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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I. INTRODUCTION & SUMMARY

Brookfield Renewable Trading and Marketing LP ("BRTM") hereby submits the following comments on policies or revisions addressing a workable provider of last resort ("POLR") solution pursuant to the Schedule Update issued October 14, 2022. In the Schedule Update, Oregon Public Utility Commission ("OPUC" or "Commission") staff ("Staff") outlined a schedule where parties continue informal discussions on POLR-related issues in order to potentially reach a consensus proposal and reserve for the formal contested phase of the proceeding issues related to Direct Access ("DA") caps and other more contentious issues.

With respect to POLR requirements, Staff and stakeholders have discussed concerns related to (1) electric service suppliers ("ESS") potentially leaning on investor-owned utilities ("IOU") and (2) DA customers unexpectedly returning their entire load to an IOU and associated potential cost shifts. As discussed in detail below, several protections are in place to limit concerns regarding potential ESS leaning and any related cost shifts. These protections include: the ability of IOUs, acting as transmission providers, to charge and recover costs related to the provision of Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT") prescribed ancillary services, including operating reserves and imbalance energy; state and regional resource adequacy requirements, including, to the extent that an ESS participates in the Western Resource Adequacy Program ("WRAP"), the specific ability of that ESS to rely on capacity available through the WRAP prior to relying on assistance from its host utility; and the ability of an IOU to utilize and charge a returning customer for emergency service, potentially for a longer and appropriate amount of time prior to returning to bundled service. Regarding issues related to a DA customer returning their entire load to an IOU, BRTM maintains that prospective capacity backstop charges are inappropriate and uncompetitive. ESSs have reliably served their loads in Oregon for over two decades. Absent specific concern with a specific ESS, prospective capacity backstop charges must be avoided. However, PacifiCorp's ("PAC") proposal submitted earlier in this docket and discussed in the stakeholder workshop on November 2, 2022 warrants further discussion. BRTM's comments below raise several concerns with PAC's proposal for Commission Staff and stakeholder consideration.

II. COMMENTS

a. Capacity backstop charges should not be assessed to address the unlikely event of an ESS leaning on an IOU.

There is no justification sufficient to warrant the payment of prospective capacity backstop charges to address the unlikely event that an ESS leans on an IOU. This is particularly true because current mechanisms protect against the occurrence of any adverse impact on reliability and appropriately compensate the utility for any service provided. These protections become even more prevalent to the extent an ESS participates in the WRAP. Further, other less burdensome alternatives exist to prospectively evaluate and address cost-shift concerns; namely, the resource adequacy requirements being considered in UM 2143. Absent a specific concern with a particular

ESS, prospective capacity charges would only be duplicative and chill the economic viability of DA.

i. Portland General Electric's ("PGE") and PAC's OATT already provide protections that address the costs of short-term services.

ESSs receive Network Integration Transmission Service ("NITS") from IOUs. To obtain NITS service, ESSs must demonstrate that their resources are Network Resources. By contracting for power supply from an ESS, DA customers, and not an IOU, take on the risk that their ESS will not provide them the power necessary for their individual operations. This risk includes facing the consequences of non-delivery through potentially extraordinarily high market prices for energy pursuant to the terms and conditions of Schedule 4 Energy Imbalance Service under PGE or PAC's OATT when electric supplies are tight. DA customers manage this pricing risk through the terms and conditions of their contract with their respective ESS, while ESSs manage the risk passed on to them by their contracts with DA customers, including maintaining sufficient supply and demand resources through ownership, lease, or contract to meet the requirements of their contracts with their DA customers. To meet those requirements, ESSs often carry extra resources, essentially, the equivalent of planning reserves, which, under a state or regional RA program, will be thoroughly evaluated.

