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AR 651: Division 38 Direct Access Regulation Straw Proposal

Parties to AR 651,

At the public meeting on July 12th, 2022, the Commission determined that certain issues in the AR 651 rulemaking required further detail and policy guidance. Staff has updated its proposed language for Non-bypassable Charges and confidentiality in ESS Emissions Reports, and added rule language on the operationalization of preferential curtailment and provider-of-last-resort responsibilities. Lastly, Staff has included policy positions regarding Direct Access program caps and encourages stakeholders to provide feedback in comments. Staff intends to bring the content in this proposal to the Commission at the October 4th public meeting and appreciates any engagement or feedback from parties. The topics that Staff addressed and the associated rule language are described below:

Non-bypassable Charges, Page 4:

Staff supports certain revisions proposed by NIPPC, CUB, the environmental NGOs, AWEC, and the Joint Utilities to the rule language regarding non-bypassable charges. The language provides clearer criteria to guide contested case determinations and puts clear boundaries around the arguments that can be made about non-bypassability but does not overly restrict consideration of fairness on a cost-by-cost basis.

Default Supply, Provider of Last Resort, Preferential Curtailment, Page 4-6:

Staff believes that preferential curtailment may be the best option to implement the IOU's POLR in many circumstances. Given the state of the energy industry and the difficulty IOUs will face implementing a reliable and just energy transition for their cost-of-service (COS) customers, Staff believes that it is reasonable to adopt policies that encourage Direct Access (DA) customers and Electric Service Suppliers (ESSs) to be responsible for their own reliability. Staff plans to recommend requirements for an ESS to demonstrate resource adequacy (RA) either through participation in a regional RA program or a statewide program in Docket No. UM 2143. With this framework in place, Staff believes that preferential curtailment better balances reliability and efficiency than relying on the IOU to acquire duplicate capacity resources in an increasingly tight market for non-emitting capacity. Staff notes that preferential curtailment would only be enacted when energy is not available on the market and when the utility does not have excess generation capacity. Market purchases or excess generation should be utilized in lieu of preferential curtailment when possible. Any system upgrades required to enable preferential curtailment should be paid for by the respective DA customer or through an agreement with the ESS.

Staff understands that there may be limitations to preferential curtailment relating to cost and system reliability. If it is determined that preferentially curtailing a DA customer is wholly infeasible or will impact system reliability for COS customers, it is reasonable to consider an exemption where the customer must contract with the utility for POLR capacity. To enable this, Staff proposes that the utility would plan capacity for that specific customer, while the customer pays a charge for the capacity investment plus any generation used to serve that customer upon returning in a default scenario. The formula to determine these charges will be determined in the contested case. Rules specifying this curtailment exemption are proposed in 860-038-0290. Specific criteria for exemptions based on a utility's system capabilities and costs can be established in the contested case.

Acknowledging the limitations above, Staff believes that utilities should have the capability to operationalize preferential curtailment given the curtailment requirements for qualifying facilities (QFs), the capabilities of demand response pilots like PGE's Dispatchable Standby Generation, and the deployment of distribution automation investments described in distribution system planning. Staff also sees preferential curtailment in POLR scenarios as consistent with the treatment of natural gas transport customers as outlined in Northwest Natural Gas Company's General Rules and Regulations, Rule 13. While Staff understands the multitude of operational differences between natural gas and electricity service, curtailment of natural gas customers demonstrates that this type of treatment is not unfounded.

Additionally, Staff finds that the issue of preferential curtailment also informs contested case decisions around DA program caps. Staff believes that, in the event caps are set, a regular recalculation could be required to address the changing risk from curtailment-exempt customers.

Please note that in OAR 860-038-0590 on page 7, Staff has included an exclusionary phrase to indicate that the requirements of Section 0590 do not apply in the instance of preferential curtailment. Staff believes this modification is required since the concept of knowingly curtailing one customer over another directly contradicts Section 0590's designation for non-discriminatory access to transmission and distribution for all retail customers.

