UE 358 / PGE / 200
Sims – Tinker

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 358

New Load Direct Access

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Brett Sims
Jay Tinker

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I. Introduction

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Brett Sims. I am the Senior Director of Strategy Integration & Commercial Initiatives for PGE.

My name is Jay Tinker. I am the Director of Regulatory Policy & Affairs for PGE.

Our qualifications were previously provided in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the Reply Testimony of the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), Calpine Solutions (Calpine), and the Oregon Citizens' Utility Board (CUB) filed regarding PGE's New Load Direct Access (NLDA) investigation into Schedule 689.

Q. How is your testimony organized?

A. We first discuss the parties' issues in our introduction and provide the context for where parties aligned in their arguments, then we discuss each contested issue by topic in the remaining sections of our testimony.

Q. Within parties' testimonies, are there recommendations, broadly supported in testimony, with which you generally agree?

A. Yes. Staff, AWEC and Calpine all support an additional investigation to consider changes to direct-access policy and the appropriateness of recovering capacity costs from both NLDA and Long-Term Direct Access (LTDA) customers. CUB supports broad changes to direct access policy necessary to ensure cost-of-service (COS) customers cease subsidizing direct access customers. Provided that PGE's NLDA program does not commence until the completion of any investigation opened, PGE agrees that an additional investigation on direct access policy for both NLDA and LTDA customers is warranted.

Q. What do parties propose for the intent and scope of such an investigation?

A. For PUC Staff, the intent of the investigation would be to investigate capacity resource or reliability/resource adequacy implications of the direct access programs, including PGE's proposed reliability charges, the Resource Adequacy charge (RAD) and the Resource Intermittency Charge (RIC)[1]. Calpine Solutions offers that it does not object to a separate investigation of resource adequacy and capacity provided on behalf of NLDA customers[2]. AWEC also notes that it would support an investigation into the RIC and RAD as well as into the planning and reliability issues raised by direct access loads. With regards to the RIC and RAD, AWEC points parties to its recently filed petition for an investigation into direct access, docketed as UM 2024[3].

Q. Does PGE support the identified scope for an investigation?

A. Yes. Again, PGE's agreement is contingent on the NLDA program being held in abeyance pending the outcome of the investigation. For this reason, PGE does not support AWEC's proposal that UM 2024 be the docket in which these issues are investigated. That would be premature, given the pendency of this current investigation.

Q. Why is it important that PGE's Schedule 689 not go into effect pending an investigation of direct access impact on resource adequacy, including the need to plan for the long term direct access loads, and PGE's RIC and RAD charges?

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[1] Staff/100, Gibbens/11.
[2] Calpine Solutions/100, Higgins/4.
[3] AWEC/100, Mullins/2. Also see AWEC's Petition for Investigation Into Long-Term Direct Access Programs. https://edocs.puc.state.or.us/efdocs/HAA/haa143134.pdf.

A. PGE's concerns are two-fold: 1) allowing NLDA to go into effect without changes to capacity procurement exacerbates the current resource adequacy issues, undermining the integrity of the power system, and 2) impact on customer decision making. If Schedule 689 were to go into effect without the RIC and RAD charges and with uncertainty about PUC approval of the charges and the amount of the charges, customers would be making decisions about direct access participation without knowing all the applicable terms and conditions. If the result of UE 358 were to have Schedule 689 go into effect without the RIC and RAD charges, and then the later investigation results in the Commission's approval of the charges, then fairness would demand that those charges should be borne prospectively by all customers who take service on Schedule 689, including those who started 689 service before such charges were approved. If that were to occur, it is foreseeable that customers would appeal to the Commission, claiming that they did not know of the Commission's investigation and proposed charges, and plead that the charges not apply to them as the charges significantly impact the economics of their direct access decision.

Q. Staff raises the importance of considering NLDA and LTDA together as both programs offer customers a long term opt out from PGE supply. Does PGE support extending the scope of such an investigation to include LTDA?

A. Yes. PGE recognizes that the Commission may find symmetrical resource adequacy concerns when evaluating LTDA and NLDA policy. An issue for PGE, is that the company (as well as Calpine Solutions and OPUC Staff) have agreed through stipulation not to propose changes to its LTDA program through program year 2021[4]. PGE supports an investigation to consider proposed changes to LTDA policy, to take effect in 2022.

Q. Should the Commission support a broader investigation into direct access and resource adequacy policy, what should be done with PGE's advice filing for Schedule 689, NLDA program implementation?

A. If the Commission prefers to address the undue shifting of costs and risks from all direct access customers to COS customers, then it should further extend the suspension period for PGE's advice filing and return to it following the conclusion of that investigation. This is Staff's primary recommendation which PGE supports.

Q. **Should the Commission prefer to expedite PGE's NLDA program implementation, can the Commission adopt the application as proposed?**

A. Yes. We disagree with Staff, AWEC, and Calpine's claim that PGE's Schedule 689 charges are discriminatory, and that the Commission should not approve reliability-related capacity charges for NLDA customers without simultaneously changing LTDA tariffs. As discussed later in our testimony, the idea of a NLDA program resulted from the Commission's findings that NLDA customers are a distinct class of customers.[5] These customers, by virtue of being new and unplanned for, carry immediate reliability concerns. They are unlike LTDA customers who started service with PGE providing them supply and planning for them. The charges proposed by PGE are not discriminatory due to these distinctions.

Should the Commission prefer to expedite PGE's NLDA program implementation, PGE's NLDA program should be approved including the proposed capacity charges and an

[4] UE 335 Order No. 18-464, Appendix B, At 2 & 3.
[5] UM 1837 Order No. 17-171, Appendix A, At 2.

additional mechanism, proposed conceptually by Staff, to largely avoid those charges through customer curtailment implemented through demand response program participation.

Q. Did parties raise additional issues in their opening testimony in this docket?

A. Yes. We have grouped the parties' issues by topic, and will address them as follows:

- **General Issues and Recommendations;**
- **Broader Resource Adequacy (RA) investigation;**
- **Discrimination;**
- **RAD Issues;**
- **The Resource Intermittency Charge (RIC);**
- **PGE's long-term Standard Offer Service;**
- **NLDA Cap and Queue Implementation Considerations;**
- **Miscellaneous Issues.**

II. Parties' Recommendations

Q. Does PGE agree with Staff's Primary Recommendation—the separate investigation--and proposed procedure?

A. Yes. As stated above, we agree in principle with Staff's proposal for a separate investigation provided that the Commission suspend PGE's proposed Schedule 689 tariff. We see the merit in Staff's proposal; however, it is important that the NLDA tariff be delayed given the importance of resolving the larger resource adequacy issues implicated and to ensure that costs are being allocated equitably, thus avoiding unwarranted cost and risk shifting to COS customers.

This approach seems consistent and supported by other parties.

Calpine testimony notes that:

> To the extent that the Commission wishes to address the issue of resource adequacy and capacity provided on behalf of NLDA customers (or direct access customers generally), a generic docket devoted to these issues is the more appropriate venue.[6]

Staff finds that:

> In addition to PGE's general comments about capacity and departed load, this is the primary reason why Staff believes that the RIC and the RAD as proposed by PGE would apply both to NLDA and LTDA customers.[7]

Lastly, AWEC states that:

> The RAD is intended to address resource adequacy issues associated with PGE's concern that "NLDA customers are not required to contribute toward the system's

[6] Calpine/100, Higgins/12: 6-9.
[7] Staff/100, Gibbens/8: 11-14.

reliability requirements ….”22/ However misguided this reasoning is (for the reasons discussed above), it applies equally with regard to NLDA and LTDA customers. Indeed, the only difference between these two groups of customers is that the former do not yet exist on PGE's system. There are no “resource adequacy” distinctions between the two groups that would justify applying the RAD to one and not to the other.[8]

Q. Do parties generally agree that the application of capacity charges to direct access customers should be considered in a subsequent investigation?

A. Yes. CUB argues that direct access as a whole must be revisited to require direct access customers to pay for the capacity necessary to operate the power system.[9] Staff, AWEC, and Calpine all agree that the obligation for direct access customers to support capacity needs should be studied in a general investigation.[10] We also support studying direct access capacity obligations and payments in a general investigation.

Q. If PGE participated in a general investigation into direct access, would that be a violation of the stipulation approved in Commission Order 19-129?

A. No. While the Stipulation and Commission order in Docket No. UE 335[11] would prevent PGE from proposing changes to the existing LTDA program before 2022, it does not prevent PGE from supporting changes to direct access policy that, if approved by the Commission, may then be implemented for LTDA effective in 2022. PGE supports future changes to direct access policy that allow for resource adequacy alignment between LTDA and NLDA tariffs.

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[8] AWEC/100, Mullins/10.
[9] CUB/100, Jenks/2: 3-5.
[10] AWEC/100, Mullins/9; Staff/100 Gibbens/11: 1-2; Calpine/100, Higgens/12: 6-12.
[11] UE 335 Order No. 18-464, Appendix B, At 2 & 3.

Q. Is there a compelling reason to implement PGE's NLDA program ahead of a general-investigation into direct access policy and resource adequacy?

A. No. While certain customers currently in PGE's NLDA queue may be inconvenienced by a delayed program implementation, PGE agrees with Staff that this potential inconvenience is outweighed by the priority to strive for the highest quality decision informed by all facts available.[12] While Calpine argues that queued customers eligible to purchase its services may be harmed by a delay to NLDA program implementation,[13] considerations for individual customers should not be elevated above the needs for durable, well-constructed policy and tariffs. The NLDA queue is a "non-binding" queue, and customers are free to remain in queue or may also take service from PGE and consider enrolling in LTDA.

Q. If the Commission were to extend the suspension of UE 358 or hold it in abeyance, pending the agreed upon investigation, would PGE support allowing customers in the queue to participate in NLDA (provided eligibility is met and there is room under the cap) after the investigation, even if they were to energize their operations while waiting?

A. Yes. This would take a Commission waiver of the one-year notification rule and PGE would not object to that, given the circumstances. However, we would expect that all other NLDA customer eligibility would remain intact, and the questions concerning direct access, resource adequacy, and fairness in paying one's fair share not be set aside during that time.

Q. Were the Commission to approve PGE's NLDA program as proposed within this docket, would such rates be discriminatory when compared to other customers?

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[12] Staff/100, Gibbens/11.
[13] Calpine/100, Higgens/41: 19-22.

A. No. A difference in rates or charges for a like and contemporaneous service is not discriminatory if those differences are based upon a difference in customer class. The PUC has determined that NLDA and LTDA customers are distinct customer classes[14], and thus, they may be subject to different charges even if the service appears to be under substantially similar circumstances. NLDA customers are distinguished from LTDA or COS loads by virtue of their size and 'unplanned for' nature (i.e. truly incremental load). Therefore, the costs associated with the RIC and the RAD may be recovered from NLDA customers, and PGE's proposed long-term standard offer service may be offered to NLDA customers as their service is uniquely distinguished from all other customer classes and rate schedules which PGE serves.

Q. What parties raised issues about discriminatory pricing?

A. Staff and AWEC both raised issues related to discriminatory pricing.

Q. What issues did Staff raise about discrimination?

A. Staff is concerned that the RIC and the RAD applying to NLDA customers and not LTDA customers may be discriminatory. Staff also raises the issue that if the Commission were to adopt fees for NLDA customers that may also, at some point, apply to LTDA customers, it could raise due process issues for LTDA customers. With regard to the RIC, Staff notes that direct access scheduling occurs for all direct access customers and imposing a charge only on NLDA customers may create discriminatory prices. For these reasons, and to allow input from all potentially affected parties, Staff's recommends a new investigation that includes both LTDA and NLDA programs.[15]

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[14] UM 1837 Order No. 17-171, Appendix A, At, 2.
[15] Staff/100, Gibbens/10.

Q. What discrimination issues does AWEC raise?

A. AWEC has similar concerns to Staff, stating that the NLDA and LTDA customers are indistinguishable from resource adequacy and scheduling perspectives and thus the RIC and RAD charges should be examined in a docket that applies to both NLDA and LTDA.[16]

Q. Does PGE agree with Staff and AWEC's positions premised on the belief that there is no reasonable basis to distinguish NLDA customers from LTDA? Please explain.

A. No. NLDA and LTDA customers have been recognized as distinct rate classes. The Commission has identified several distinguishing factors between the rate classes and adopted rules accordingly. First, the transition adjustments paid are dramatically different from each other; NLDA will only pay 20% of fixed generation costs; while LTDA customers pay 100% of fixed generation costs. Both services pay their respective transition adjustments for five years. Secondly, from a load/resource planning perspective, NLDA loads have not had any capacity resources acquired to support their service and reliability/resource adequacy (which PGE is requesting the ability to plan for direct access loads in this docket). In contrast, LTDA loads are loads that PGE had previously planned for and served by COS generation; the planning and service of such loads means PGE previously acquired generating and capacity resources to serve those loads. LTDA customers who are in their transition periods, are still contributing (through their transition adjustments) to energy and capacity resources planned and acquired for them. This is not the case with NLDA customers. For this reason, NLDA customers present a more acute and more immediate reliability impact than do the previously planned for and resourced LTDA customers. The third distinguishing factor between NLDA and LTDA customers is the

[16] AWEC/100, Mullins/9 & 10.

more sizable individual load threshold required for service; NLDA participation requires a minimum threshold of 10 MWa, while LTDA allows aggregation to 1 MWa (with each account of 250 kW). The size of the load adds to the increased reliability risks related to NLDA customers.