As Balancing Authorities, PAC and PGE are required to balance all loads and supply in their control areas on an hourly and sub-hourly basis. PAC and PGE recover the portion of the cost of balancing their systems that they incur on behalf of their bundled retail customers through Oregon-jurisdictional retail electric supply rates applicable to bundled retail customers. On the other hand, PAC and PGE recover the portion of the cost for balancing their systems that they incur on behalf of wholesale customers and DA customers through the ancillary service charges applicable to those customers under PAC's and PGE's respective OATTs.[1] These include both hourly and sub-hourly balancing capacity charges (*i.e.*, regulation, spinning operating reserve, and supplemental operating reserve charges) through PGE and PAC OATT Schedules 3, 5, and 6 and hourly and sub-hourly energy (*i.e.*, energy imbalance charges) through PGE and PAC OATT Schedule 4.

Schedule 3 of PGE's and PAC's OATT provide for "Regulation and Frequency Response Service," which "corrects for instantaneous variations between the customer's resources and load, even if over an hour these variations even out and require no net energy to be supplied."[2] ESSs that serve load in PGE's and PAC's balancing authorities "must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation."[3] If purchasing this service, PGE requires that ESSs pay for an amount of reserved *capacity* equal to 1.3% of the transmission customer's network load.[4] PAC's Schedule 3 charges are separated into a load component and a generator component, both of which are charged on a \$/kW-month or \$/kW-year basis.[5]

Schedule 5 is purposed to provide "Spinning Reserve Service," which is a capacity service "provided by generating units that are on-line and loaded at less than maximum output. [Spinning reserve is] available to serve load immediately in an unexpected contingency, such as an unplanned

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[1] Or. Admin R. § 860-038-0340(4) ("An electric company must provide ancillary services to facilitate direct access that are comparable to the services it provides for its own retail electricity consumers.").

[2] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 F.E.R.C. P61,080 (1996) (hereinafter "FERC Order 888").

[3] PGE OATT, Schedule 3 (effective Jan. 1, 2022); *see also* PAC OATT, Schedule 3 (effective Jan. 1, 2021) (stating that transmission customers "must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.").

[4] PGE OATT, Schedule 3 (effective Jan. 1, 2022).

[5] PAC OATT, Schedule 3 (effective Jan. 1, 2021).

outage of a generating unit."[6] Like Schedule 3, ESSs must purchase this service from PGE or PAC, provide it themselves, or utilize a third-party to provide the service. Under PGE's OATT, ESSs must purchase or provide themselves or through a third party reserved *capacity* equal to the sum of (1) 1.5 percent of the ESS's network load plus (2) 1.5 percent of the capacity of generating resources (including Network Resources mentioned above) identified by the ESS as a "source" for purposes of transmission scheduling.[7] Similar to PGE assessing spinning reserve capacity charges based on both load and generation, PAC imposes a charge sufficient to maintain spinning reserves in the amount of 1.5 percent of the ESSs "hourly integrated load" and another charge to maintain spinning reserves of 1.5 percent of "actual hourly generation" delivered by the ESS to PAC.[8]

Schedule 6, which provides for "Supplemental Reserve Service,":

> is also generating capacity that can be used to respond to contingency situations. Supplemental reserve, however, is not available instantaneously, but rather within a short period (usually ten minutes). Supplemental operating reserve is provided by generating units that are on-line but unloaded, by quick-start generation, and by customer-interrupted load, i.e., curtailing load by negotiated agreement with a customer to correct an imbalance between generation and load rather than increasing generation output.[9]

ESSs must purchase or make alternative arrangements to obtain this service. Under both PGE's and PAC's OATTs, the requirement to purchase or obtain a total of 3 percent (*i.e.*, 1.5 percent associated with network load and 1.5 percent related to generation) of operating reserve capacity is the same as in their respective Schedule 5.[10]

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[6] FERC Order 888, p. 214; *see also* PGE OATT, Schedule 5 (effective Jan. 1, 2022) ("Spinning Reserve Service is needed to serve load immediately in the event of a system contingency."); PAC OATT, Schedule 5 (effective Jan. 1, 2021) ("Spinning Reserve Service is needed to serve load in the BAA.").
[7] PGE OATT, Schedule 5 (effective Jan. 1, 2022).
[8] PAC OATT, Schedule 5 (effective Jan. 1, 2021).
[9] FERC Order 888, pp. 214-15; *see also* PGE OATT, Schedule 6 (effective Jan. 1, 2022) ("Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time."); PAC OATT, Schedule 6 (effective Jan. 1, 2021) ("Supplemental Reserve Service is needed to serve load in the BAA.").
[10] PGE OATT, Schedule 6 (effective Jan. 1, 2022); PAC OATT, Schedule 6 (effective Jan. 1, 2021).