Confidential Designations in ESS Emissions Planning Reports, Page 6-8:

Staff supports the additions addressing confidential information in the ESS Emissions Planning Reports. The language adds specificity on how parties can access certain categories of information and provides a transparent approach to information sharing via protective order.

Direct Access Program Caps:

Staff did not propose rule language on DA caps at this time based on the Commission's acknowledgment at the July 12th public meeting that significant distance exists between parties' positions and other topics have potential for further stakeholder engagement. However, addressing caps at this phase is important for guiding contested case determinations in the future. Staff has proposed its positions on what rule language could be included, with the intention that parties engage prior to moving to a formal rulemaking.

Staff proposes that the Commission may impose a cap if:

- An increase in DA load compromises system reliability.
- An increase in DA load shifts an unacceptable amount of cost to COS customers.
- An increase in DA load poses undesirable long term financial impacts to COS customers or the electric system.
- An increase in DA load poses other unmitigated risk to COS customers.

The specific amount of increase to DA load, level of risk, and amount of costs that trigger the criteria above can be determined in the contested case phase. Staff believes these guidelines establish how the Commission makes decisions on whether a cap is necessary.

Additionally, Staff reminds parties of the past policy positions on caps and invites feedback:

- To the extent that caps are implemented in a future contested case, Staff proposes that overall DA caps will be recalculated each year, or another regular interval, prior to the annual election window to determine availability under the cap. Caps would be updated to be responsive to the ongoing risks of the program.
- Petitions to exceed a cap will be examined through a 90-day process.
- Behind-the-meter (BTM) load growth can be accommodated provided all risks and cost shifts are addressed through transition charges or RA. A phased approach could address the rate of BTM growth by allowing only a certain percentage of BTM load growth each year.

Lastly, please note the remaining important dates for the informal rulemaking phase below:

September 15th: Deadline for filing written comments on Staff's straw proposal.

October 4th Public Meeting: Staff brings revised rule language and policy positions before the Commission. Request to move to a formal rulemaking.

Staff is not proposing a specific schedule for the contested phase at this time due to the difficulty of grouping and prioritizing issues prior to a Commission determination on the rulemaking. However, Staff is open to parties proposing aspects of the schedule and will engage in those discussions.

Thank you,

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Attachment A: Proposed Division 038 Rules

All additions to the rule language since Staff's previous proposal are in blue font. Staff has only included the sections in the Division 038 rules where new revisions and additions are proposed.

860-038-0170
Non-bypassable Charges

(1) "Non-bypassable Charges" ~~refers to costs that are directed by legislature to be recovered by all customers or determined by the Commission to be associated with implementing public policy goals related to reliability, equity, decarbonization, resiliency, or other public interests.~~

~~(2) The Commission will consider whether a charge meets some or all of the following when determining whether it is non-bypassable:~~ **are costs that are directed by the legislature to be recovered by all customers or charges that retail consumers served by electricity service suppliers otherwise may avoid by obtaining electric power through direct access that are determined by the Commission to be appropriate for recovery from all customers. In determining whether a cost is appropriate for recovery as a non-bypassable charge, the Commission shall consider the following factors:**

(a) **whether** it is required by statute

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

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

(d) **whether** it is in the public interest

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

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

860-038-0280
Default Supply

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

Commented [BM*P1]: Staff generally agrees with the definition proposed by NIPPC, CUB, the environmental NGOs, and AWEC with certain modifications made by the Joint Utilities. It aligns with statute but is not overly restrictive in how the Commission addresses cost allocations.

Commented [BM*P2]: Staff agrees with the Joint Utilities that adding "or" is appropriate as the legislature does not have to address every single cost allocation specifically.

Commented [BM*P3]: Staff agrees with the Joint Utilities that "factors" implies that the Commission can determine that a certain aspect is irrelevant in its decision. Staff believes this is important for Commission discretion when applying these rules.