Q. Continue.

A. Furthermore, were Staff and AWEC's arguments regarding discriminatory rates between NLDA and LTDA customers be taken at face value, the argument would equally apply for discriminatory rates between direct access customers generally and all cost of service customers. Resource adequacy is a service PGE is obligated to provide to all customers regardless of their energy supplier. Currently, all COS customers pay for resource adequacy via their energy charges; however, resource adequacy is not separated out as a specific service on COS customer bills. Direct access customers, outside of their transition adjustment period, currently do not pay towards generating capacity or resource adequacy. As all customers receive the benefit of resource adequacy, only cost of service customers pay for this service, having a discriminatory and burdensome impact on cost of service customers.

Q. Regarding reference to transmission service, AWEC proposes revising the sentence in PGE's Schedule 689 that currently states: "[s]ervice under this schedule is limited to the first 119 MWa that applies to Schedule 689, or at an amount subject to the long-term transmission planning constraints of the Company". Does PGE agree with AWEC's proposed language?

A. Yes. PGE agrees with AWEC's proposed edit and will change the sentence to read: "Service under this schedule is limited to the first 119 MWa that applies to Schedule 689.

The timing of service under this schedule may be impacted by transmission capacity and planning requirements, consistent with the requirements of the Company's Open Access Transmission Tariff."

Q. Parties seemed confused by PGE's intent in calling out transmission planning. Why did PGE reference that in its filing?

A. We discussed transmission planning in our opening testimony to describe the constraints that may impact a NLDA customer's timing and to provide notice to parties that transmission planning horizons are have a long lead time and that PGE's available transmission capacity is finite.

Q. Staff, AWEC and Calpine recommend that PGE's NLDA program be approved without the RIC and RAD charges and be considered in subsequent investigation. Is it appropriate to implement the NLDA program without the RIC and RAD charges in advance of a broader resource adequacy investigation?

A. No. In Order No. 19-103 that opened UE 358, the Commission made the decision to investigate whether the RIC and RAD charges ought to apply to NLDA customers. Delaying the RIC and RAD decisions and approving Schedule 689 absent the RIC and RAD charges would communicate a price signal to customers absent the full costs they impose onto PGE's system and likely lead to the resource adequacy issues parties are attempting to resolve. We agree with the parties that a separate investigation would potentially help to streamline the range and scope of the RIC and the RAD and how it would apply to NLDA and LTDA; however, only if Schedule 689 is suspended as well, to ensure customers have accurate and transparent pricing.

III. Parties' RAD Issues

A. PGE's Proposal

Q. What is resource adequacy?

A. Resource adequacy is the ability of supply-side and demand-side resources to reliably serve load across a broad range of weather and other system conditions. It is an essential component of PGE's service and is a vital part of resource planning that enables safe, reliable electric service for customers. Moreover, PGE bears the responsibility for resource adequacy for the load in its balancing authority—no matter if the load is cost of service or direct access. This is PGE's provider of last resort responsibility.

Q. Which customer classes benefit from PGE's efforts to achieve resource adequacy?

A. All customers, including both COS and direct access customers, benefit from resource adequacy. Resource adequacy is a primary component of all electric supply reliability. Reliable electrical service is an essential service which benefits all users of the power system. Due to the interconnected nature of the transmission and distribution system, in addition to the requirement that all distribution customers be supplied on a non-discriminatory basis, all customers also share the risks related to service curtailments due to inadequate supply.

Q. How are costs associated with resource adequacy paid for by customers currently?

A. Currently, all COS customers pay for resource adequacy via the energy charges associated with PGE's production revenue requirement. However, resource adequacy and reliability costs are not called out as a specific service on COS customer bills.

Q. Do direct access customers currently pay for resource adequacy?

A. No. Direct access customers, outside of adjustment period transition charges, do not pay any costs related to PGE's production revenue requirement and do not contribute towards the costs of securing generating capacity and supporting resource adequacy. This is an issue with long term direct access. PGE plans for the short term direct access loads and the short term direct access customers continue to pay transition adjustments and thus, contribute to capacity resources, contributing to resource adequacy.

Q. How does PGE propose that NLDA customers contribute to resource adequacy costs?

A. PGE's proposed NLDA tariff assesses a RAD charge on all NLDA customers to recover the costs of assuring resource adequacy for NLDA customers.

Q. How does PGE propose to calculate a RAD capacity charge?

A. Through a cost of service study in a future General Rate Case, we propose to institute a new nonbypassable "reliability service" functionalized category which will capture the costs associated with providing resource adequacy. Our proposal will assign costs related to capacity supporting resource adequacy to all schedules based on cost causation from the COS study.

Q. Is PGE proposing that all customers, including COS customers, contribute toward resource adequacy costs?

A. Yes. PGE's NLDA program would recover resource adequacy costs from NLDA customers. In the future, PGE intends to propose recovery of resource adequacy costs from LTDA customers. As stated above, COS customers are already paying for resource adequacy, but currently PGE's COS study does not directly functionalize resource adequacy. Our proposal seeks to identify this new function within the COS study, but it does not create additional or new resource adequacy charges for COS customers.

Q. With regard to the RAD and the energy supply return charge, if the RAD is approved, is it still necessary to calculate the rate impact for existing COS customers and subsequent energy supply return charge if necessary?

A. Yes. While Staff questions whether the energy supply return charge is necessary if the RAD is approved, the energy supply return charge is not a capacity related charge. The energy return charge is calculated in the event that a customer returning to COS or PGE's Market Energy Option results in an increase to existing COS customers rates of more than 0.5%.[17] The principle behind the energy supply return charge is to prevent material cost shifting onto COS customers and ensure that any direct access customers pay for the costs they impose by returning to COS or the Daily Market Energy Option.

B. Parties' Proposals

Q. Does Staff find PGE's resource adequacy concerns reasonable?

A. Yes. Staff notes that PGE's capacity concerns are reasonable given capacity constraints in the Northwest. Staff recognizes the legitimacy of the capacity resource implications raised by PGE.

Q. Please summarize Staff's position with respect to PGE's proposed the RAD charge.

A. Staff concurs with PGE's concerns regarding resource adequacy and the failure of ESSs to plan for resource adequacy while PGE and its customers remain responsible for the associated costs.[18] Staff agrees that current policy would require PGE and its customers to cover the costs related to resource adequacy and that the provision of emergency service to

[17] See PGE Advice No. 19-02, At 8.
[18] Staff/100, Gibbens/13: 11-17.

ESSs could result in a cost shift between NLDA and COS customers.[19] While Staff acknowledges the merits for a RAD charge, Staff argues that the cost of such service appear extreme.[20] Staff surmises that there may be more cost-effective means for NLDA customers to support resource adequacy including building on-site generation, electing for prioritized load service curtailment, or ensuring ESSs plan and procure to meet not yet established resource adequacy standards.[21] Ultimately, Staff offers an alternative recommendation (should the Commission choose not to adopt Staff's procedural recommendation of a broader investigation) that NLDA customers be charged PGE's proposed RAD charge but be given the option to avoid the charge by electing for prioritized load curtailment.[22]

Q. How do you respond to Staff's ideas for avoiding the RAD charge?

A. Staff's alternative recommendation is reasonable, subject to clarification of some of the concepts. PGE's ability to prioritize the curtailment of direct access customers can be consistently operationalized through industrial customer participation in a demand response program. Were customers to participate in such a program, the customer could receive monthly or annual payments to offset PGE's proposed RAD charge. PGE supports a NLDA program with a required RAD charge, while simultaneously providing all customers the opportunity to manage any net cost impacts through demand response participation which includes customer incentive payments.

Q. How does PGE respond to Staff's concerns about the RAD price?

A. The costs related to supporting resource adequacy are indeed high relative to the remainder of a direct access customer bill. The magnitude of the proposed RAD charge is not itself

[19] Id.
[20] Staff /100, Gibbens/16: 1-6.
[21] Staff/100, Gibbens/18: 13-20.
[22] Staff/100, Gibbens/19: 12-17.

unreasonable – the upper estimate PGE provided is based on the same cost of generic capacity routinely studied in PGE's IRP process. Instead, the appearance of a high reliability-based charge relative to a direct access customer bill demonstrates the magnitude of the cost and risk shifting currently being borne by COS customers. Cost of service customers currently pay comparable amounts to support resource adequacy, yet the benefits are distributed to direct access customers that do not contribute to cost recovery. Additionally, as we explained in our opening testimony, the RAD charge will ultimately depend on the cost of the capacity acquired to support it.

Q. Please summarize CUB's position with respect to the RAD charge proposed by PGE.

A. CUB supports PGE's proposed RAD charge. CUB argues that without a mechanism for ESSs to secure capacity in a wholesale market, akin to the capacity markets in RTOs like PJM, there remains a structural imbalance between regulated tariffs which include the fixed costs of generation and competitive marketers who are free to price products at the short run marginal cost of the wholesale energy market.[23] Recognizing this structural imbalance, CUB supports application of capacity charges to NLDA customers to ensure those direct access customers are fairly contributing toward the fixed costs associated with maintaining reliability.[24] CUB argues further that simply assessing capacity charges on direct access does not unwind the full extent of the costs shifts faced by COS customers due to eligible customers' direct access participation. CUB recognizes that the capacity charges would not recover the all fixed costs necessary borne by utilities and avoided by ESSs through limited participation in the wholesale energy market. These remaining fixed costs include all fixed

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[23] CUB/100, Jenks/15: 17-23.
[24] CUB/100, Jenks/16: 23-25.

costs not strictly related to resource adequacy, including the fully allocated embedded costs cost of PGE's energy and renewable resources.[25]

Q. How do you respond?

A. We agree with CUB's characterization that the fixed costs of generation are being borne by utility COS customers.[26] Without regional retail customers bearing the fixed resource cost of generating resources, resources would largely not be available to create supply in the wholesale market.[27] We believe that the larger market distortions benefiting direct access customers and the broader scope of fixed costs avoided by direct access customers should be considered in a broader Commission investigation into direct access policy.

Q. Please summarize AWEC's position with respect to the RAD charge proposed by PGE.

A. AWEC does not support PGE's proposed RAD charge, arguing that the RAD is not an effective means to support reliability, would violate direct access law, and is inconsistent with cost-causation principles.[28] AWEC does agree that PGE has the exclusive responsibility to ensure reliability as a balancing authority,[29] and that if curtailment is required, it must be performed in a fashion that affects COS and direct access customers equally.[30] However, AWEC argues that PGE's direct access load is small relative to the regional peak load that therefore direct access customers have no direct effect on system reliability.[31] AWEC argues that the availability to secure capacity from the wholesale

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[25] CUB/100, Jenks/13: 6-19.
[26] CUB/100, Jenks/11.
[27] Id.
[28] AWEC/100, Mullin 5.
[29] AWEC/100, Mullins/8.
[30] AWEC/100, Mullins/8.
[31] AWEC/100, Mullins/7.

energy market is not fundamentally limited[32] and the ESSs' power purchases support resource adequacy.[33]

Q. How do you respond?

A. AWEC's arguments do not hold up to simple scrutiny. To suggest, as AWEC has done, that PGE's COS customers have a greater impact on system reliability and a greater responsibility to support reliability than direct access customers is at odds with fundamental notions of cost causation – all electrical load impacts system reliability whether that load is demanded by a COS customer or a direct access customer.[34] AWEC suggests that ESSs do contribute to resource adequacy, but this assertion is contradicted by the record. ESS practice is to rely on short-term market purchases, to not contract for specified resources and to rely on financial damages to excuse non-delivery. Such practices do not support regional reliability and resource adequacy.

AWEC's suggestion that "there is no circumstance in which PGE alone would face inadequate supply while all other utilities in the region remain balanced"[35] is incorrect. In fact, as a balancing authority operator PGE has an obligation to maintain balance within its system and may be required to curtail service if it is unable to secure supply to balance load rather than freely leaning on the remaining balancing authorities, as AWEC suggests. Should regional utilities secure prioritized access to available capacity resources ahead of PGE, regional utilities could remain balanced while PGE curtails service. In this way, our regional capacity planning, procurement, and deployment process is not unlike a game of musical chairs – AWEC would have the Commission believe that failing to procure capacity

[32] See PGE Exhibit 201.
[33] See PGE Exhibit 202.
[34] See PGE Exhibit 203.
[35] AWEC/100, Mullins/6.

for direct access load could not possibly leave PGE's customers without a chair and that PGE will always be able to rely on market purchases to meet any capacity need. That is incorrect.

Q. AWEC argues that the incremental capacity resulting from the RAD would have little impact on system reliability. Does PGE agree?

A. No. AWEC is incorrect that incremental capacity resulting from the RAD would have little impact of system reliability. PGE estimates that 373 MW of additional incremental capacity resources are necessary to support the reliability needs of existing direct access customers.[36] Recently performed regional resource adequacy assessments have found that in 2023 approximately 500 MW of new capacity resources are necessary to maintain resource adequacy standards in the Northwest.[37] Clearly, securing capacity for direct access customers would make a meaningful contribution to the regional capacity needs.

