ~~it~~the charge proposed to be non-bypassable is a ~~an uneconomic~~ cost ~~of implementing a public policy goal such as those~~ identified in ORS 469A.465 or similar public policy goals related to reliability, equity, decarbonization, resiliency or other public interest for which retail consumers served by electricity service suppliers otherwise would not meaningfully contribute.
> (c) whether or not ~~it~~the utility action associated with the charge proposed to be non-bypassable confers a demonstrable electric system benefit on some customers over others
> (d) whether ~~it~~designating the charge as non-bypassable is in the public interest
> (e) whether ~~it~~the charge is necessary to be non-bypassable under the Commission's discretion in order to establish fair, just, and reasonable rates.

[4] To the extent the definition of uneconomic cost of implementing a public policy goal is intended to address costs that are not already addressed in the remainder of proposed OAR 860-038-0170(1)(b), the definition requires revision to specify exactly which sets of costs are to be compared. However, again, based on discussions to date, the definition of uneconomic cost of implementing a public policy goal does not address additional costs not already included in the remainder of proposed OAR 860-038-0170(1)(b).

[5] BRTM Comments, pp. 2-3 (Sep. 15, 2022).

BRTM believes its proposed edits are noncontroversial and clarify exactly what the Commission should examine in its non-bypassability analysis. Indeed, Commissioner Thompson expressed interest in adopting the above revisions at the Commission's Open Meeting on October 4, 2022, stating: "I did like that Brookfield language changes proposed to the rules but I don't need to necessarily – we don't need to wordsmith that today. I can just indicate that I like those comments and they're kind of already in the record perhaps."[6] Chair Decker followed up, stating: "Ya, and I think it is good to indicate that that's the direction you'd be leaning so if people have written comments during the formal phase that they should address those."[7,8] Consistent with the Commissioners' direction, BRTM reproduces its proposed edits here and respectfully requests that they be adopted.

C. Preferential Curtailment rules in proposed OAR 860-038-0290 require clarification and revision.

1. Proposed OAR 860-038-0290(4) should reference available capacity.

Currently, proposed OAR 860-038-0290(4) states that a utility cannot preferentially curtail returning DA load in the following three circumstances: (1) the returning DA customer has elected to be non-curtailable, (2) the returning DA customer's load is infeasible to curtail, and (3) curtailment of a returning DA customer's load would negatively affect cost-of-service customers. Later, in proposed OAR 860-038-0290(9), the rules state that utilities are required to make best efforts to serve a non-curtailable customer with Uncommitted Supply.

For the sake of consistency and clarity, OAR 860-038-0290(4) should include reference to OAR 860-038-0290(9). This will make clear that utilities cannot preferentially curtail when the

[6] Oregon Public Utilities Commission, Open Meeting, Comments of Commissioner Thompson at 1:39:50-1:40:05.
[7] Oregon Public Utilities Commission, Open Meeting, Comments of Chair Decker at 1:40:05-1:40:18.
[8] In making these statements, the Commissioners were referencing the changes to add clarity to the use of "it." For consistency with BRTM's comments above, BRTM also includes its proposed revision to OAR 860-038-0170(1)(b).

utility has available capacity. Accordingly, BRTM recommends the following revision to OAR 860-038-0290(4):

> (4) An electric company may not preferentially curtail the load of a direct access consumer when:
>
> (a) The direct access consumer, has elected to be non-curtailable during the election period~~, or,~~;
>
> (b) The direct access consumer's load is infeasible to curtail~~, or~~;
>
> (c) ~~When the~~The preferential curtailment of a direct access consumer would negatively affect cost-of-service consumers~~.~~; or
>
> **(d) Uncommitted Supply is available as described in section (9) of this rule.**

2. Proposed OAR 860-038-0290(7) should leave whether caps are imposed to the Commission during the contested phase of this proceeding.

Throughout the informal phase of this rulemaking, stakeholders generally agreed to reserve the propriety of caps for the contested phase of this proceeding. Recognizing the highly contested nature of DA caps, Commission Staff and stakeholders coalesced around a set of criteria to determine whether a cap is appropriate in the first instance. Specifically, Staff's Report recommending issuance of the NOPR states:

> The Commission may preserve, adjust, or impose a cap if an increase in DA load will:
>
> 1. Compromise system reliability
> 2. Shift an unacceptable amount of cost to cost-of-service customers
> 3. Pose undesirable long term financial impacts to the electric system or cost-of-service customers
> 4. Pose other unmitigated risks to cost-of-service customers[9]

[9] Staff's Revised Recommendation to Move to Formal Stage, p. 9 (dated Sep. 26, 2022).