Commented [BM*P4]: "Uneconomic Cost of Implementing a Public Policy Goal" means the difference between the cost of implementing the public policy goal and the regulated costs that are avoided through as a result of implementing the public policy goal."

Staff notes that the term "regulated cost" within the definition of "an uneconomic cost of implementing a public policy goal" is self-explanatory and plain language, and therefore does not require a definition.

Commented [BM*P5]: Staff agrees with moving this statement from the non-bypassable definition into the list of criteria. It enables the definition to be more similar to language used in statue yet allows the Commission to still factor in equity, decarbonization, public interest, etc. into a cost allocation decision.

Commented [BM*P6]: Staff has not included the Joint Utilities revision that ESSs/customers must contribute their "fair share". Staff believes that the full amount of a charge could be made non-bypassable based on other factors or consideration of the whole. Instead, Staff has specified that the costs to ESSs/customers are those that they would not otherwise "meaningfully" contribute to.

Commented [BM*P7]: Staff has not adopted the Joint Utilities' proposal to remove "in order to establish fair, just, and reasonable rates."

The utilities explain that the Commission could make a decision that establishes fair, just, and reasonable rates but causes cost shifting.

...

Commented [BM*P8]: Staff agrees with the Joint Utilities that specifying "all retail electricity customers" is redundant since customers served by IOUs will already be paying these costs. Staff has included the specificity so that this rule only refers to DA customers.

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

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

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

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

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

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

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

860-038-0290
Preferential Curtailment

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

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

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

(3) If an ESS is no longer providing service and market energy or excess generation is not available, the electric company may preferentially curtail returning nonresidential direct access consumers of that ESS.

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

Commented [BM*P9]: These customers will still be charged the emergency default supply rates if market purchases and/or the utility's excess generation can serve them. If there is not sufficient energy available on the market or excess utility generation, they can be curtailed instead.

Commented [BM*P10]: The methodology for determining these costs will be decided in the contested case phase.

(5) An electric company is exempt from providing preferential curtailment for non-residential direct access consumers if it is infeasible to do so or curtailment would negatively affect the electric system's reliability.

(a) Where an electric company is exempt from providing preferential curtailment, the electric company will plan for and acquire capacity to account for a direct access consumer's potential return to the electric company's service.

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

Commented [BM*P11]: Identifying what criteria determines whether curtailment is "infeasible" can be established in the contested case. Curtailment feasibility may encompass cost, risk, or engineering limitations.

Commented [BM*P12]: Specifying that these exempt customers should only pay the costs of the capacity and generation that serves them. They should not be subject to the additional percentage costs of emergency default supply service since they are already paying for planned capacity

860-038-0405
ESS Emissions Planning Report

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

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

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

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

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

(c) Load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers.

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

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

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

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

(i) Development of non-emitting dispatchable resources;

(ii) Demand response offerings;

(iii) Energy efficiency offerings; and

(iv) Onsite renewable generation.

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

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

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

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

(8) Availability of Information:

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

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

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

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

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

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

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

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

860-038-0590

Transmission and Distribution Access

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

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

(3) **Except as otherwise directed by OAR 860-038-0290**, each electric company shall provide nondiscriminatory access to transmission, distribution, and ancillary services, including transmission into import-limited areas and local generation resources within import-limited areas, to serve all retail consumers. An electric company shall not give preference or priority in transmission and distribution pricing, transmission and distribution access, or access to, pricing of, or provision of ancillary services and local generation resources, to itself or its affiliate relative to persons or entities requesting transmission or distribution access to serve direct access consumers. No preference or priority may be

given to, nor any different obligation assigned to, any consumer based solely on whether the consumer is purchasing service from an electric company or an ESS.

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

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

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

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

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

(B) Self-provision; or

(C) Purchases from a third party;

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

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

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

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

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

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

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

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

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