Q. Please summarize Calpine's position with respect to the RAD charge proposed by PGE.

A. Calpine does not support PGE's proposed RAD charge but welcomes a close examination of ways in which direct access customers and ESSs could contribute toward system reliability without purchasing capacity from PGE. Calpine requests clarity on whether PGE's proposed RAD charge would make capacity available to support a circumstance in which a NLDA customer would return to cost of service unexpectedly or in the event that physical power is unavailable to back an ESSs market purchases.[38] Calpine supports consideration of

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[36] See PGE's 2019 IRP, Chapter 4, Section 4.7.3.1 Direct Access Capacity Adequacy Sensitivities, at 125.
[37] Pacific Northwest Power Supply Adequacy Assessment for 2023, June 2018 (Report by Northwest Power and Conservation Council), page 6. https://www.nwcouncil.org/sites/default/files/2018-7.pdf.
[38] Calpine/100, Higgins/9: 16 -23.

changes in direct access curtailment priorities[39] and mechanisms for which direct access customers would be required to support resource adequacy though ESS supply of capacity products[40] however Calpine argues that PGE's RAD charge, as proposed, is in conflict with Oregon's direct access statutes.[41]

Q. How do you respond?

A. As stated above, PGE supports an investigation to examine the resource adequacy responsibilities of direct access customers. PGE maintains that the RAD is necessary to address both hypotheticals posed by Calpine: 1) if a direct access customer unexpectedly returns to COS prior to the NLDA notice window, PGE requires capacity to meet the need on an immediate basis. 2) If an ESS fails to deliver energy during a period of peak demand, PGE requires additional energy to backfill the ESS's under delivery with a physical source of capacity. We discuss alternatives to RAD charges later in this testimony.

Q. Does Calpine offer any additional details with respect to how its current operations contribute toward PGE's resource adequacy needs?

A. Yes. Calpine's testimony and response to data requests reveal that the ESS' current operations do not support PGE's or the region's resource adequacy needs. Calpine's disclosures call to question what 'service' Calpine is offering to its customers and whether it is in keeping with what was contemplated under SB 1149. As PGE will discuss in further detail, Calpine's service does not include generating electricity or securing capacity resources. Calpine's service does not include any management of customer day-ahead or hour-ahead load forecasts or any actions to address how its individual customers' demand

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[39] Id.
[40] Calpine/100, Higgins/12: 5-18.
[41] Calpine/100, Higgins/11: 9-20.

differs from monthly averages. Instead, Calpine's service is limited to the purchase of commodified electric products and financial hedging products from brokers, exchanges and banks months or years ahead of actual flow. The actual power delivery process is left to unspecified market entities with PGE responsible to cover any and all operational gaps while Calpine's counterparties are only responsible for whatever financial damages may apply. While there is nothing improper in offering these limited services to the competitive market-place, it cannot be reasonably be assumed to be a comparable level of service to that provided by PGE – the cost of which is avoided by direct access customers. SB 1149 created provisions to encourage the divestiture and separation of electrical power generation from distribution utilities and encouraged competitive entities to provide depth and liquidity to the wholesale market. Calpine's services do not accomplish this stated goal. Rather Calpine acts as an intermediary, making relatively risk-free energy purchases at the short run marginal cost from generators paid for by regional retail utility customers.

Q: Specifically, what market purchases and resources does Calpine rely upon to provide its service to its direct access customers?

A. In response to DR 006,[42] Calpine disclosed that as of January 1, 2018 it held no long-term power supply agreements, and in August 2018, Calpine served nearly [redacted] MWa of load ([redacted] MWa annually).[43] For every one of these hours, Calpine relied upon term wholesale power purchases for blocks of on-peak and off-peak power. These purchases were made on a calendar or monthly basis, meaning that the purchases were made at a constant volume for all on-peak and off-peak periods for the year or month.[44] In 2018, Calpine did not make a

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[42] See PGE Exhibit 204.
[43] See PGE Exhibit 205C.
[44] See PGE Exhibit 206.

single purchase in the hour-ahead or real-time market.[45] Any difference between the volumes purchased by Calpine on a yearly or monthly average basis and actual Calpine customer load were balanced by PGE. Furthermore, by the virtue of relying wholly on yearly or monthly term transactions, Calpine's purchased product was, by definition, not associated with a specified physical resource.

Q. Why are the details of Calpine's procurement to meet direct access loads, important?

A. This is important because Calpine's purchase does not include an assurance of available capacity from any generator. In fact, prior to day-ahead scheduling, Calpine and PGE are unaware which resource or system will ultimately be used to supply the delivery by which point the title chain process may have led to numerous transfers of delivery responsibility. Further, consistent with the form agreements under which these commodities are exchanged, should the ultimate counterparty responsible for delivering the energy product purchased by Calpine fail to do so, Calpine or PGE is not entitled to any physical replacement resource. Instead, under the agreement, failure to deliver is addressed through financial damages settled at prevailing index prices, which, at the time of need, is of little use to PGE. Under such conditions, PGE continues to have the responsibility to serve load in its balancing authority and must backfill the delivery failure with a physical resource. This is not a theoretical problem. Rather, it is an urgent issue that is presently undermining the reliability of PGE's power system. In August 2018, a certain percentage of Calpine's purchased power deliveries were ultimately sourced by the CAISO following a series of title chain transfers made after Calpine purchased a term power product.[46] CAISO has a published and

[45] See PGE Exhibit 207.
[46] See PGE Exhibit 208.

recognized business practice of curtailing exports to prevent or alleviate a capacity shortfall within the CAISO balancing authority, such a curtailment of Calpine's purchased energy during a peak event in PGE's BAA would impose costs and reliability risks to PGE's COS customers.

C. Alternatives to the RAD

Q. When developing PGE's proposed NLDA program, did PGE consider alternative means for direct access customers to support resource adequacy without a RAD capacity charge?

A. Yes. PGE considered alternative measures including the curtailment of NLDA customers and the requirement for ESS to self-supply capacity resources. For reasons described below we determined that securing capacity on behalf of NLDA customers and charging those customers a non-discriminatory capacity charge is in the public interest and most aligned with Commission policy and Oregon law.

Q. Did parties raise alternative methods for ensuring resource adequacy during peak system events?

A. Yes. Both Staff[47] and Calpine[48] raised the possibility of voluntarily reducing or "curtailing" direct access customer loads. Staff suggested that NLDA customers ought to have a curtailment option available to them as an alternative solution to the RAD charge[49]. Calpine also references curtailment as a possible alternative but does not provide a specific proposal. Staff also consider whether the presence of on-site generation would replace the need for the RAD capacity and charge. Staff, AWEC, and Calpine also support further consideration of

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[47] Staff/100, Gibbens/18 & 19.
[48] Calpine/100, Higgins/9.
[49] Staff/100, Gibbens/18.

requirements for direct access customers to supply capacity through resource adequacy requirements for ESSs (e.g. "self-supply").

Q. Does PGE agree that direct access customers can contribute toward resource adequacy through voluntary curtailment?

A. Yes. Demand side management is an essential tool for managing and meeting resource adequacy needs. It is unclear what specific curtailment protocols Staff, AWEC, and Calpine would consider, but PGE strongly supports direct access customer participation in a demand response program. Following small changes to PGE's Schedule 26, direct access customers would be able to execute a Firm Load Reduction Agreement and be eligible to receive monthly payments that would manage or effectively offset the proposed RAD charge depending on the chosen performance parameters with respect to the notification period and maximum curtailment hours per season. To avoid confusion, participating in a demand response program would not exclude NLDA customers from RAD charges. Rather NLDA customer bill impact would be partially or fully offset by monthly payments made by PGE to the customer associated with their participation in PGE's demand response program.

In contrast to voluntary demand response, PGE cannot simply curtail service to direct access customers during periods of inadequate supply. As described in PGE's response to AWEC data request 18,[50] curtailment of service can be operationalized through demand response participation but may not be feasibly implemented through distribution level switching curtailment. Further, PGE does not have the authority to curtail direct access customers in a discriminatory manner and must curtail direct access customers equally with COS customers when engaging in curtailment under Rules C and N.

[50] See PGE Exhibit 209.

Q. **Does PGE agree that direct access customers could contribute toward resource adequacy through on-site generation?**

A. In principle, NLDA customers could contribute to resource adequacy using on-site generation. In order to contribute to resource adequacy, PGE would need access and control of the onsite generation in a fashion that is similar to PGE's distributed standby generation program detailed in Schedule 200. There are a number of reasons why on-site generation may not substantially replace the need for RAD capacity including availability issues, energy limitations, and control requirements. Nonetheless, PGE supports further consideration of the use of on-site generation to support resource adequacy for direct access customers as a part of a general investigation.

Q. Does PGE agree that direct access customers should contribute toward resource adequacy through the self-supply of capacity resources?

A. No. PGE maintains that addressing reliability needs through the planning and procurement processes performed by PGE provide the greatest social benefit and is most consistent with Commission policy and Oregon law. Splitting capacity procurement responsibilities between PGE and ESSs is possible, but adverse to the public interest.

Q. Why is it in the public interest for PGE to remain solely responsible for supporting resource adequacy on its system?

A. PGE is best suited to act as the provider of resource adequacy because PGE: 1) can support system wide resource adequacy at lower cost; 2) use an effective combination of resources, including demand side measures, to support resource adequacy; 3) has exclusive responsibility for reliability and control of the balancing authority; and 4) is actively regulated under broad Commission authority including transparent and public disclosure.

PGE's provision of resource adequacy is necessarily more efficient and lower cost than ESS self-supply, because PGE can use the load and resource diversity of its system to diminish the required incremental capacity necessary to meet direct access customer resource adequacy needs. PGE can further reduce costs and serve the public interest through the use of a diverse portfolio of supply and demand side measures to meet capacity needs across PGE's balancing authority.

PGE is uniquely positioned as exclusive operator of the balancing authority responsible for reliable service. An ESS that self-supplies capacity but does not grant PGE's balancing authority the necessary operational control would create seams or limitations and may not actually provide a product in service to ensuring reliable service.

Lastly, as a public utility, PGE is subject to broad Commission authority that does not apply to an ESS. The Commission's authority includes the ability to compel PGE to act to promote safe and reliable service, the ability to enforce compliance with the Commission's rules and standards, and power and practice to ensure that PGE engages in public and transparent resource planning in service of supporting resource adequacy.

Q. Why is it not in the public interest for ESSs to self-supply capacity resources?

A. In addition to the issues listed above, the ability for ESSs to be effective and reliable sources of capacity is critically undermined by ESSs' limited accountability and limited regulatory oversight. ESSs are not public utilities and have no formal responsibilities to support safe and reliable service. ESSs cannot be compelled to comply with resource adequacy standards should they be deemed non-compliant with yet undefined standards. ESSs engage in limited reporting and do not engage in a transparent planning or procurement process. Lastly, unaccountable for the reliability of the system, an ESS will always remain incentivized to diminish the quality and reliability of their capacity position in order to lower costs while distributing reliability risks onto all users of the system.

Q. Is requiring ESS to pay for resource adequacy a violation of direct access law?

A. PGE will return to this issue in legal briefs. While we are not attorneys, direct access administrative rules and related statutes do not appear to prohibit direct access customers from paying for capacity resources procured by the distribution utility.

V. Parties' RIC Issues

Q. Please summarize parties' testimony on the Resource Intermittency Charge (RIC).

A. AWEC and Calpine argue that the RIC is unnecessary as under-scheduling does not currently pose an issue to COS customers or the PGE system. Staff acknowledges that under-scheduling is a problem and states that "it does believe that there are costs associated with reserving capacity to meet BAA system requirements."[51] CUB acknowledges this issue and supports the adoption of the RIC: "PGE's proposed RIC addresses this capacity problem in the current short-term market…CUB urges the Commission to adopt these proposals."[52]

AWEC, Calpine, and Staff each take the position that the RIC is duplicative of the RAD and/or double charging for services already procured and paid for under PGE's Open Access Transmission Tariff (OATT), specifically Energy Imbalance service provided under Schedule 4R.

AWEC and Staff both contend the RIC is discriminatory because it does not apply to LTDA. Both parties also argue the RIC does not create the proper incentive to reduce under-scheduling events and may create unintended behavior.

Staff and Calpine argue the RIC does not follow cost causation principles because the charge is assessed to the NLDA customer when the cause of the root problem the RIC is aimed at addressing is not a result of the customer's behavior and the customer cannot avoid the charge.

Q. Do all parties appear to fully understand PGE's proposed implementation of the RIC?

[51] Staff/200, Soldavini/14.
[52] CUB100, Jenks/17.

A. Not completely. Based on parties' testimony regarding the application of the RIC, it appears that there is confusion regarding when the RIC is applied and to which entity; how the RIC adjusts according to the magnitude of under-scheduling; and which supply options are subject to the RIC.

Q. Does the RIC apply to all customers if only one ESS under-schedules?

A. No. The RIC applies only to the customers served by the ESS that under-scheduled during the period in question. All other customers would not be assessed the RIC. PGE's NLDA advice filing stated "PGE's proposal does not distinguish the cost by ESS, and this charge is applied regardless of the scheduling practices of the customer's specific ESS."[53] In other words the dollar value charge of the RIC, as opposed to its application, is not specific to each ESS. The $/kw-month RIC charge would not be calculated individually for each ESS but instead is consistent across all direct access customers regardless of ESS.

Q. Does the RIC respond to changes in behavior, like reduced under-scheduling magnitude and number of events?

A. Yes. As we detailed in our opening testimony, "we intend to update the RIC according to the above-detailed methodology on a regular basis…"[54] By updating on a regular and frequent basis, the Renewable Energy Capacity Planning (RECAP) analysis that underlies the RIC will produce results that account for the reduced amount, in MW, of under-scheduling, and the reduced number of under-scheduling events.