Other materials also evidence the general understanding of Staff and stakeholders to reserve cap issues for the contested phase of this proceeding.[10] This mutual understanding was presented by utilities and ESSs alike.[11] Acknowledging this approach, Staff's most recent straw proposal included the following proposed rule: "The Commission *may* establish a cap on non-curtailable direct access load."[12] However, in the NOPR, this language was changed to: "The Commission *will* establish a cap on non-curtailable direct access load to protect cost-of-service customers from the risks and costs associated with direct access consumers' return to an electric company's system."[13] This revised language abandons the mutual understanding of the stakeholders to date and presupposes the necessity of DA caps without a robust record. As noted by PacifiCorp, "The contested case will provide a meaningful opportunity for stakeholder input on any proposed criteria and allow for Commission guidance *after factual exploration of the issue*."[14] Oregon law requires substantial evidence to support agency action,[15] and facts supporting whether and the extent to which caps are appropriate have not and cannot be presented here. Discovery and proceedings

[10] *Id.* ("In the event that DA caps are deemed necessary in the contested case…"); Staff's Comments, p. 6 (dated March 31, 2023) ("Staff anticipates that at least the following topics will be addressed over the course of the contested case: *Existence* and level of caps on Direct Access…"); Staff's Presentation for Oct 4, 2022 Public Meeting, p. 8 (dated Sep. 30, 2022) ("The guidance shouldn't be included in rules but is a good starting point for the contested case phase."); Staff's Presentation for July 12, 2022 Meeting, p. 9 (dated July 12, 2022) (declining to recommend language on caps in the rules "because of stakeholder feedback, the issue's contentiousness, and timeline limitations."); Staff's Proposed Division 38 Rule Language – AR 651, p. 28 (dated Mar. 22, 2022) ("Staff does not propose any detailed rules on caps at this time, and agrees with many of the parties' comments that the contested case phase is more appropriate to make determinations on this topic.").

[11] *See e.g.*, PGE Comments, p. 3 (dated Apr. 4, 2022) ("To the extent that any decisions are to be made on caps, PGE agrees with Staff that '[…] the contested case phase [of UM 2024] is more appropriate to make determinations on this topic.'"); NIPPC Comments, pp. 5-6 (dated Apr. 21, 2022) ("NIPPC agrees with Staff that cap issues for direct access programs should not be codified in rules at this time.").

[12] Staff's Updated Straw Proposal, p. 4 (dated Dec. 16, 2022) (emphasis added).

[13] NOPR, p. 9 (proposed rule language for OAR 860-38-0290(7)) (emphasis added).

[14] PacifiCorp Comments, p. 4 (dated Apr. 21, 2022) (emphasis added).

[15] *Calpine Energy Sols. LLC v. PUC of Or.*, 298 Ore. App. 143, 160 (2019) ("[W]e must set aside or remand the PUC's order if we find that the order is not supported by substantial evidence in the record. Substantial evidence supports the PUC's findings when the record, viewed as a whole, would permit a reasonable person to make that finding.") (citations and quotations omitted).

through a contested hearing are necessary to explore the issue fully, considering, among other things, the criteria discussed by Staff and excerpted above.

Therefore, BRTM respectfully requests that the Commission revert back to Staff's prior proposed language and reserve cap issues for the contested phase of this proceeding.

3. Returning customers should be charged only the incremental cost to serve.

The NOPR indicates that a returning DA customer (curtailable or not) would be assessed "the greater of the incremental capacity and energy costs or the retail energy market costs required to serve."[16] BRTM supports the notion that a DA customer that returns unexpectedly should compensate the utility for the incremental costs the utility incurs to serve the returning customer. However, the costs a DA customer is responsible for should be only those incremental capacity and energy costs incurred to serve them, but in no event should the cost charged to the returning customer be less than the costs that would otherwise be charged to a fully bundled, cost-of-service customer in the applicable rate schedule. If the returning DA customer is covering all incremental capacity and energy costs incurred to serve them, whether higher or lower than the retail energy price, then the returning customer is not harming cost-of-service customers. The appropriate policy choice is to require returning customers to cover demonstrable costs they cause the utility to incur, and not penalize the returning customer based on unpredictable and transient lost opportunity costs.