Through Schedule 4, the "Energy Imbalance Service" provided "makes up for any net mismatch over an hour between the scheduled delivery of energy and the actual load that the energy serves in the control area."[11] Depending on the deviation of energy provided by the ESS, PGE's Schedule 4 imposes as much as a 25% penalty on top of the market price.[12] PGE's energy charges are based on the hourly Mid-Columbia Price Index published by Powerdex.[13] PAC's energy charges are based on the applicable load aggregation point ("LAP") price where the load is located.[14] The price per MWh for imbalance energy from PAC or PGE can be potentially extremely expensive at times of peak or net peak electric demand on the system, which does not take into consideration the potential for penalties to be assessed for any imbalances as well. As a result, high market prices for imbalance service send appropriate price signals to DA customers and ESSs and incentivize them to ensure they are resource adequate in order to balance their load. Capacity costs will be implicitly reflected in imbalance energy charges via high market prices, penalties, or scarcity pricing at times of greatest demand on PGE's or PAC's systems.

Considering all of these services that ESSs already purchase from PGE or PAC or obtain themselves, hourly leaning from both a capacity and energy perspective are fully considered and accounted for through OATT ancillary services. PGE and PAC are either compensated for these services or are excused from providing them because the ESS has made alternative arrangements for the same. Further prospective capacity backstop charges are inappropriate and duplicative.

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[11] FERC Order 888, p. 213; *see also* PGE OATT, Schedule 4 (effective July 1, 2014) ("Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour."); PAC OATT, Schedule 4 (effective Dec. 1, 2014) ("Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour (plus real power losses).").
[12] *Id.*
[13] PGE OATT, Schedule 4 (effective July 1, 2014).
[14] PAC OATT, Schedule 4 (effective Dec. 1, 2014).

ii. Imposing additional capacity backstop charges would chill participation in the WRAP.

While the WRAP is not a capacity market, the WRAP as contemplated will bind participants to make excess capacity available to other participants in the event that a participant becomes capacity deficient in any operating day. In other words, the WRAP is envisioned as a planning reserve sharing and mutual assistance pool. To ignore this core benefit of the WRAP and require ESSs to pay capacity backstop charges to IOUs would eliminate any incentive for ESSs to participate in the WRAP. Put differently, if an ESS is required to pay for capacity backstop service from an IOU, there is no incremental capacity sharing benefit from participation in the WRAP. WRAP provides participants with capacity insurance; further capacity insurance through prospective capacity backstop charges is unnecessary.

iii. State and/or regional resource adequacy requirements will ensure that ESSs and DA customers are resource adequate and will protect IOUs from cost shifts.

The benefits provided by and insights from resource adequacy requirements being considered in UM 2143 will provide the Commission and IOUs with assurances that ESS and DA customers are resource adequate and that capacity is available to serve those customers. In developing a long-term RA solution, the Commission and stakeholders will have the data to evaluate and address risks. Indeed, in Staff's report dated March 24, 2022, Staff stated that "compliance filings will keep the Commission apprised of the RA picture and allow for action if required on an individual LRE basis."[15] Developing and implementing a resource adequacy framework is the appropriate first step, and BRTM recommends that the Commission not impose prospective capacity backstop charges without first implementing resource adequacy forward

[15] Investigation into Resource Adequacy in the State – Staff Report, Docket No. UM 2143, p. 8 (Mar. 24, 2022).

showings. Resource adequacy requirements, and the related showings, are the appropriate forum to raise specific concerns with ESS resource adequacy and develop plans to remedy Commission-identified issues.

iv. Capacity backstop charges should be avoided unless specific concern arises with regard to a specific ESS.