Q. Staff asks for clarification on the application of the RIC to the two company supplied options[55]. Please explain how the RIC applies to these options.

[53] OPUC Advice No. 919, at 7.
[54] PGE/100, Sims - Tinker/14-15.
[55] Staff/200, Soldavini/13.

A. As we stated in our opening testimony, "The RIC applies to all supply options under NLDA, which includes the PGE proposed company supply options."[56] In the event PGE under-schedules NLDA load served under the company supply options, the RIC would trigger for only the NLDA customers served under those options. As we stated above, one entity triggering the RIC will not cause it to apply to all customers regardless of their service provider. Additionally, the RIC will adjust over time to reflect changes in the scheduling behavior of both PGE and ESSs.

A. The RIC is Necessary

Q. Please summarize AWEC and Calpine's analysis regarding under-scheduling behavior?

A. AWEC states that there is no evidence supporting chronic ESS under-scheduling and "in fact, the opposite is true."[57] Calpine has a similar position asserting that the amount of under-scheduling is not surprising nor is it concerning because "over the 2016-2018 period the average amount of under-scheduling of LTDA load was just 8 MW on 219 MWa of LTDA load."[58]

Q. Does PGE agree with AWEC and Calpine's analysis?

A. No. Both parties rely on annual averages to argue under-scheduling is not occurring or poses no issue. PGE analyzed historic scheduling behavior for calendar year 2018 and found that ESSs consistently under-scheduled during the highest load hours of the year. Table 1 below shows this practice:

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[56] PGE/100, Sims - Tinker/14.
[57] AWEC/100, Mullins/17.
[58] Calpine/100, Higgins/14.

Table 1

Highest Load Hours	Percentage Under-Scheduled
200	100.0%
400	95.0%
600	90.7%
800	87.5%
1000	85.2%
2000	75.7%

In its testimony, AWEC acknowledges that "PGE's data does show, however, that ESSs tend to under-schedule in times of peak demand", although it does not agree that under-scheduling is an issue.[59] Calpine also compares the 2016-2018 maximum one-hour under-scheduling event of 71 MW to PGE's Balancing Authority Area load,[60] but fails to acknowledge that direct access actual load in that same hour was 179 MW which means Calpine supplied only 60% of its customers' required energy.

Q. What are the impacts to PGE when ESSs under schedule during times of peak demand?

A. When ESSs under schedule during times of peak demand, PGE is faced with supplying the deficit energy to direct access customers on a real-time basis in a capacity constrained market. In many cases, we supply that energy deficit to direct access customers via generating resources and/or long-term contracts which have been paid for by COS customers. As stated in our opening testimony, the issue the use of utility capacity resources paid for by COS customers poses cost shifting and reliability risks onto COS customers.

Q. Do Staff and CUB recognize that ESS under-scheduling imposes costs on COS customers?

[59] AWEC/100 Mullins/17.
[60] Calpine/100 Higgins/14.

A. Yes. CUB states in its testimony "The RIC ensures that the balancing authority has the capacity to meet its obligation when the ESS under-schedules its power. If the ESS has enough current capacity to service its load, then it can use that capacity to avoid under-scheduling."[61] Staff states in its testimony that it "agrees that there are real costs associated with reserving capacity to serve the load of Direct Access customers when an ESS under scheduled load, and also agrees that capacity paid for by COS customers should not be used to subsidize these customers…"[62]

B. The RIC Will Not Result in Double Charging and is Not Duplicative

Q. Please summarize the parties' positions on this topic.

A. Staff's position is that by paying for the RAD, "customers will then have paid for PGE to acquire the necessary capacity to serve that customer…and the incremental capacity needed to serve the intra-hour variability …should already exist" and some portion of the RIC and RAD may be duplicative.

AWEC opposes the RIC claiming it is duplicative of the charges already assessed to ESSs under PGE's OATT and will result in double charging.

Calpine's arguments against the RIC appear limited to the claim that the charge is duplicative if NLDA customers must also pay the RAD.[63]

Q. How are the RIC and the RAD distinct?

A. The RIC and the RAD are fundamentally different capacity products. PGE explained this in its response to OPUC DR 003.[64] The premise of the RAD is the need for peaking capacity

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[61] CUB/100 Jenks/17.
[62] Staff/200, Soldavini/5.
[63] Calpine/100, Higgins/18.

while the RIC service requires sufficiently flexible capacity. We also explained that providing RIC service is not expected to create a need for additional peaking capacity beyond what is required to provide RAD service.

Q. Does PGE agree with Staff's assertion that "at least some portion of the capacity that was acquired through assessment of the RAD should be flexible enough to serve the load the RIC charges for"?

A. No. While we stated in our Response to OPUC DR 003 that "capacity procured for meeting peaking resource adequacy needs may or may not be capable of supporting RIC related service"[65], commonly the flexible characteristics associated with the RIC are a distinct product or come at a premium, compared to the characteristics associated with the RAD. It is reasonable to assume that the procurement process and subsequent prudence review would ensure that PGE procures the least cost, least risk resource capable of meeting the RAD related needs. Additionally, PGE is not proposing to acquire capacity for the RIC. Instead it is proposing to address the cost shift: the RIC serve as a mechanism to compensate COS customers for their capacity that is being used to cover ESS under-scheduling events. While PGE does not agree with Staff's general assessment that the "RAD *should* be flexible enough to serve the load the RIC charges for", if overlap could be demonstrated, it would be easily addressed through the cost allocation process by ensuring that only the RAD related need/capability is allocated to direct access customers.

Q. With regards to concerns that the RIC is duplicative of PGE's OATT charges, does the RIC charge recover the same costs as the OATT?

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[64] See PGE Exhibit 210.
[65] Id.

A. No. AWEC contends that the services provided under the OATT, specifically energy imbalance service and regulation and frequency response service "present a comprehensive capacity product that the RIC would duplicate."[66] Regarding regulation and frequency response service, AWEC portrays this service, as well as its purchase of other ancillary services, as broadly covering all of the capacity needs associated with under-scheduling events. Schedule 3 of PGE's OATT clearly characterizes regulation and frequency response as "necessary to follow the moment-by-moment changes in load" and that such service is provided by "committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment) and by other non-generation resource capable of providing this service…" Although AWEC does not characterize it as such, this language is clearly referring to minor changes in load that occur over a granular timestep rather than hours or sustained periods of scheduled supply that is insufficient to meet load.[67]

As PGE explained in its opening testimony, OATT Energy Imbalance Service does not compensate COS customers for the capacity required to manage under-scheduling events. This fact is clear as the price for such service is based on a market energy price, not capacity. Furthermore, the EIM, the market that produces the energy price index for PGE's Schedule 4R, is an imbalance energy market only and does not provide capacity. Staff agreed that Schedule 4R does not recover capacity in its testimony: "as PGE notes in its testimony, the amount recovered through the OATT is based on a 'market index not necessarily the cost of providing the energy.' Staff agrees with the Company's assertion that

[66] AWEC/100, Mullins/14.
[67] PGE OATT, Schedule 3.

short term day ahead market may not include the costs associated with making adequate volumes of capacity available."[68]

AWEC also points to the CAISO 125% and 200% of load aggregation point (LAP) price charges for significant under-scheduling[69], but fails to recognize that CAISO assesses these charges only if "the metered Demand within an EIM Entity Balancing Authority Area exceeds the EIM Base Schedule of Supply submitted by the EIM Entity." by more than 5% or 10%, depending on the charge level. An EIM Entity is defined as "A Balancing Authority that represents one of more EIM Transmission Service Providers" which is the entire PGE BAA inclusive of direct access loads.[70,] That percentage deadband translates to approximately 100-250 MWa for PGE's average BAA load or 180-400 MW for PGE's peak BAA load, encompassing all of the existing direct access under-scheduling and the current direct access program itself.

Q. Are there additional provisions of the CAISO tariff that relate to the charges AWEC highlighted in its testimony?

A. Yes. The CAISO Tariff also provides an exemption to these penalties:

> an EIM Entity will be exempt from under-scheduling…if it uses the Demand Forecast prepared by the CAISO in its EIM Resource Plan and it approves EIM Base Schedules for its resources within +/-1% of the CAISO Demand Forecast.[71]

Because PGE uses the CAISO Demand Forecast, as most EIM entities do, and because ESS schedules are treated as the forecast of direct access loads, PGE will always submit schedules to balance to within 1% of the CAISO Demand Forecast because the remaining load is assumed to be PGE COS load by definition.

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[68] Staff/200, Soldavini/4.
[69] AWEC/100, Mullins/15.
[70] CAISO Tariff Section 29, 11(d)
[71] Id.

C. The RIC is Not Discriminatory

Q. What concerns did parties raise about the RIC being discriminatory?

A. Staff notes that direct access scheduling is applicable to all direct access customers and imposing a charge only on NLDA customers may create discriminatory prices. AWEC has similar concerns to Staff that the RIC charge applies to both NLDA and LTDA.

Q. Does PGE agree with AWEC and Staff's assessments?

A. No.

Q. Why is the RIC not discriminatory?

A. As discussed above, the charges proposed by PGE are not discriminatory due to this distinction between direct access customer classes, which generally enables the NLDA program.

D. The RIC Will Appropriately Incentivize Accurate Scheduling

Q. Please summarize the parties' positions on this topic.

A. Staff theorizes that the RIC "may instead serve as a disincentive to choosing NLDA service" and that ESSs "will have less incentive to improve scheduling practices as the RIC is triggered by how well ESSs schedule in aggregate."[72] AWEC contends that Energy Imbalance Service under OATT Schedule 4R "removes any incentive for an ESS to significantly under- or over-schedule" and implementing the RIC will create a "greater incentive to over-schedule…to avoid the RIC."[73]

Q. Does PGE agree with these positions?

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[72] Staff/200, Soldavini/11-12.
[73] AWEC/100, Mullins/15-16.

A. No. As we detailed above, Staff's analysis is based on an incorrect understanding of how the RIC is triggered and applied. The RIC does not apply to all ESSs if one ESS under-schedules. AWEC is also incorrect in its assertion that Schedule 4R provides a sufficient incentive. Ignoring the issues of the use of COS customer paid-for capacity, Table 1 above and Table 2 below clearly demonstrate that Schedule 4R is not a sufficient incentive mechanism.

Q. How does the RIC serve as an appropriate incentive?

A. The RIC acts as an incentive to ensure accurate scheduling of supply and provides a mechanism to compensate COS customers when such inaccuracies result in COS capacity being used to supply direct access customers. An ESS would not be incentivized to regularly over-schedule because that would require it to procure excess energy, exposing the ESS, and likely its customers (via a pass through) to the additional cost of procurement as well as the potential price spread between the OATT Schedule 4R energy index and the cost at which the energy was procured. As further support, attached is PGE's response to AWEC DR 010.[74]

Q. AWEC suggests that the RIC should be symmetrical such that it provides a credit when ESS over-scheduling occurs. Does PGE agree?

A. No. PGE's Responses to AWEC DR 005 explains why compensation for over-scheduling is inappropriate. Essentially, ESS over-scheduling events cannot be relied upon with any degree of certainty that could allow PGE to reduce its need to have capacity available to cover the possibility of under-scheduling occurring. Additionally, PGE's RECAP analysis demonstrates that accounting for ESS over-schedules in addition to under-schedules does

[74] See PGE Exhibit 211.

not materially reduce PGE's RIC related capacity needs. In other words, over-scheduling behavior produces no meaningful capacity contribution. As seen in Table 2 below, analysis of 2018 historical data further supports the finding of the RECAP analysis by demonstrating that ESSs tend to over-schedule in the *lowest* need hours where PGE either has no need or must have capacity available to back down in order to accommodate the over-scheduling.

Table 2

Lowest Load Hours	Percentage Over-Scheduled
200	90.5%
400	86.3%
600	79.8%
800	77.3%
1000	75.6%
2000	65.2%

Additionally, it would be inappropriate to pay ESSs a capacity payment for procuring additional energy via the short-term wholesale market, rather than actual capacity. PGE's OATT Schedule 4R already provides the appropriate energy compensation.

Q. Is the RIC a disincentive to choosing NLDA service?

A. No. Staff's position is based on incorrect assumptions that when the RIC is triggered it applies to all ESSs and NLDA customers have no influence over their potential ESS' scheduling practices.[75] We addressed the former earlier in our testimony and the latter below. The RIC is applied to all options under NLDA and, simply put, is meant to compensate COS customers for the capacity they have paid for that direct access customers are currently using for free. It is aimed to address cost shifting by cost contribution. Staff recognized this in its testimony, and "agrees that capacity paid for by COS customers should

[75] Staff/200, Soldavini/11-12.

not be used to subsidize those customers who have chosen to leave PGE's system."[76] Our position is that without the RIC, an incentive continues to exist for direct access customers to receive services at the expense of COS customers.

E. NLDA Customers Avoiding the RIC

Q. Please summarize the parties' positions on this topic.

A. Staff articulates its concerns that the RIC charge is "not truly avoidable" because it does not directly apply to the ESS and the NLDA customer does not actually have the ability to avoid the cost through any action of its own because the customer does not control ESS scheduling amounts; ESS schedules are submitted in aggregate for all of a particular ESS' customers; and the customer does not have access to real-time information in order to decrease load accordingly[77].