Further, it is not clear how "retail energy costs" will be measured. It is possible to impute the wholesale energy price at one of several trading hubs; however, retail prices do not necessarily equate to, or follow a clear defined relationship with respect to, hub prices in the wholesale market.

[16] NOPR, p. 9 (proposed rule language for OAR 860-38-0290(11), (14)).

Accordingly, there exists significant risk for discriminatory market pricing whereby a returning DA customer would simply be charged the highest "proxy" for retail energy costs. However, it is important to recognize the possibility for incremental costs to be lower than the costs that would have been charged to a fully bundled, cost-of-service customer. It is not reasonable for a returning customer to pay less than a cost-of-service customer when the returning customer is also receiving fully bundled service during their return. Therefore, for the sake of both simplicity and clarity, returning non-curtailable DA customers should only be charged the greater of the incremental capacity and energy costs or the costs that would have been charged if the customer was receiving electric service pursuant to the electric company's applicable cost-of-service rate schedule. To implement this change, BRTM proposes the following revisions:

> (11) If a returning preferentially curtailable consumer is served with Uncommitted Supply, the consumer will be charged the greater of the incremental capacity and energy costs or the **costs that would have been charged if the consumer was receiving electric service pursuant to the electric company's applicable cost-of-service rate schedule** ~~**retail energy market costs required to serve on less than the required notice of return in the electric company's direct access program tariff**~~.
> ….
> (14) If a non-curtailable consumer returns to the electric company's service without the required notice of return under an electric company's direct access program tariff, the electric company shall charge the non-curtailable consumer the greater of the incremental capacity and energy costs or the **costs that would have been charged if the consumer was receiving electric service pursuant to the electric company's applicable cost-of-service rate schedule** ~~**retail energy market costs required to serve on less than the required notice of return**~~.

4. Elections under proposed OAR 860-038-0290(13) and OAR 860-038-0290(6) should be clarified.

OAR 860-038-0290(13) in the NOPR states that "[a] preferentially curtailable consumer that returns to the electric company's service without the required notice of return under the electric company's direct access program tariff shall be subject to potential curtailment for a period equal

to the remaining time for notice of return." However, OAR 860-038-0290(6) states that "[a] consumer may change their curtailment election during the annual election window each year." To ensure consistency between the two provisions and to provide clarity regarding a returning DA customer's annual election, BRTM proposes the following revision to OAR 860-038-0290(13):

> (13) A preferentially curtailable consumer that returns to the electric company's service without the required notice of return under the electric company's direct access program tariff shall be subject to potential curtailment for **as long as the customer elects preferential curtailment pursuant to section (6) of this rule, but in no event longer that the** ~~a~~ period equal to the remaining time for notice of return.

Further, comment was made at the Commission's open meeting on April 4, 2023 regarding potential practical implications of a DA customer switching its election on an annual basis, including (1) whether yearly election is too often and (2) how changing elections would interface with potential DA caps. Regarding the first concern, BRTM agrees with Staff that some flexibility is required to address changing circumstances. Accordingly, BRTM proposes that a DA customer be able to change their election during any election window occurring at least two years after their initial election or any subsequent election change thereafter. To effectuate this change, BRTM recommends the following language revision to proposed OAR 860-038-0290(6):

> (6) A consumer may change their curtailment election during **any** ~~**the**~~ annual election window ~~**each year**~~ **occurring at least two years after the customer's initial curtailment election or any subsequent change to the customer's curtailment election**.

Regarding the second concern, BRTM agrees that there are practical implications associated with changing elections and whether any room under any pertinent cap exists. Consistent with the comments above, BRTM recommends that these issues be addressed in the contested phase of this proceeding

5. The Commission should not impose a ridged time limit to return to direct access under proposed OAR 860-038-0290(15)(b).

Currently, the NOPR states that "Sections (13) and (14) of this rule do not limit a New Large Load Direct Access Program participant or long-term opt-out direct access consumer's right to return from default supply to direct access unless … [t]he consumer remains on default supply for longer than the time period necessary to select an ESS and return to direct access service. This time period will be determined by the Commission." This language would have the Commission establish a time limit within which any returning customer would have to obtain an alternative ESS. While it is helpful to have a general benchmark for evaluating a return to DA service, it is (1) unclear how the Commission is to make this determination and (2) unreasonable to apply a time limit without exception.