Finally, while there are growing concerns regarding capacity constraints in the western region, ESSs have been able to serve their customers in Oregon for decades. Absent specific concern of a particular ESS's inability to serve their customers, capacity backstop charges should be avoided. Staff's March 24, 2022 report in UM 2143 states that Staff's "analysis did not point to any specific shortfall issues with any of the ESSs."[16] Should specific concerns arise, those should be captured in the review of applicable regional and/or state RA filings, and any deficiencies could be cured or addressed through the application of penalties assessed to deficient load responsible entities. Further charges (and charges absent specific concern) shift costs unnecessarily and erode the commercial viability of DA in the state. Specifically, Oregon law requires that the Commission "develop[] policies to eliminate barriers to the development of a competitive retail market structure."[17] Imposing capacity backstop charges such that DA customers would have to pay for capacity from an IOU *at the same time* as they pay for capacity from their ESS would be a policy that creates barriers to a competitive retail market structure. Put another way, having to pay twice for the same product erodes any incentive for electric customers in Oregon to enter the competitive electric market, especially when there exists no concern regarding a specific ESS's ability to serve its contracted load.

[16] *Id.*
[17] Or. Rev. Stat. § 757.646(1).

Because (1) ESSs purchase or otherwise obtain energy and capacity services from balancing authorities through their respective OATTs, (2) the WRAP is expected to include a capacity sharing benefit, (3) the Commission is contemplating state-specific resource adequacy forward showings, and (4) no specific concerns exist with regard to any ESS's ability to reliably serve its load, prospective capacity backstop charges should not be imposed.

b. Capacity backstop charges are inappropriate to protect against the speculative assertion that DA customers will return unexpectedly to utility service.

Similar to there being no justification to impose prospective capacity backstop charges to protect against an ESS relying on an IOU to meet its short-term capacity requirements, there is no demonstrable need to assess prospective capacity charges to protect against the unlikely and unexpected return of a DA customer to utility service. The stakeholder discussions to date have been less than clear as to the specific factual pattern that would lead to a DA customer's unexpected return such that prospective capacity backstop charges should be imposed. However, whether the fact pattern involves the ESS unexpectedly dropping the DA customer and leaving the state or the DA customer unexpectedly determining that DA is no longer for them, capacity backstop charges are not warranted in either speculative scenario.

i. There is no evidence to substantiate fears that ESSs will abandon their Oregon customers.

There has been no evidence presented to support a conclusion that an ESS certified by the Commission is at risk of being unable to serve its DA customers. At the November 2, 2022, stakeholder workshop, there was discussion regarding ESSs going bankrupt and leaving the DA market in Oregon unexpectedly, thereby stranding their DA customers. This unlikely event cannot justify imposition of prospective capacity backstop charges.

The Commission's ESS certification process includes evaluation of violations of consumer protection laws; audited financial statements; ESS balance sheets, income statements, and cash flows; creditworthiness; and technical competence in energy procurement and delivery, information systems, billing & collection, and safety & engineering.[18] PAC's and PGE's rules further require ESSs in their balancing authority to establish and maintain extensive minimum credit rating requirements.[19] These extensive licensing requirements already demonstrate that ESSs in Oregon are viable, stable, and sophisticated entities dedicated to providing competitive electric service to their customers. That the Commission and IOUs have gatekeeping protections in place to ensure only viable electric suppliers are granted the privilege of providing DA in Oregon offers the protections from the speculative concern that an ESS will outright abandon its business in the state. This is particularly the case where, as here, no stakeholder has demonstrated specific concern with a specific ESS's ability to reliably serve their customers in the long term. BRTM also notes that both ESSs and their customers enter into sophisticated contracts with detailed notice, credit, and damages provisions that mitigate the likelihood of any sudden or unexpected return to IOU service. In other words, the contracts between an ESS and its customer typically provide for a long glide path to termination of the contract; a glide path that would enable any DA customer to seek and retain competitive service from another ESS prior to suddenly or unexpectedly returning to utility service.