Q. Can the RIC charge be avoided?

A. Yes. As we detailed in our opening testimony, "PGE is proposing that for billing periods where there are no under-scheduling events…the RIC will not be assessed."[78] Additionally, CUB reinforces this concept in its testimony, "If the ESS has enough current capacity to service its load, then it can use that capacity to avoid under-scheduling."[79]

Q. Staff states "the customer does not actually have the ability to avoid the [RIC]."[80] Do you agree?

[76] Staff/200, Soldavini/5.
[77] Staff/200, Soldavini/10.
[78] PGE/100, Sims – Tinker/14.
[79] CUB/100, Jenks/17.
[80] Staff/200, Soldavini/10.

A. No. As Staff acknowledges, "large, sophisticated customers such as those who will elect service under the NLDA program are able to weigh their energy supply options and make the best decision for their individual needs."[81] By extension, these same customers are also sophisticated enough to negotiate their supply agreements with prospective ESSs and could easily include performance requirements relating to scheduling, required or minimum scheduling practices, supply their ESS with a load forecast on a more frequent or regular basis, or even negotiate a structure where the ESS compensates the customer for RIC charges received.

Q. Staff also identifies that "the ESS schedules not by customer, but in aggregate, it is unclear how an individual customer could avoid the RIC even if the ESS correctly scheduled the customer's load, but under forecast a second customer's load."[82] Do you agree?

A. No. Again, Staff's assessment is based on incorrect assumptions. As is generally accepted in the electric industry, megawatts cannot be "color coded" meaning that it is not reasonable to infer that an ESS provided a complete schedule for one customer, but under-scheduled for a second customer when an ESS is submitting an aggregate schedule. AWEC seems to subscribe to a similar notion, "if an ESS serves multiple customers, some might over-schedule while others under-schedule for a given hour."[83]

It is clear from Calpine's testimony that there is no attempt to forecast individual loads at a meaningful level that could be used for more accurate scheduling.[84] This is further

[81] Staff/200, Soldavini/17.
[82] Staff/200, Soldavini/10.
[83] AWEC/100, Mullins/16
[84] Calpine/100, Higgins/10-11.

reinforced by Calpine's responses to Staff data requests 1, 2, and 3[85], where Calpine states that it hedges "customer's estimated power consumption shortly after contract execution. Calpine Solutions then aggregates our entire estimated customer load and makes, over time but well before the delivery month, whole power purchases" indicating that Calpine makes no attempt to use individual customer loads beyond the long-term forecast used for hedging. Calpine goes on to explain that it charges/credits imbalances to its customers as the "hedge > actual usage" indicating that Calpine treats its initial financial hedge as the customer's load forecast.

[85] See PGE Exhibit 212.

VI. Standard Offer Service

Q. Please briefly summarize PGE's proposal as it related to standard offer service?

A. In our opening testimony, we proposed two standard offer service options, the PGE Daily Market Energy Option ("Daily Market Option") and the PGE Long-Term Energy Option ("Long-Term Option"). The Daily Market Option is similar to the existing daily option under LTDA but modified to incorporate additional costs associated with complying with the Oregon Renewable Portfolio Standard (RPS). The Long-Term Option is a new option whereby PGE enters into a resource contract to supply the NLDA customer and passes the costs of such contract, plus a margin and other related costs (e.g. wheeling), directly to the NLDA customer.

Under either option, the amount of RPS related procurement is only that which is needed to comply with the applicable RPS target at the time. Additionally, the RIC and RAD apply to both standard offer options.

Q. Why is PGE proposing a long term standard offer service option in its Schedule 689?

A. In proposing the long term standard offer service option, PGE's objective is to offer a standard offer that is RPS compliant. The current daily market option is a Mid-Columbia daily index purchase which is not RPS compliant. PGE does not have any customers on its daily option that are through the five year transition adjustment which means customers on the daily option are still contributing to PGE generation resources that provide RPS compliance. When these customers have completed their five years of transition adjustments, then the standard offer must be RPS compliant. In contrast, NLDA customers who pay a 20% transition adjustment, will not be fully contributing to RPS compliance, and any standard offer option must meet the RPS. This long term standard offer service was designed with them in mind — to have a standard offer suitable (and legally compliant) for NLDA customers.

Q. What issues do parties raise relating to standard offer service options?

A. Both Calpine and Staff raised issues regarding PGE's two proposed options. Calpine contends that the Long-Term Option constitutes a special contract under the Oregon Administrative Rules (OARs), is not allowed under the NLDA or direct access OARs, and that the standard offer should only "be based on a daily market index price".[86] Staff's primary issue is regarding discrimination due to "otherwise similar customers (such as those on PGE's Schedule 489, Large Nonresidential Cost-of-Service Opt-Out) would not be afforded the same choice, at least in the interim period between Schedule 689 going in to effect and service year 2022"[87] and making changes to the standard offer service options outside of a general rate case.

Q. Does PGE agree with the parties' positions?

A. No. PGE believes that the parties have taken positions that are not supported by the direct access rules and have the potential to place PGE in a position where it is forced to choose between complying with the RPS at the expense of customers and shareholders or failing to comply with Oregon law.

A. Long-Term Option is Within the Direct Access Rules

Q. Do the parties' positions conflict with the direct access rules? If so, how?

[86] Calpine/100, Higgins/33.
[87] Staff/200, Soldavini/16-17.

A. Yes. Calpine suggests that because the Commission did not explicitly allow a service like the Long-Term Energy Option, the Daily Market Option is the only option allowed. This is directly in conflict with the direct access rules.

Q. What rule allows PGE to offer its new standard service Long-Term Energy Option?

A. Non-residential Standard Offer OAR 860-038-0250(1); "…each electric company shall provide one *or more* standard offer rate options to large nonresidential retail electricity consumers…" (emphasis added).

Q. Do the administrative rules require standard offer service to be charged at daily market price?

A. No. OAR 860-038-0250-2(a) states; "A standard offer rate option shall be a tariff approved by the Commission, which is priced based on supply purchases made on a competitive basis from the wholesale market plus the transition credit or transition charge, if any, and all other unbundled costs of providing standard offer service. A standard offer rate must reflect the full costs of providing standard offer service…"

Q. Do the Commission's administrative rules require that standard offer service options be offered only in general rate cases?

A. No.

Q. Is there a market index for RPS products?

A. No. This is the primary reason PGE is proposing the Long-Term Energy Option. OAR 860-038-0250(a) references "supply purchases made on a competitive basis from the wholesale market…" and it is PGE's position that the wholesale market for RPS products is only accessible by direct contracting with the resources capable of supplying these products.

Calpine acknowledges this in its response to PGE's data request 013 where Calpine responds that it "is not aware of any index or indices for Oregon RECs."[88]

B. PGE's Proposal Is Not Discriminatory and Must Comply with the RPS

Q. Are Schedule 689 and Schedule 489 customers significantly different?

A. Yes. As we explained above in our testimony, NLDA and LTDA are different classes of customers. This is a fundamental premise that enabled the NLDA program to exist.

Q. Does PGE intend to modify the LTDA standard offer service options to include the Long-Term Option?

A. Yes. As indicated in PGE's response to Staff Request No 009[89], PGE stated "it is appropriate to have the same standard offering options in both the NLDA and LTDA programs." However, the stipulation in Docket No. UE 338[90] prohibits PGE from making changes to the LTDA program until 2022.

Q. Is the Long-Term Option necessary for LTDA prior to 2022?

A. No. PGE currently only has one long-term opt-out customer who recently began standard offer service and PGE expects to request a change to its tariff prior to the end of that customer's transition period.

Q. Calpine suggests the Long-Term Energy Option is meant to provide preferential treatment over the Daily Market Option. Is this PGE's intent?

A. No. Calpine expresses concern that PGE's proposed Long Term Energy Service Option does not require payment under the return-to-service provisions in OAR 860-038-0720. This is

[88] See PGE Exhibit 213.
[89] See PGE Exhibit 214.
[90] See UE 335 Order No. 19-129, Appendix B, At Page 3.

not PGE's intent. Calpine cites PGE's Schedule 689 advice filing, specifically "If the customer elects to return to the Company's Daily Market Energy Option or cost-of-service based pricing…the Customer making the election will be subject to the Cost-of-Service Return Charge for three years."[91] The language Calpine cites in PGE's advice filing is an error and PGE will seek to correct it before the NLDA program is approved and implemented.

Q. What clarification will PGE make to its cost-of-service return charge in response to Calpine Solutions?

A. PGE will clarify that the three year notice provision and return to service charge applies to all standard offer service options and is consistent with OAR 860-038-0720.

Q. Is Staff's recommendation to delay the decision on PGE's proposal regarding standard offer service options until a GRC harmful?

A. Yes. While Staff "does agree with PGE that if it must procure RECs for a customer to comply with Oregon RPS, the customer should be allocated those costs, and that the inclusion of such charges appears reasonable"[92], Staff recommends delaying any inclusion until PGE's next general rate case. By doing so, Staff is requiring that PGE COS customers to bear the costs of complying with Oregon law (SB 1547) for an unknown period of time without an ability to recover such costs from NLDA customers. This proposal is again another clear instance of cost shifting to COS customers. Additionally, as we discussed above, the purpose of docket UE 358 is to evaluate and implement PGE's NLDA filing. The

[91] PGE's Advice No. 19-02, At Page 8.
[92] Staff/200, Soldavini/25.

Commission can certainly make a determination within UE 358 and allow the inclusion of RPS related costs prior to a general rate case.

C. The Long-Term Energy Option is Not a Special Contract

Q. Is the Long-Term Energy Option a special contracting that allows PGE to sell a "specialized energy product with unique pricing to each individual customer"[93]?

A. No. Calpine contends that the Long-Term Energy Option is a special contract because it is "a proposal for PGE to provide generation supply in accordance with individually negotiated prices...."[94] This is not the case. As we detailed in our testimony, the Long-Term Energy Option is designed to allow PGE to comply with the Oregon RPS requirements by accessing the wholesale market for RPS products, which are not index based. Our proposal does not allow PGE to negotiate rates with customers or create specialized products as Calpine implies.

Q. What is the pricing basis for the Long-Term Energy Option?

A. As proposed by PGE, the rate for the Long-Term Energy Option is based on supply purchases made on a competitive basis, any incremental costs associated with providing the option (e.g. wheeling and ancillary services), does not include any avoided costs, allows for the inclusion of administrative costs. Pricing will include all criteria identified in OAR 860-038-0250 and ensure no shifting of costs between NLDA and cost-of-service customers.

Q. Does the Long-Term Energy Option result in cross subsidization or give PGE the ability to exercise a competitive advantage?

[93] Higgins 23-24
[94] Higgins 25

A. No. As we stated in our testimony, both the RIC and the RAD apply to customers electing the Long-Term Energy Option, ensuring that no cross subsidization occurs for providing reliability. Additionally, the Long-Term Energy Option is a cost-based product, not a negotiated rate, and specifically includes costs associated with any and all additional services required to delivery such a product to the customer.

Despite what Calpine suggests in its testimony, PGE has and will continue to comply with the Commission's Code of Conduct rules. Additionally, the Commission already possesses the appropriate oversight to ensure that none of the violations Calpine articulates it its testimony will occur. However, should the Commission share Calpine's concerns, PGE proposes the Commission instruct PGE to add reporting requirements to add transparency to PGE's Long-Term Energy Option offering. should any NLDA customers elect the option

IV. NLDA Cap and Queue Implementation Considerations

A. Nature of PGE's NLDA Program Cap

Q. Why is PGE discussing the cap?

A. PGE is discussing the cap because it is key to administering the program and protecting nonparticipating customers, and parties have raised issues about the cap in their reply testimony. Staff and AWEC suggests the cap is a "soft cap."[95] Staff opines that because the Commission said it would entertain customer waiver requests to the cap for good cause, the cap is "soft." Calpine Solutions expressed interest in greater transparency into how progress toward the cap is measured as well as the commitment required for a customer to secure space for their load.

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[95] AWEC/100, Mullins/3.

Q. Does PGE consider the 119 MWa to be a hard cap?

A. Yes. While the Commission adopted each utility's program cap in its order and declined to place it in the administrative rules, PGE considers its 119 MWa cap a hard cap and will manage enrollments accordingly. This is particularly important given issues of unwarranted cost shifting as COS supply customers bear the costs of reliability and resource adequacy for these loads, given that PGE is not planning for these loads. Treating the 119 MWa as a hard cap allows ample customer participation while containing the degree of cost shifting per the requirements of SB 1149.[96] The imposition and size of the cap is intended to mitigate issues that may arise around cost-shifting, reliability, or other as-yet unknown risks.