The purpose of this docket is, in part, to protect against risks associated with an unexpected return of a DA customer. The main risk referenced during the informal rulemaking phase of this proceeding has been potential cost shifts to cost-of-service customers. Accordingly, proposed OAR 860-038-0290(15)(b) should reference this risk in guiding the Commission's determination of a time period applicable to return to direct access.

Further, a DA customer's return to utility service is unexpected and hard to predict. The market dynamics at the time of a customer's return may be unpredictable and will necessarily influence the DA customer's desire and ability to return to the market. Prescribing a definitive timeline within which a returning DA customer must reenter the market, without exception, may lead to uneconomic consequences to the DA customer, the DA market, the utility, and/or cost-of-service customers. Thus, there should be an ability for a DA customer to seek a Commission

waiver of the timeline if the customer can demonstrate that returning to direct access is nevertheless appropriate under the circumstances.

To capture these concerns, BRTM recommends the following revision:

> (15) Sections (13) and (14) of this rule do not limit a New Large Load Direct Access Program participant or long-term opt-out direct access consumer's right to return from default supply to direct access unless … (b) [t]he consumer remains on default supply for longer than the time period necessary to select an ESS and return to direct access service. This time period will be determined by the Commission **based on the date prior to which an electric company would not reasonably be expected to incur costs that would otherwise be stranded as a result of the consumer's return from default supply to direct access**. **This time period may be waived by application of the direct access consumer if the consumer demonstrates that return from default supply to direct access is appropriate under the circumstances.**

6. OAR 860-038-0290 should include rules related to the treatment of transition charges.

The proposed rules in the NOPR do not include rules related to the treatment of transition charges. Transition charges are designed to protect against "the shifting of costs to pay for investments made by the utility before the customer opted out to those customers that do not opt out."[17] For example, PacifiCorp has a "five-year opt-out program that allows a qualified customer to go to direct access and pay fixed transition charges for the next five years."[18] Following the five years of transition charges, the DA customer is "no longer subject to transition adjustments--for so long as that customer remains a direct access customer (on the Pacific Power system)."[19]

Critical here is how to treat DA customers that are still within the five-year transition charge period and unexpectedly return. In this instance, it is appropriate to waive any applicable transition charges. During the period in which a returning DA customer again takes bundled

[17] *Calpine*, 298 Ore. App. 143 at 147.
[18] *In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-out*, Docket No. UE 267, Order No. 15-060, p. 2 (Feb. 24, 2015).
[19] *Id.*

service from its respective utility, there can be no stranded costs given that it is taking both energy and distribution services. Indeed, the point of this docket is an attempt to protect against increased costs as a result of a DA customer's return—as opposed to the stranding of costs as a result of their exit. During this period of return, the DA customer's remaining transition charges should be deferred until the DA customer decides to return to an ESS or waived entirely if the customer elects to remain a fully bundled customer of the utility. Therefore, BRTM recommends the following addition to proposed OAR 860-038-0290:

> **(16) Upon the return of a New Large Load Direct Access Program participant or long-term opt-out direct access customer, any applicable transition charges not yet charged must be deferred, and not charged, during the period of time the customer takes default supply service from the electric company until:**
>
> **(a) The customer returns to direct access, in which case any remaining transition charges must be charged to the direct access customer over a period equal to the remaining transition period at the time the customer returned to electric company service; or**
>
> **(b) The customer becomes a cost-of-service customer of the electric company, in which case any deferred transition charges will be waived entirely and no longer be applicable.**

D. Proposed OAR 860-038-0405(3)(c) should reference only those DA customers that an ESS serves.

Proposed OAR 860-038-0405(3)(c) states: "A load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers."[20] BRTM proposes to make the following revision:

> (c) A load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers **served by the ESS**.

This proposed change recognizes that an ESS in its report cannot aggregate for all Oregon Direct Access customers unless that single ESS serves all Direct Access customers in the state. The

[20] NOPR, p. 12 (proposed rule language for OAR 860-038-0405(3)(c)).

proposed revision provides more specificity to an ESS's reporting requirements, and BRTM respectfully requests that it be adopted.