Additionally, the ancillary services purchased by ESS, WRAP capacity sharing pool, and resource adequacy forward showings all further mitigate the speculative risk that an ESS will breach their agreements with DA customers and leave Oregon.

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[18] Or. Admin. R. 860-038-0400(5).
[19] PAC Tariff, Rule 21, Section XIII; PGE Tariff, Rule K, Section 2.

ii. The possibility that a DA customer may choose to return to bundled service does not justify assessing capacity backstop charges.

If a DA customer chose to leave the competitive electric market and return to bundled service, that choice would most likely be driven by price (the extent of direct market cost exposure) and would most likely not be sudden. First, the IOUs have return-to-service notice provisions in place to ensure that they can begin to plan for that customer's return.[20] Second, as noted above, ESS and their customers have detailed contracts in place with extensive notice provisions. Third, and once again as detailed above, any customer is likely to seek out alternative competitive suppliers prior to returning to utility service. Therefore, imposing default capacity on all DA customers on the chance that they may ultimately, and after much process and consideration, return to utility service would stifle retail competition and effectively block DA customers from access to competitive alternatives to IOU service.

Therefore, the concern that DA customers will return to utility service without sufficient notice is unsubstantiated, and imposing prospective capacity backstop charges is inappropriate and anticompetitive.

c. While PAC's proposal warrants further discussion, several aspects of the proposal must be refined.

BRTM appreciates PAC's attempt to reach a compromise approach to capacity concerns as detailed in its proposal filed in this docket on November 2, 2022. It appears that through PAC's proposal and stakeholder discussions during the stakeholder conference on November 2, 2022, PAC also does not envision prospective capacity backstop charges for DA customers. Rather, BRTM understands PAC's proposal as follows:

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[20] *See e.g.*, PAC Tariff, Schedule 298, p. 3 (four-year's notice); PAC Tariff, Schedule 296, p. 1 (four-year's notice); PGE Tariff, Schedule 689-4 (three-year's notice).

- Returning load that is over 25 MW and can be curtailed within 10 minutes or less would be exempt from paying any capacity surcharge;
- Returning load that either is less than 25 MW or cannot be curtailed within 10 minutes would be subject to a capacity surcharge to recover incremental capacity costs;
- All returning customers would be assessed energy costs in the amount of the greater of the incremental cost to serve or the retail energy costs;
- The energy charge and capacity charge, if applicable, would be assessed for four years;
- If a DA customer returns and the IOU begins to plan for the returning customer's load, the customer cannot return to direct access for some, to be determined, period of time; and
- DA customers that cannot be curtailed would be subject to caps.

While BRTM believes that PAC's proposal warrants further discussion, there are several aspects of PAC's proposal that must be refined.

i. PAC's proposed preferential curtailment limits are too restrictive.

BRTM agrees with PAC that those customers who can be preferentially curtailed should not be assessed any capacity charges upon return and should not be subject to any caps. However, the thresholds PAC proposes are too restrictive. Particularly, the 25 MW load minimum to be eligible for preferential curtailment is too high. At the November 2, 2022, workshop, PAC expressed that a 25 MW minimum was necessary to meaningfully move the needle in a reliability event. However, the entire purpose of implementing preferential curtailment is to ensure that the DA customer is not causing any reliability issues on the IOU's system. If that DA customer can be curtailed (regardless of load size), that purpose is accomplished by quickly removing that *load* from the system and obviating the need for the utility to either plan for or procure, on either a short- or long-term basis, the *capacity* to serve that customer's load. Creating a minimum curtailable threshold is unnecessary and creates an arbitrary threshold that is not tied to a basis in reliable system operation. Any "demand response" moves the needle when addressing a reliability event. While a utility may want to establish a minimum threshold, driven by a number of cost, operational, market and other factors when considering the acquisition of power and capacity in the market to satisfy its planning or forward-procurement requirements, there is no need to establish minimum requirements for resources that will be available in the real-time operating timeframe to address a reliability event.