Q. Is this interpretation consistent with the Commission's record in the NLDA rulemaking?

A. Yes. In the AR 614 proceeding, Staff originally proposed a cap of 12%[97] of 2017 weather adjusted load. However, at the AR 614 New Load Direct Access Rulemaking public meeting, Commissioners recognized the need to reduce the proposed cap from 12% to 6% of weather normalized 2017 annual load. Chair Decker said; "the small cap allows some time and space to allow issues to emerge within the larger context."[98] CUB agreed "it is important to be conservative in its roll out to protect existing COS customers. Decreasing the cap size from 12 percent to 6 percent helps achieve this."[99] In Staff's final AR 614 comments, "Staff agree[d] that limiting the size of the NLDA program to 6 percent of the

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[96] Section 8(1) of SB 1149 Enrolled, states that the provision of direct access to some retail electricity consumers must not cause the unwarranted shifting of costs to other retail electricity consumers of the electric company. See Chapter 865 Oregon Laws 1999 Section 8(1).
[97] AR 614 May 22 Public Meeting Memo, submitted May 17, 2018, Attachment 1 at 3
[98] Oral comments at Commission Public Meeting 7-7-18 – AR 614 New Load Direct Access Rulemaking.
[99] CUB comments in AR 614 dated August 1, 2018 p.4

utility's calendar year 2017 load appropriately balances risk and opportunity for this program."[100] In Order 18-341, Commission states:

> Part of our justification for limiting the size of this program is the reality that COS customers are increasingly relied upon to finance system improvements that impose near-term costs to adapt the system to new utility and customer-sited technology intended to lead to long-term economic and environmental benefits for all customers. Such is the case with demand response, storage initiatives, electric vehicles, and other programing.[101]

Since the intent of the cap was to mitigate these risks, and since PGE's participation queue currently contains multiples of the cap amount[102], we must proceed with caution to avoid unintended consequences related to this program and consider the cap a hard cap.

Q. Staff notes that PGE does not acknowledge the Commission's statements around a waiver of the cap if a customer has good cause. How does PGE respond?

A. PGE acknowledges that the Commission established a waiver process. However, that option is for the customer to pursue if the circumstances are warranted.

Q. What does PGE mean by a hard cap? What are the implications?

A. A hard cap is the absolute upper limit of the amount of load that can participate in NLDA. This is contrasted with a soft cap, which may be more flexible and could be exceeded. In adopting caps, the Commission acknowledged that the caps would be treated as hard caps by the utilities, anticipating a Commission waiver process for aggrieved customers with good cause. See Order 18-341 at page 7. The implications for PGE's NLDA program and customer participation are that if a customer seeks to participate but its forecasted load (as defined in the Commission's rules) exceeds available room under the cap, the customer will be deemed ineligible.

[100] Staff final comments in AR 614, dated August 1, 2018.
[101] OPUC Order No. 18-341, At Pages 7-8.
[102] See PGE Exhibit 215.

Q. Please describe how PGE will determine, assuming all other eligibility requirements are met, whether a customer's forecasted load fits under the cap. What will PGE use to determine a customer's forecasted load?

A. To identify a customer's expected NLDA load, PGE will use the load information provided by the customer to PGE that establishes the basis for distribution facilities to meet that customer's load. PGE expects the new load customer will come to PGE with its anticipated new load or load growth and desire to plan distribution facilities to meet its anticipated load. To prevent the customer from using different load forecasts for NLDA eligibility and distribution facility design, PGE will use the customer's planned distribution facilities information as the forecasted load for NLDA. This would be memorialized in the written binding agreement referred to in OAR 860-038-0740.

PGE's practice would prevent a customer from requesting design of distribution facilities for 10 MWa but requesting 20 MWa for NLDA eligibility, or vice versa. In discussions with the customer, there must be one forecasted load for distribution facilities and NLDA eligibility. For example, if the customer requests distribution facilities necessary to serve a multi-phase 100 MWa load operation behind one meter (with a signed binding agreement) but only 30 MWa of availability remains under the cap, PGE would deny program participation.

Q. Why does PGE plan to use the customer's forecasted loads for the first 60 months to measure against the NLDA cap?

A. Commission rules do not prescribe how customer load should be counted toward eligibility under the cap, nor how the company should administer the cap. Thus, PGE identifies this as an area to exercise discretion, given operational, program, and other considerations. In

PGE's experience with large customer load expansions and new facility builds, customers and facilities have long ramp periods over which the facilities' loads will continue to grow. In fact, this is anticipated in the Commission's NLDA rules that allow a customer to reach the required minimum of 10 MW over a 36-month period.[103] Given that longer lead time, it is reasonable to provide customers the opportunity to ensure their total amount of expected load over the 5 year/60-month transition period fits within the NLDA cap.

Q. Staff questions how PGE would respond if a customer's plans are tentative or load growth is not realized. How do you respond?

A. It is unlikely the customer is going to pay its share of distribution facilities to meet its load projections if that load is unlikely to come to fruition or is tentative. In PGE's experience, when customers are presented with their share of the bill for distribution facilities, they sharpen pencils to more precisely forecast what they will need. If, however, customer load growth does not come to fruition and they do not meet the 10 MWa for participation, then Commission rules direct they be unenrolled after 3 years.[104] If the customer qualifies but does not meet its forecast at 60 months, then capacity is freed up under the cap and made available to customers in the queue.

Q. Staff proposes that if a customer enrolls in NLDA and then expands so that their total usage at a single meter is above the cap, then the customer must apply for a Commission waiver. Does PGE agree?

A. Our proposed NLDA eligibility design should generally prevent customers from expanding or growing through the NLDA cap. Because the load forecast used for NLDA eligibility

[103] OAR 860-038-0710(2)b.
[104] OAR 860-038-0750.

and the same load forecast used to design the limits of the distribution facilities, customers will not be able to expand through the NLDA cap without also expanding the distribution facility design. Should a customer grow through the distribution facility design capacity then PGE agrees that load growth beyond what is available under the cap would require Commission waiver. Unless load forecast are tied to distribution facilities planning, customers will be incentivized to game the program by understating forecasted loads, and place the Commission in an untenable position to either grant the waiver to allow continued NLDA participation beyond the cap, or have to unenroll the customer (with all attendant consequences given that the customer would have signed a contract, budgeted for the energy cost of NLDA, etc.). To prevent gaming and for consistency in planning and forecasting, the best approach is to use the customer's forecasted NLDA load for purposes of distribution planning, again, presuming the load is behind one meter and the customer otherwise meets program rules.

Q. If a customer participating in NLDA program has load growth behind their participating service point ID (meter), would the full load be included in the program?

A. Yes, if their full load doesn't exceed the 119MWa cap. If their load growth is such that the cap is exceeded, we agree with Staff that the customer must seek a waiver for their full load.[105] The customer would remain in the queue pending the decision on the waiver.

Q. If a customer participating in NLDA program has load growth that requires a new service point ID (meter) will the new service point ID (meter) be included in the program?

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[105] Staff/100, Gibbens/23.

A. Not automatically. If the load of the new service point ID fits within the 119 MWa cap then the customer must follow the standard NLDA process including qualifying the load, notification provisions and complete a new binding written agreement for the new load. If the load of the new service point ID does not fit within the cap, it will not be included in the NLDA program.

Q. Calpine objects to including load served under PGE's proposed Long-Term Energy Option under the 119 MWa NLDA program cap. Please respond.

A. PGE disagrees and asserts that the proposed Long-Term Energy Option, as well as any other standard offer service should be included under the cap. This is consistent with management of the cap for PGE's Long-Term COS Opt-Out[106] program where the load of both customers served by an ESS and customers served at PGE Daily Market Price count toward the cap. PGE's Long-Term Energy Option is a nonresidential standard offer under OAR 860-038-0250, which states; "each electric company shall provide one or more standard offer rate options to large nonresidential retail electricity consumers[107]…which is priced based on supply purchases made on a competitive basis from the wholesale market…[108]" Nonresidential standard offers are alternatives available to customers served by direct access per Default Supply OAR 860-038-0280 (1-2); "Default supply is an alternative available to nonresidential consumers served by direct access. 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."

[106] Commonly referred to as the Long Term Direct Access (LTDA) program.
[107] OAR 860-038-0250 (1).
[108] OAR 860-038-0250 (2)a.

B. NLDA Non-binding Queue Implementation/Enrollment

Q. Please refresh the understanding of customers in the queue. How many customers and what is the total load of interested customers?

A. Six customers with total load between 250 MWa and 612 MWa.

Q. For any customers in the queue, has PGE offered any responses to customers opining on their eligibility?

A. No. There may be customers in the queue that are not eligible but at this stage in the process, PGE took all customer notifications of interest. In response to each customer notification, PGE sent an automatic email reply as follows:

> You have submitted a revocable notice to enroll in PGE's New Load Direct Access program. That program would be based on the tariff filing we made in Advice 19-02, as approved by the Oregon Public Utility Commission (PUC). The PUC has directed an investigation of the tariff filing for a period not to exceed nine months. That proceeding is underway and docketed as UE 358. For further information, please contact Scott Gibbens, Senior Economist at the PUC at 503-378-6688 or scott.gibbens@state.or.us.

Subsequent to this we filed a letter with the Commission and sent emails informing each customer of their place in the queue and the approximate amount of load ahead of them in the queue.[109]

Q. What do the administrative rules state regarding early and binding notification?

A. Oregon Administrative Rule 860-038-0740 states:

> (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 COS rates at the earlier of either:
>
> (a) A binding written agreement with the utility for eligible new load, or

[109] See PGE Exhibit 215.

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

Q. AWEC and Calpine both propose that the Commission not apply a strict application of the rules to customers in the queue. Does PGE agree?

A. No. AWEC proposes to allow all customers in the queue to participate subject to the cap and Calpine proposes to relax the one-year notice rule such that the one-year notice rule does not bar the customer's participation provided the customer committed to service between the time the Commission's NLDA rules were adopted and the conclusion of this UE 358 docket. The one-year notice rule provides that the customer must give notice of NLDA one year prior to meter energization or a written binding agreement.[110] PGE proposes to use the date customer entered the non-binding participation queue as the notice date so they may energize their operations no earlier than one year from that date.

Q. Staff questions whether PGE's calculation of the participation cap serves to unnecessarily curtail participation in the NLDA program suggesting that PGE is proposing to include all future anticipated expansions from a customer in calculating room under the cap. Is PGE managing the cap this way?

A. No. If a customer's forecasted load behind one meter includes expanded facilities and it is the same as is in the binding agreement for distribution facilities, then that load will be the queued amount of load for that customer, presuming the customer meets other eligibility requirements. Generally, this will include only the facilities required for the first five years of the new load.

Q. Staff also questions the process if a customer leaves the queue and wishes to pursue some other PGE service option and how that would work. Please respond.

[110] OAR 860-038-0740(1) (a – b).

A. PGE has not defined a specific process for a customer to leave the NLDA queue; however, to the extent a customer has signed up for another PGE program that is not compatible with NLDA, or if the customer has energized their site, they will be removed from the queue. PGE agrees with Staff's characterization that "...PGE's currently approved tariff provisions would continue to govern the timing and rate requirements for such a customer.[111]"

Q. Staff proposes that PGE hold a place in the queue for a customer determined to have forecasted load exceeding the amount available under the cap, while the customer seeks a waiver. Does PGE agree.

A. Yes.

Q. Please explain whether the following statement from PGE's opening testimony encompasses construction power: "If a customer energizes their site prior to the effective date of Sch 689, they cannot participate in sch 689".

A. As PGE stated in response to Calpine DR013, the statement regarding energization prior to the effective date of Schedule 689 is not intended to include construction power before normal operations of the new load facility itself. The energization date is the date of start-up of operations. Standard operating procedure for electric service during construction at any site is that a temporary meter is installed on the site in the developer and/or the contractor's name, to be used prior to and during construction. Since the usage and demand at the temporary meter is generally low, usually rate schedule 32 or 83, it will be served at a cost-of-service rate. Once construction is complete, the temporary meter is removed, and the facility is transferred to the customer under the customer's name as the owner/operator.

[111] Staff/100 Gibbens/26.

This is the point that the customer's facility is considered energized for purposes of taking service under rate schedule 689.

Q. If a customer energizes their site prior to Schedule 689's effective date, are they eligible to participate in NLDA?

A. No. If the temporary construction meter is removed and the facility is transferred to the customer under the customer's name as the owner/operator prior to the effective date of Schedule 689, the customer will not be eligible for the NLDA program. ORS 757.205 requires PGE to file rate schedules with the Commission that must be in force at the time service is performed in connection with it; consequently, PGE is not authorized to make the offering of Schedule 689 available to customers until there is an approved tariff.

Q. Calpine suggests that because of delay in the PGE NLDA program starting, the Commission should be flexible in accommodating customer interest. Does PGE agree?

A. No. PGE takes issue with Calpine's characterization. Nothing in OPUC Order 18-341, or in the OARs, directed a deadline by which PGE must make NLDA service available to customers. PGE submitted a comprehensive tariff filing demonstrating that PGE gave considerable time and attention to topics such as the RIC and the RAD, which are intended to help assure continued system reliability, with benefits, costs, and risks fairly shared by all customers so that there is no unwarranted cost or risk shifting.

Moreover, the Commission clearly acknowledged that certain matters should not be dictated by rule but left to the electric utility to be determined in its tariff. An example of this can be found on page 6 of Order 18-341, in the context of movement of an NLDA participant to COS rates, to default supply, or to alternative supply. Accordingly, PGE has determined that those and several additional provisions are appropriate for inclusion in its proposed tariff. But, until the tariff is approved, PGE can only speculate as to whether such provisions will be accepted and as to what rates and charges the Commission may deem appropriate and applicable to PGE's offering. Such information is also critical to the development of a service agreement between PGE and NLDA customers. As a result, the terms and conditions of a service agreement, that, by rule[112] must be executed by the utility and NLDA customer to enroll in the NLDA program, would be speculative, in the absence of an approved tariff.