II. Conclusion

BRTM appreciates the opportunity to comment on these important issues and looks forward to engaging with the Commission and other parties in this rulemaking process.

DATED this 25th day of April, 2023.

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ATTORNEYS FOR BRTM

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AMEND: 860-038-0005
RULE TITLE: Definitions for Direct Access Regulation
RULE SUMMARY: This rule adds a definition for "Preferential Curtailment," deletes unnecessary definitions, arranges the definitions alphabetically, and renumbers the rule provisions.
RULE TEXT:

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) "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.

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

(a) Energy efficiency audits and programs;

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

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

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

(5) "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.

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

(7) "Economic utility investment" means all Oregon allocated investments made by an electric company that offers direct access under ORS 757.600 to 757.667, including plants and equipment and contractual or other legal obligations, properly dedicated to generation or conservation, that were

prudent at the time the obligations were assumed but the full benefits of which are no longer available to consumers as a direct result of 757.600 to 757.667, absent transition credits. "Economic utility investment" does not include costs or expenses disallowed by the Commission in a prudence review or other proceeding, to the extent of such disallowance, and does not include fines or penalties authorized and imposed under state or federal law.

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

(9) "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.

(10) "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.

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

(12) "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.

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

(14) "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.

(15) "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.

(16) "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.

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

Renewable Certificates.

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

(19) "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.

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

(21) "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.

(22) "Non-bypassable Charges" are costs that are directed by the legislature to be recovered by all customers or charges that retail consumers served by electricity service suppliers otherwise may avoid by obtaining electric power through direct access that are determined by the Commission to be appropriate for recovery from all customers.

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

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

(a) Local governments;

(b) Electric companies;

(c) Residential consumers;

(d) Public or regional interest groups; and

(e) Small nonresidential consumers.

(25) “Preferential Curtailment” refers to the electric company's obligation to curtail eligible direct access consumers that return to the electric company service without providing the electric company with the full period of notice required by the electric company’s direct access program tariff.

(26) "Proprietary consumer information" means any information compiled by an electric company on a consumer in the normal course of providing electric service that makes possible the identification of any individual consumer by matching such information with the consumer's name, address, account number, type or classification of service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges,

billing records, or any other information that the consumer has expressly requested not be disclosed. Information that is redacted or organized in such a way as to make it impossible to identify the consumer to whom the information relates does not constitute proprietary consumer information.

(27) "Qualifying expenditures" means those expenditures for energy conservation measures that have a simple payback period of not less than one year and not more than 10 years and expenditures for the above-market costs of new renewable energy resources, provided that the Oregon Department of Energy may establish by rule a limit on the maximum above-market cost for renewable energy that is allowed as a credit.

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

(29) "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.

(30) "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.

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

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

terms of the electric company's tariff regarding public purpose credits.

(33) "Site" means:

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

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

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

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

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

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

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

(36) "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.

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

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

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

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

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

(42) “Uncommitted Supply” is generation reasonably available to the electric company in the market

or through the electric company's own resources. Uncommitted Supply excludes any generation needed to meet the electric company's firm load service obligations, anticipated near-term load obligations, contractual obligations, and federal reliability standards.

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

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

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756, ORS 757
STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 757.600 - 757.667

ADOPT: 860-038-0170
RULE TITLE: Non-bypassable Charges
RULE SUMMARY: This rule articulates criteria used in Commission determinations on whether a charge should not be able to be bypassed as a result of taking Direct Access service.
RULE TEXT:

(1) In determining whether a cost is appropriate for recovery as a non-bypassable charge, the Commission shall consider the following factors:

(a) whether the charge proposed to be non-bypassable is required by statute;

(b) whether the charge proposed to be non-bypassable is a cost identified in ORS 469A.465 or similar public policy goals related to reliability, equity, decarbonization, resiliency or other public interest for which retail consumers served by electricity service suppliers otherwise would not meaningfully contribute;

(c) whether or not the utility action associated with the charge proposed to be non-bypassable confers a demonstrable electric system benefit on some customers over others;

(d) whether designating the charge as non-bypassable is in the public interest;

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

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

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756, ORS 757
STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 757.600 - 757.667

ADOPT: 860-038-0290
RULE TITLE: Preferential Curtailment
RULE SUMMARY: This rule directs utilities to curtail returning customers on emergency default service in specific scenarios.
RULE TEXT:

(1) This rule becomes effective June 1, 2024.