Similarly, PAC's proposed limit on preferential curtailment to only those who can respond within 10 minutes is too restrictive. Interruptible service schedules provide a useful guide. While voluntary interruptible service and mandatory curtailment are different, interruptible service is often used to address emergency reliability issues. Under PAC's Schedule 218, participants must respond within 30 minutes. PGE's Load Reduction Program in Schedule 88 is specifically defined for usage in emergency curtailment situations and also requires a 30-minute response time. Accordingly, if a returning customer is able to be preferentially curtailed (contractually or automatically) within 30 minutes, the returning customer should be able to enroll in preferential curtailment and avoid additional capacity charges.

ii. Imposing incremental capacity costs is not a one-size-fits-all approach.

BRTM recognizes and agrees that cost-of-service customers should not subsidize a DA customer that returns to utility service without proper notice. However, the calculous of imposing a fair, incremental capacity cost is not easily determined. First, and as discussed during the

November 2, 2022, stakeholder conference, existing customers that elect to take DA service pay transition charges over a 5-year period. During this period, DA customers are still compensating the IOU for the capacity the IOU procured to serve the DA customer. Simply because the customer elected to take DA service does not mean that the capacity the IOU used to serve the now-DA customer's load has evaporated. Accordingly, to the extent the DA customer is still paying the IOU transition fees, capacity backstop charges should not be assessed regardless of whether the returning DA customer can be preferentially curtailed.

Second, if a capacity surcharge is imposed, it is important to limit any capacity charges directly assigned to a returning DA customer to only those that are *incremental*. While incremental is included in PAC's proposal, it is important to consider that a returning DA customer that is placed on standard offer service will be paying capacity (and energy) costs through the applicable tariff. This increase in revenue must be considered. In fact, it is not hard to imagine a scenario in which a returning DA customer provides a significant benefit to cost-of-service customers if there is excess generation on the IOU's system. For example, a large load could exit the utility's system or close their business in Oregon around the same time as a DA customer unexpectedly returns. In this instance, the IOU would be in the same position and utility revenues (and resulting cost of service rates) would be unimpacted. The additional revenues and billing determinants from the returning DA customer would also help to share the IOU's overhead and operational costs across more customers and would provide additional compensation to support the reserves the IOU is already carrying to serve its customers. Thus, whether a utility is actually incurring incremental costs above the incremental revenues the utility would receive from a returning DA customer is a fact-specific question.

Because each DA customer is different and because it is pure speculation if and how many DA customers may return to utility service, BRTM recommends not setting a capacity charge for returning, non-curtailable customers in this proceeding. However, BRTM would be amenable to Staff drafting a rule that permits IOUs to file an application with the Commission to propose assessing an incremental capacity charge to a returning customer based on a fact-specific assessment of that customer's return to service. This framework would permit the DA customer to intervene and present argument. If the Commission determined that prudent incremental capacity costs were or will be incurred, the Commission could order that those costs be directly assigned for a reasonable time period, but in no event longer than the IOU's notice period for the return of a fully opted out DA customer.

iii. Energy costs assessed to a returning DA customer should be limited to the incremental costs to serve the customer.

PAC's proposal includes a recommendation that the DA customer pay energy costs in the amount of the greater of the incremental cost to serve and the retail market price. BRTM opposes this framework and recommends that emergency default service be extended to 30 days and, if a returning customer transitions to standard offer service after those 30 days, any energy cost assessments be limited to the incremental cost to serve the returning DA customer. Building in a longer buffer to emergency default service provides compensation to the IOU for the actual energy provided to the returning customer (including capacity costs through scarcity pricing in constrained market events); insolates cost-of-service customers from cost-shifts; and provides the returning customer with the flexibility to return to DA service, alleviating pressure for IOUs to engage in long-term planning of returning customer load. In the unlikely event that a DA customer returns to utility service and elects to take standard offer service after the emergency default period, imposing an energy cost greater than the incremental cost to serve the DA customer results in a potential windfall to the utility and a penalty to the returning customer. It also may discourage customers from returning to bundled service even when such a return could be beneficial to the system and other customers. Moreover, such a windfall or penalty is not what this docket is intended to accomplish. Any costs imposed on a returning DA customer should be limited to only collect the amount necessary to avoid potential cost shifts to bundled service customers. The incremental cost to serve the DA customer accomplishes that goal.