Q. Regarding NLDA program enrollment, does PGE agree with Calpine's suggestion that PGE's NLDA program should "…allow for some amount of start-up activity at the newly constructed facility which may take service under cost-of-service rates before the new large load is committed during the long term for service under the NLDA program"[113]?

A. No. PGE has already allowed for construction power as described above. As noted, the customer's facility is considered energized for purposes of taking service under schedule 689 once construction is complete, the temporary meter is removed, and the facility is transferred to the customer under the customer's name as the owner/operator. Schedule 689, following the Commission's rules, allows for a ramp up period by providing a period of 36 months for the customer to achieve 12 or more consecutive months at 10MWa or larger. During the Commission's rulemaking process, 36-months was the agreed upon period for the purpose of allowing a customer time to ramp up operations to meet the 10 MWa size threshold for this program. Allowing more time between construction completion and

[112] OAR 860-038-740(1)(a).
[113] Calpine/100, Higgins/38.

operations, for example, a ramp up to 1MWa, would materially change the agreed upon time period in rule.

Q. How is the cap managed if a Customer fails to reach the 10 MWa threshold and is ultimately deemed ineligible to participate in the NLDA program.

A. The room under the cap that had been held for that customer would be freed up for other customers to participate.

Q. What will PGE do if the customer signs a binding written agreement for some amount to hold a place under the cap and then, when detailed designs are undertaken for distribution services, the customer lessens the load forecast?

A. If room was created under the cap, we would reach out to the next customer in the NLDA participation queue.

Q. PGE has represented that there is more load in the participation queue than is available under the cap, how will you administer the binding written agreements?

A. At the time Schedule 689 is approved by the Commission we will review the participation queue and remove those customers whose facilities have already been energized. We will then review the remaining customers and provide binding written agreements to those eligible customers whose load fits under the cap. Should any of these customers not return a signed agreement within 10 business days, they will forfeit their spot in the queue, and we will proceed to the next customer on the list.

Q. Calpine asserted that the binding written agreement be reviewed and approved in this proceeding. Please respond.

A. PGE disagrees that this contract merits Commission approval; however, as with all its operational documents, PGE has no objection to Staff or Commission review. As stated in our response to Calpine's DR 14; "PGE does not intend for the NLDA form contract agreement to be approved by the Commission. Similar to PGE's LTDA contract, the NLDA contract will implement the requirements for service per the terms and conditions of the applicable schedule(s), once approved, and PGE's tariff rules.[114]" Although the Long-Term Cost-of-Service Opt-Out agreement has not been approved by the Commission, it is reviewed annually by our Legal department and the DA program manager and is edited to reflect the experiences we've gained working with LTDA customers to address their changing needs and those of PGE, due to things like relocations, growth, and sales of facilities, to name a few. In short, our agreement has evolved to reflect the evolution of the program and our need to adapt in order to accommodate changing needs and still uphold the letter and the spirit of the rules, law, Orders of the Commission, etc.

[114] See PGE Exhibit 216.

V. Conclusion

Q. Please briefly summarize PGE's key points in reply.

A. PGE supports suspending PGE's NLDA program implementation to allow for a general investigation into direct access and resource adequacy policy to consider the responsibilities of direct access customers to contribute to reliability and resource adequacy costs. Our support is contingent on the NLDA program being held in abeyance pending the resolution of whether PGE should plan for NLDA loads, acquire capacity for those loads and charge the costs to NLDA customers, as well as the RIC-- charging for reliability resources paid by cost of service customers to NLDA customers. PGE would suggest that standard offer service options for NLDA customers also be included in a separate investigation. So that interested NLDA customers are not prejudiced by the extension of time needed for this investigation, PGE would support a waiver of the Commission's one year notice rule to allow otherwise eligible customers who fit under the program cap, to participate. PGE offers this interim solution, even given the paramount importance of resource adequacy and fundamental fairness and equity to cost of service customers.

Q. Should the Commission prefer not to further suspend PGE's NLDA program implementation, what do you recommend?

A. We support Staff's alternative recommendation with clarifications. Parties agree that a future investigation is warranted to consider direct access policy generally. At that time, the need for all direct access customers to make RIC and RAD capacity payments can be reconsidered. Until that time, NLDA customers should be required to make RIC and RAD capacity payments with the opportunity to fully or partially offset the RAD payments by electing to participate in voluntary curtailment as administered by PGE's demand response program.

Q. Does that conclude your testimony?

A. Yes.

I. List of Exhibits

PGE Exhibit	Description
201	PGE Data Request 002 to AWEC
202	PGE Data Request 004 to AWEC
203	PGE Data Request 006 to AWEC
204	PGE Data Request 006 to Calpine
205C	PGE Data Request 002 to Calpine
206	PGE Data Request 003 to Calpine
207	PGE Data Request 004 to Calpine
208	PGE Data Request 005 to Calpine
209	PGE Reply to AWEC DR 018
210	PGE Reply to OPUC DR 003
211	PGE Reply to AWEC DR 010
212	Calpine Reply to OPUC DR 001-003
213	PGE Reply to OPUC DR 013
214	PGE Reply to OPUC DR 009
215	PGE Customer Queue Letter
216	PGE Reply to Calpine DR 014

PGE DATA REQUEST NO. 2 TO AWEC:

Does AWEC agree that the ability for PGE to purchase energy in wholesale markets is limited by a counterparty's willingness to sell and is fundamentally limited by the availability of regional generating resources and associated fuel? Does AWEC agree the ability for PGE to access regional electricity markets is most limited during periods of high regional demand?

RESPONSE TO PGE DATA REQUEST NO. 2:

AWEC objects to this request on the grounds that it is vague and not relevant to the issues in this proceeding. Notwithstanding this objection, AWEC does not necessarily agree the ability for PGE to access regional electricity markets is most limited during periods of high regional demand. Regional electricity markets, such as the bilateral market or energy imbalance market, are accessible to PGE even in periods of high regional demand. High regional demand might put upward pressure on market prices, but that does not limit PGE's ability to access the market.

PGE DATA REQUEST NO. 4 TO AWEC:

Refer to AWEC/100 at 7:

And from a regional perspective, PGE's direct access load is insignificant. Compared to current regional load of over 20,000 aMW, even if PGE maxed out both its LTDA and NLDA programs, that load would amount to just 2% of the region's load. There is simply no way that the type of energy product direct access customers purchase from their ESS could meaningfully contribute to a reliability event requiring PGE to implement its Curtailment Plan.

a) Does AWEC contend that direct access load does not affect the region's resource adequacy? Please explain.
b) Does AWEC contend that direct access load should not contribute to support resource adequacy? Please explain.
c) Does AWEC believe that the size of PGE's COS load is large enough to affect the region's resource adequacy?
d) If the response is Yes to (c), does AWEC believe that PGE should maintain access to physical capacity resources to support the resource adequacy needs associated with COS load? Please explain.

RESPONSE TO PGE DATA REQUEST NO. 4:

AWEC objects to this request on the grounds that it is vague and not relevant to the issues in this proceeding. Notwithstanding this objection, AWEC responds as follows:

a. Please refer to AWEC's response to PGE data request 3

b. No, AWEC has not made such a contention. Direct Access customers must acquire firm power to serve their loads, and thus, do support resource adequacy.

c. Yes.

d. AWEC believes that PGE must conform with relevant NERC, FERC, and OPUC requirements regarding resource adequacy. AWEC is aware of no specific requirement for PGE to maintain access to incremental physical capacity resources, above and beyond those necessary to satisfy NERC, FERC, or OPUC requirements, to support the resource adequacy needs associated with COS load.

Date: August 2, 2019
Respondent: Bradley G. Mullins (503-954-2852)
Witness: Bradley G. Mullins

PGE DATA REQUEST NO. 6 TO AWEC:

Refer to AWEC/100 at 8:

a) Does AWEC agree that under current direct access policy both COS and direct access customers share in the risks associated with curtailment by PGE due to a lack of supply? Please explain.

b) Does AWEC agree that COS customers currently contribute toward PGE's cost of carrying capacity necessary to support resource adequacy? Please explain.

c) Does AWEC agree that ESS customers currently do not contribute toward PGE's cost of carrying capacity necessary to support resource adequacy? Please explain.

RESPONSE TO PGE DATA REQUEST NO. 6:

AWEC objects to this request on the grounds that it is vague and not relevant to the issues in this proceeding. Notwithstanding this objection, AWEC responds as follows:

a. AWEC interprets the phrase "share in the risks associated with curtailment" to mean that PGE must curtail both COS and direct access customers in a nondiscriminatory manner during a reliability event. With this understanding, AWEC agrees that COS and direct access customers share this risk, but disagrees that this is due to "current direct access policy." Rather, this is due primarily to NERC reliability standards and PGE's role as the Balancing Area Authority.

b. AWEC agrees that COS customers currently contribute toward PGE's cost of carrying capacity necessary to support resource adequacy for the COS customers loads.

c. AWEC agrees that ESS customers currently do not contribute toward PGE's cost of carrying capacity necessary to support resource adequacy **for COS customers' loads**, except during the transition period. ESS customers purchase and contribute their own resource adequacy, but the capacity purchased by ESS customers is not used to support resource adequacy for PGE's COS customers – it is used to support the direct access customer. As explained in AWEC/100, direct access customers pay for both energy and capacity PGE uses for their benefit through both energy imbalance and ancillary services charges under the OATT. Furthermore, direct access customers support their own resource adequacy through enforceable contracts with their ESSs for firm power to meet their loads.

Date: August 2, 2019
Respondent: Bradley G. Mullins (503-954-2852)
Witness: Bradley G. Mullins

Portland General Electric Data Request No. 06:

Please identify all resource supply agreements in effect as of January 1, 2018 with a contract term of five years or greater. For each contract identify:

a. MW quantity of the contract

b. Term of the contract

c. The effective date and the termination date of the contract

d. The physical resource(s) supporting the contract

e. The resupply provisions associated with the contract (ex. Unit contingent, physical replacement, financial damages, non-firm)

f. Point of delivery

g. If applicable, long-term transmission rights used to deliver the resource to PGE's system including Assignment Reference (ARef) numbers

h. For the resources/contracts identified in this request, please provide the NERC electronic tag (e-tag) numbers and copies of the e-tags active during and including August 6th through and including August 10th, 2018.

Calpine Energy Solutions, LLC's Response:

Calpine Energy Solutions, LLC does not have any power supply agreements in effect as of January 1, 2018 with a term of five-years or greater.

Portland General Electric Data Request No. 02:

Provide the total monthly Oregon Direct Access customer load served by Calpine Energy Solutions, LLC in 2018.

Calpine Energy Solutions, LLC's Response:

2018	PGE KWh
Jan	[redacted]
Feb	[redacted]
Mar	[redacted]
Apr	[redacted]
May	[redacted]
Jun	[redacted]
Jul	[redacted]
Aug	[redacted]
Sep	[redacted]
Oct	[redacted]
Nov	[redacted]
Dec	[redacted]
Totals	[redacted]

Portland General Electric Data Request No. 03:

Identify the total volume of 2018 energy purchases made by or on behalf of Calpine Energy Solutions, LLC, to meet its PGE direct access loads purchased in the Day-Ahead Northwest bilateral market.

Calpine Energy Solutions, LLC's Response:

In 2018, Calpine Energy Solutions, LLC ("Calpine Solutions") had no purchases of power in the Day-Ahead Northwest bilateral market.

Calpine Solutions current practice is to financially hedge its customers' contracted volumes that have market price exposure shortly after contract execution. Calpine Solutions then aggregates our entire estimated customer load and makes, over time but well before the delivery month, wholesale physical power purchases. These wholesale physical power purchases are contracts for firm power deliveries, with liquidated damages penalties for non-performance ("EEI firm LD"). The Federal Energy Regulatory Commission has determined that power purchase agreements containing the EEI firm LD provisions "are sufficiently firm to make those agreements eligible for designation as a network resource." Order No. 890-A, 121 FERC ¶ 61,297, at P 832 (Dec. 28, 2007).

By the delivery date, all power purchases Calpine Solutions has previously made are aggregated to a single, hourly amount for the entire pool of customer load associated with Calpine Solutions for that day for that hour.

Portland General Electric Data Request No. 04:

Identify the total volume of 2018 energy purchases made by or on behalf of Calpine Energy Solutions, LLC, to meet its PGE direct access loads purchased in the Hour-Ahead Northwest bilateral market.

Calpine Energy Solutions, LLC's Response:

In 2018, Calpine Energy Solutions, LLC had no purchases of power in the Hour-Ahead Northwest bilateral market. Please see the Response to Portland General Electric Company's Data Request No. 03 for additional information.

Portland General Electric Data Request No. 05:

Identify the total volume of 2018 energy purchases made by or on behalf of Calpine Energy Solutions, LLC, to meet its PGE direct access loads purchased from the California Independent System Operator (CAISO).

Calpine Energy Solutions, LLC's Response:

In 2018, Calpine Energy Solutions, LLC ("Calpine Solutions") had no purchases of power directly from the California System Operator ("CAISO") balancing authority. However, Calpine Solutions is aware that a small percentage of purchased power deliveries had, as their source, the CAISO in August of 2018. These CAISO-sourced power deliveries are associated with a title chain, also commonly referred to as a market path, as part of purchases by Calpine Solutions from a non-source specific Firm, Liquidated Damages product at the Point of Delivery entered into before the delivery month.