(2) Except as provided in sections (4), (8), and (9) of this rule, each electric company must provide preferential curtailment of New Large Load Direct Access Program participants, as defined in OAR 860-038-0700(2)(d), and long-term opt-out direct access consumers.

(3) At the time a consumer makes its direct access election, New Large Load Direct Access Program participants and long-term opt-out direct access consumers must elect whether a given load will be preferentially curtailable or non-curtailable. A consumer that makes no such election will be deemed non-curtailable.

(4) An electric company may not preferentially curtail the load of a direct access consumer when:

(a) The direct access consumer, has elected to be non-curtailable during the election period;

(b) The direct access consumer's load is infeasible to curtail;

(c) The preferential curtailment of a direct access consumer would negatively affect cost-of-service consumers; or

(d) Uncommitted Supply is available as described in section (9) of this rule.

(5) Consumers already participating in a New Large Load Direct Access Program or long-term opt-out direct access service must make the election defined in section (3) of this rule during the first annual election window that takes place at least 12 months after the effective date of this rule.

(6) A consumer may change their curtailment election during any annual election window occurring at least two years after the customer's initial curtailment election or any subsequent change to the customer's curtailment election.

(7) The Commission may establish a cap on non-curtailable direct access load.

(8) Using a Commission approved methodology, an electric company may collect a reasonable charge from a direct access consumer to recover necessary costs for system upgrades that operationalize preferential curtailment of that consumer. Any given load that a consumer elects to be curtailable will be considered non-curtailable until the system upgrades required to curtail the load are installed, tested, and properly functioning.

(9) If a preferentially curtailable consumer returns to default supply without providing the required time for notice of return under the electric company's direct access program tariff, the electric

company must make best efforts to serve the consumer with Uncommitted Supply.

(10) The Commission will establish criteria the electric company may use to demonstrate that it sought to serve a preferentially curtailable consumer with Uncommitted Supply before curtailing that consumer.

(11) If a returning preferentially curtailable consumer is served with Uncommitted Supply, the consumer will be charged the greater of the incremental capacity and energy costs or the costs that would have been charged if the consumer was receiving electric service pursuant to the electric company's applicable cost-of-service rate schedule.

(12) If Uncommitted Supply is not available, the electric company may preferentially curtail returning nonresidential direct access consumers' load that has been elected to be curtailable.

(13) A preferentially curtailable consumer that returns to the electric company's service without the required notice of return under the electric company's direct access program tariff shall be subject to potential curtailment for as long as the customer elects preferential curtailment pursuant to section (6) of this rule, but in no event longer that the period equal to the remaining time for notice of return.

(14) If a non-curtailable consumer returns to the electric company's service without the required notice of return under an electric company's direct access program tariff, the electric company shall charge the non-curtailable consumer the greater of the incremental capacity and energy costs or costs that would have been charged if the consumer was receiving electric service pursuant to the electric company's applicable cost-of-service rate schedule.

(15) Sections (13) and (14) of this rule do not limit a New Large Load Direct Access Program participant or long-term opt-out direct access consumer's right to return from default supply to direct access unless:

(a) The consumer has provided a notice of return to the electric company's service, or;

(b) The consumer remains on default supply for longer than the time period necessary to select an ESS and return to direct access service. This time period will be determined by the Commission based on the date prior to which an electric company would not reasonably be expected to incur costs that would otherwise be stranded as a result of the consumer's return from default supply to direct access. This time period may be waived by application of the direct access consumer if the consumer demonstrates that return from default supply to direct access is appropriate under the circumstances.

(16) Upon the return of a New Large Load Direct Access Program participant or long-term opt-out direct access customer, any applicable transition charges not yet charged must be deferred, and not charged, during the period of time the customer takes default supply service from the electric company until:

(a) The customer returns to direct access, in which case any remaining transition charges must be charged to the direct access customer over a period equal to the remaining transition period at the time the customer returned to electric company service; or

(b) The customer becomes a cost-of-service customer of the electric company, in which case any deferred transition charges will be waived entirely and no longer be applicable.

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756, ORS 757
STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 757.600-757.667

AMEND: 860-038-0300
RULE TITLE: Electric Company and Electricity Service Suppliers Labeling Requirements
RULE SUMMARY: This rule change directs ESSs to disclose energy supply mix and the associated emissions annually.
RULE TEXT:

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

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

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

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

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

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

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

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

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

environmental impact information based on the unspecified market purchase mix. The electric company must report power source and environmental impact information for standard offer sales based on the unspecified market purchase mix.