Further, though not explicit in PAC's proposal, PAC suggests that an incremental cost of energy from a DA customer's return includes potential foregone revenues from higher market prices. BRTM strongly opposes defining incremental to include foregone revenues from excess generation. The purpose of this docket is to protect against the speculative return of a DA customer without notice such that the IOU may be in a capacity constrained position. As stated above, any costs imposed should be limited to those that eliminate cost shifts to bundled customers.

Similar to the above, BRTM recommends that the Commission not set an incremental energy cost in this proceeding. In fact, assessing an incremental energy cost to returning DA customers is already in IOU tariffs. Specifically, PGE's Schedule 689 states:

> Except when disenrolled for failure to meet the threshold load standard established in this schedule, Customers must provide not less than three years notice to terminate service under this schedule. *If a Customer's return to cost-of-service increases rates for existing cost-of-service Customers by more than 0.5%, the Customer returning to cost-of-service will be subject to the forward looking rate adder, hereafter referred to as the "Energy Supply Return Charge"* noted below, *for three years beginning from the date of notice to return to cost-of-service*.

PAC's Schedule 293 is similar, stating:

> If a New Large Load Direct Access Program Consumer's switch to Standard Offer or Cost-Based Service will increase rates for existing cost-of-service Consumers by more than 0.5%, New Large Load Direct Access Program Consumers electing to

> switch to Standard Offer Service or Cost-Based Service will be subject to the forward-looking rate adder below for four years beginning from the date of the notice to return to Company Supply Service:

For both tariffs, the energy charge is set to 0.000 cents/kilowatt-hour ("kWh"). While set to zero, the tariff presents an opportunity for PAC or PGE to file an application with the Commission to change the rate if necessary upon return of a DA customer and the existence of incremental energy costs. Like the necessary procedure associated with proposed incremental capacity charges, the DA customer should be afforded an opportunity to intervene and present argument.

iv. Incremental energy and capacity costs should not automatically collect for four years.

As discussed above, it is unknown whether any DA customers will return unexpectedly, how many DA customers will return, and what capacity and energy position the IOU will be in when there is an unexpected return. Drafting a blanket rule that requires incremental capacity and energy costs to be assessed over four years fails to recognize the unique circumstances of any potential and unlikely return. Accordingly, the length of incremental capacity and energy payments should be determined by the Commission in the proceeding(s) IOUs initiate to recover incremental costs. Both the IOU and the DA customer can present argument for the Commission to resolve in a fair and holistic manner.

v. The rules should not impose limits on a returning customer's ability to obtain competitive electric service.

BRTM does not support a lock out, precluding a returning customer from obtaining competitive electric service simply because the IOU begins to plan for their load. The purpose of transition charges is to compensate for assets the DA customer strands following their exit from the utilities system. If the returning customer does not strand costs that negatively impact cost of service customers through additional transition charges, if necessary, the returning customer should be able to obtain competitive electric service. Imposing a lock out would create an actual barrier to the development of a competitive market in violation of Oregon law.[21] Therefore, BRTM recommends not precluding a returning customer from obtaining competitive electric service.

vi. Caps should not be addressed in this rulemaking.

Stakeholders and Staff have proceeded throughout this rulemaking with the understanding that caps would be addressed in the contested phase of this proceeding. The parties commented on and Staff proposed factors for the Commission to consider on whether to impose caps.[22] Whether caps should be imposed and to what load caps should apply are properly reserved for the contested phase of this proceeding. Accordingly, while BRTM continues to strongly oppose caps, these issues should not be addressed here.

III. Conclusion

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

[21] Or. Rev. Stat. § 757.646(1).
[22] Staff Report, Docket No. AR 651, pp. 8-9 (Sep. 26, 2022).

DATED this 18th day of November, 2022.

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