Please see the Response to Portland General Electric Company's Data Request No. 03 for additional information.

June 28, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Karla Wenzel
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UE 358
PGE Response to AWEC Data Request No. 018
Dated June 17, 2019

Request:

If the Commission authorized it, would PGE have the operational capability to curtail a direct access customer that returns to PGE on an emergency basis without curtailing any cost-of-service customers?

a. **If PGE's answer to the above question is "no," please explain with specificity what PGE would need to do, and/or what investments it would need to make, to obtain this operational capability.**
b. **To the extent PGE's answer to subpart a. differs depending on the customer, please identify the actions that would need to be taken for a: (1) Schedule 485 secondary customer; (2) Schedule 485 primary customer; (3) Schedule 489 secondary customer; (4) Schedule 489 primary customer; (5) Schedule 489 subtransmission customer; and (6) Schedule 689 NLDA customer.**
c. **Please provide an estimate of all costs identified in your answers to subparts a. and b.**

Response:

PGE objects to this request on the basis that it is overly broad and unduly burdensome and requests a detailed technical analysis that PGE has not performed at this time. Without waiving these objections, PGE responds as follows:

The operational ability to disconnect a customer is dependent multiple factors, including, but not limited to the customer's equipment and its configuration, the interconnection into PGE's distribution system and associated equipment, the service voltage level, etc.

PGE's ability to curtail service for specific customers can consistently be operationalized through a customer's participation in a direct load control demand response program.

PGE notes that the RIC and the RAD are not designed to address only the situation where the potential New Load Direct Access (NLDA) customer returns to PGE on an "emergency basis", but instead designed to enable PGE to perform its reliability provider obligation by ensuring resource adequacy and generation reliability without unnecessarily shifting risk and costs to cost-of-service customers.

July 10, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UE 358
PGE Response to OPUC Data Request No. 003
Dated June 26, 2019

Request:

Does PGE agree with the following statement? Once PGE has assessed a RAD charge to an NLDA customer, the necessary capacity to serve that customer exists, including in the event that the ESS has under scheduled its load? If yes, why would an additional charge, the RIC, be necessary and not duplicative? If the Company does not agree with the above statement, why? What is the nature of the capacity acquired by the RIC that makes both charges necessary?

Response:

PGE does not agree with the statement "Once PGE has assessed a RAD charge to an NLDA customer, the necessary capacity to serve that customers exists, including in the event that the ESS has under scheduled its load."

Following the approval of PGE's proposed RIC charge and NLDA tariff, PGE will recover from NLDA customers the costs of providing capacity to balance under-scheduling practices that result in PGE provision of capacity that is not being paid for by the benefitting NLDA customer. Providing the RIC service to NLDA customers is not expected to create a need for additional peaking capacity beyond what is required to provide resource adequacy related RAD service for the same customer. However, providing RIC service will require that PGE make sufficient flexible capacity available in the operational timeframe to balance ESS under-scheduling practices. Importantly, capacity procured for meeting peaking resource adequacy needs (e.g. day-ahead capacity product) may or may not be capable of supporting RIC related service.

The RAD is an unavoidable charge related to the procurement of capacity resources to ensure resource adequacy and meet PGE's peak resource need conditions. The capacity resources procured for RAD service may or may not be capable of balancing ESSs' under-scheduling and providing RIC service. As revenues from the RIC are credited toward all customers through the crediting of PGE's production revenue requirement the RIC charge does not double recover, but instead compensates all customers for the use of capable capacity to meet ESSs balancing needs. Furthermore, the RIC charge is avoidable. If an ESS does not under-schedule within a month, no RIC service will be assessed, and as scheduling practices improve PGE will require less capacity be available in the operational time frame resulting in decreased RIC related costs.

Both the RIC and RAD follow general rate making principles in assigning the costs to the customers which impose those costs onto PGE's system (i.e. cost causation). In order to fully recover the costs imposed by NLDA, both the RIC and RAD charges are necessary and serve to prevent cost shifting to COS customers.

Please refer to PGE's Response to Calpine Request No. 018 for additional details.

June 28, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Karla Wenzel
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UE 358
PGE Response to AWEC Data Request No. 010
Dated June 17, 2019

Request:

Does PGE agree that the RIC would incentivize ESSs to over-schedule since the RIC is only assessed if an ESS under-schedules? If not, please explain why not.

Response:

No. The proposed RIC does not compensate ESSs for over-scheduling. Additionally, an ESS would not be incentivized to intentionally over-schedule for several reasons. Over-scheduling will require the ESS to procure excess energy at an additional cost. Over-scheduling will also expose an ESS to the price difference between the energy index specified under OATT Schedule 4R (e.g. locational marginal price) and the price at which the ESS procured the energy (e.g. day-ahead block energy purchase price).

Staff Data Request No. 01:

Please explain the process by which Calpine reports its scheduled load to PGE. Please include the level of granularity in scheduling. For example, is load scheduled at the customer level, or at the aggregate ESS level?

Calpine Energy Solutions, LLC's Response:

In accordance with WECC day-ahead prescheduling timeline and Portland General Electric Company's ("Portland General") specific scheduling directions, Calpine Energy Solutions, LLC ("Calpine Solutions") provides to Portland General a twenty-four hourly schedule of firm liquidated damages (WECC Schedule C) power deliveries.

Calpine Solutions hedges our customer's estimated power consumption shortly after contract execution. Calpine Solutions then aggregates our entire estimated customer load and makes, over time but well before the delivery month, wholesale power purchases. By the delivery date, all power purchases Calpine has previously made are aggregated to a single, hourly amount for the entire pool of customer load associated with Calpine Solutions for that day for that hour.

Staff Data Request No. 02:

Does Calpine realize any benefits, monetarily or otherwise, if it overschedules load? Please quantify and provide any evidence if applicable.

Calpine Energy Solutions, LLC's Response:

No, when Calpine Solutions' hourly power schedule results in a positive imbalance, Calpine Solutions passes through to the customers that created the positive hourly imbalance (i.e. hedge > actual usage) all the credit revenues (i.e. benefits) received from PGE associated with PGE's Schedule 4R Imbalance Service.

Staff Data Request No. 03:

Does Calpine realize any costs, monetarily or otherwise, if it under schedules load? Please quantify and provide any evidence if applicable.

Calpine Energy Solutions, LLC's Response:

No, when Calpine Solutions' hourly power schedule results in a negative imbalance, Calpine Solutions passes through to the customers that created the negative hourly imbalance (i.e. hedge < actual usage) all the charges (i.e. costs) levied by PGE associated with PGE's Schedule 4R Imbalance Service.

July 12, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UE 358
PGE Response to OPUC Data Request No. 013
Dated June 28, 2019

Request:

In light of the analysis or lack of analysis performed as described in Staff DR 12, has PGE defined the duration of delivery and type of capacity product which would sufficiently mitigate the risk to COS customers? Please provide the type and duration of capacity product PGE will seek via the RAD.

Response:

If directed to plan and procure, PGE would seek to acquire long-term products with a term that's consistent with PGE's long-term planning horizon (e.g. no less than five years). These products would need to be backed by a physical resource, resources, or a system of resources. PGE would be seeking peaking capacity capable of being called on to serve NLDA load as needed. This would likely be targeted toward the day-ahead time frame. Ultimately, the characteristics as well as terms and conditions of the product would be subject to the design criteria of a Request for Proposals (RFP) and the offers received in such RFP.

July 10, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UE 358
PGE Response to OPUC Data Request No. 009
Dated June 26, 2019

Request:

In reference to PGE's Long-Term Energy Option, why does PGE believe that it is appropriate to have a different standard offer for its NLDA and LTDA programs?

Response:

PGE believes it is appropriate to have the same standard offering options in both the NLDA and LTDA programs. As detailed in PGE/100, Sims-Tinker 20, PGE "developed the long-term energy option as a mean of meeting state policy requirements and customer needs to comply with legislative requirements…" However, as part of Order No. 18-646 in PGE's UE 335 general rate case, the company and parties agreed to no LTDA tariff changes until 2022.

DRAFT letter to customers in the NLDA Queue

Date

Name
Company
Address
City State Zip

Dear [Name]:
Pursuant to Commission Order 19-03, PGE opened a non-binding queue for customers interested in Portland General Electric's (PGE) New Load Direct Access (NLDA) program on April 15, 2019. We have been requested to inform customers as to their position in the queue and the approximate amount of customer load ahead of them in the queue. The purpose of this letter is to provide such notification given that you have notified PGE of your intent to enroll in the NLDA program.

Be advised that this notification is based on information PGE has gathered from communications with those in the queue or their representatives, and rather than a specific load number, in some instances PGE has been provided a load range. We have not verified statements provided. In this notice we provide you an estimate of the amount of load ahead of you in the queue at this time. It is only an estimate and could change. Our proposed tariff, filed with the Oregon Public Utility Commission (OPUC), provides that we will determine the amount of load taken by a given customer under the cap, as the amount identified when a distribution services agreement is signed by the customer and the company. In all instances of customers in the queue, not one has signed a services agreement.

[INSERT THE PARAGRAPH BELOW THAT APPLIES TO THE SPECIFIC CUSTOMER IN THE LETTER]

For customer 1
As of today, [Company] is number 1 in the queue. The estimated load ahead of you in the queue is 0 MWa. It may be determined that you are not eligible to participate in the program since you are not a customer and do not have a qualifying site under the Oregon Administrative Rules governing eligibility. PGE is NOT taking action to remove you from the queue at this time.

For customer 2
As of today, [Company] is number 2 in the queue. The estimated load ahead of you in the queue is between 10 MWa and 11.5 MWa. We understand that your company's total projected load exceeds the 119MWa program cap. It may be determined that you are not eligible to participate in the program. PGE is NOT taking action to remove you from the queue at this time.

For customer 3
As of today, [Company] is number 3 in the queue. The estimated load ahead of you in the queue is between 38.5 MWa and 154 MWa. We understand that at the time you sent in your intent to enroll notice, your company had not yet secured land for its operational site. It may be determined that you are not eligible to participate in the program. PGE is NOT taking action to remove you from the queue at this time. See OARs 860-038-0700 through 860-038-0760.

For customer 4
As of today, [Company] is number 4 in the queue. The estimated load ahead of you in the queue is between 81.3 MWa and 196.8 MWa. We understand that your company's total projected load exceeds the 119MWa program cap. It may be determined that you are not eligible to participate in the program. PGE is NOT taking action to remove you from the queue at this time.

For customer 5
As of today, [Company] is number 5 in the queue. The estimated load ahead of you in the queue is between 153.3 MWa and 421.8 MWa.

For customer 6
As of today, [Company] is number 6 in the queue. The estimated load ahead of you in the queue is between 163.3 MWa and 431.8 MWa. We understand that your company's total projected load exceeds the 119MWa program cap. It may be determined that you are not eligible to participate in the program. PGE is NOT taking action to remove you from the queue at this time.

[END OF CUSTOMER-SPECIFIC INFO]

Eligible load for the program will be determined by the distribution services agreement you sign with PGE and will be for the load you identify in that agreement. This is according to PGE's proposed NLDA tariff which is under investigation by the OPUC. Questions of determining load eligibility and the cap may be taken up by the OPUC in its current investigation of PGE's NLDA program. Since this is a non-binding queue, any or all parties currently ahead of you in the queue may choose to revoke their notice prior to the tariff effective date.

Please direct any questions on the New Load Direct Access program to Andrew Speer at (503) 464-7486 or Andrew.Speer@pgn.com.

Sincerely,

Karla Wenzel
Manager, Pricing and Tariffs

July 3, 2019

TO: Greg Adams
Calpine Energy Solutions, LLC

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UE 358
PGE Response to Calpine Energy Solutions, LLC's Data Request No. 014
Dated June 19, 2019

Request:

Reference PGE/100, Sims-Tinker/21:11-14, stating, PGE will enter into "a customer contract" with each customer for NLDA service after notice is given committing to the NLDA program.

a. **Please supply PGE's form contract that it will use for this purpose for the NLDA program.**
b. **Please supply the current version of PGE's form contract used for opting into the Long-Term Direct Access program (i.e., the five-year program for existing loads).**
c. **Please explain any differences in treatment between NLDA and LTDA.**
d. **Please explain whether these form agreements will be approved by the Commission and why or why not.**

Response:

a. PGE is in process of drafting the NLDA agreement to be compliant with AR 614, the Company acknowledges that the outcome of this docket may change some of the terms.
b. The Long Term Direct Access contract is attached as Attachment A.
c. The differences are identified in PGE Responses to Calpine DR Nos. 10 and 12. When the Commission resolves issues raised with PGE Schedule 689 other differences may be identified.
d. PGE does not intend for the NLDA form contract agreement to be approved by the Commission. Similar to PGE's LTDA contract, the NLDA contract will implement the requirements for service per the terms and conditions of the applicable schedule(s), once approved, and PGE's tariff rules.

CERTIFICATE OF SERVICE

I hereby certify that I served the foregoing: **Portland General Electric Company's UE 358 Confidential Reply Testimony** on the following named persons on the date indicated below by U.S. Mail whose addresses appear on the attached service list established in this proceeding.

Dated this 5th day of August 2019.

Jay Tinker

Jay Tinker
Director, Rates and Regulatory Affairs
Portland General Electric Company
121 SW Salmon St., 1WTC0306
Portland, OR 97204
(503) 464-7805 (Telephone)
Email: jay.tinker@pgn.com

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