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

(a) Coal;

(b) Hydroelectricity;

(c) Natural gas;

(d) Nuclear; and

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

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

(a) Carbon dioxide, measured in lbs./kWh of CO2 emissions;

(b) Sulfur dioxide, measured in lbs./kWh of SO2 emissions;

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

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

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

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

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

(11) By September 1, each electric company and each electricity service supplier making any claim

other than unspecified market purchase mix must file a reconciliation report for the prior calendar year on forms prescribed by the Commission. The report must provide a comparison of the power source mix and emissions of all of the seller's certificates, purchase or generation with the claimed power source mix and emissions of all of the seller's products and sales.

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

STATUTORY/OTHER AUTHORITY: ORS 183, 756, 757
STATUTES/OTHER IMPLEMENTED: ORS 756.040, 757.600 - 757.667

ADOPT: 860-038-0405
RULE TITLE: ESS Emissions Planning Report
RULE SUMMARY: This rule establishes the requirements for annual forward-looking ESS Emissions Planning Reports and DEQ emissions reports.
RULE TEXT:

(1) From June 1, 2024, through May 30, 2027, each ESS certified pursuant to ORS 757.649 that has sold electricity to retail electricity consumers in Oregon in the previous calendar year or has executed a contract to sell electricity to retail electricity consumers in Oregon within the following three calendar years are required to file a copy of the annual greenhouse gas emissions report submitted to the Oregon Department of Environmental Quality in accordance with Oregon Laws 2021, Chapter 508, Section 5(4)(a) within 10 days of filing with the Oregon Department of Environmental Quality.

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

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

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

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

(c) A load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers served by the ESS;

(d) An estimate of the annual greenhouse gas emissions associated with serving Oregon Direct Access customers, forecasted for the following three consecutive years;

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

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

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

(A) Development of non-emitting dispatchable resources;

(B) Demand response offerings;

(C) Energy efficiency offerings; and

(D) Onsite renewable generation.

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

(5) Commission staff and interested persons may file written comments on each ESS's Emissions Planning Report within 45 calendar days of the filing. The ESS may file a written response to any comments within 30 calendar days thereafter. After considering written comments, the Commission may decide to commence an investigation, begin a proceeding, or take other action as necessary to make a determination regarding Oregon Laws 2021, Chapter 508, Section 5 requirement for continual and reasonable progress toward compliance with the clean energy targets set forth in Oregon Laws 2021, Chapter 508, Section 3.

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

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

(8) Availability of Information:

(a) Information regarding an analysis of the $/MWh (levelized if under different pricing structure) that the customer will be charged for service related to compliance for each of the next 3 years, as required by section 3(f) of this rule will be available for review only by Qualified Statutory Parties, meaning any Commission Staff and any representatives of the Citizen's Utility Board, who executed a modified protective order.

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

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

emissions reporting methodology, as required in Section 3(e) of this rule;

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

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

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

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756, ORS 757
STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 757.600-757.667

AMEND: 860-038-0590
RULE TITLE: Transmission and Distribution Access
RULE SUMMARY: This rule is amended to provide a necessary exception from section (3) in the event that the preferential curtailment rules in OAR 860-038-0290 are applied and to make housekeeping changes.
RULE TEXT:

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

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

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

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

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

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

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

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

(B) Self-provision; or

(C) Purchases from a third party;

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

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

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

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

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

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

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

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

(4) If adherence to this rule requires FERC approval of tariff or contract provisions, the electric company must petition FERC for the approval of the tariff or contract provisions in a timely manner.

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756, ORS 757
STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 757.600 - 757.667

AMEND: 860-038-0740
RULE TITLE: New Large Load Program Enrollment and Rates
RULE SUMMARY: This rule is amended to become consistent with the rules regarding non-bypassable charges in OAR 860-038-0170.
RULE TEXT:

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

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

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

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

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

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

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

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

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

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

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

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

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

(5) A participant may be exempted from charges made under section (4) of this rule if the participant

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

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

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756, ORS 757
STATUTES/OTHER IMPLEMENTED: ORS 757.600 - 757.667, ORS 756.040

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