



**Portland General Electric**  
121 SW Salmon Street · Portland, Ore. 97204

September 6, 2019

Public Utility Commission of Oregon  
Attn: Filing Center  
201 High Street S.E., Suite 100  
P.O. Box 1088  
Salem, OR 97308-1088

RE: UE 358 New Load Direct Access Surrebuttal Testimony of Portland General Electric

Filing Center:

Submitted for electronic filing in UE 358 is Surrebuttal Testimony and Exhibits of Portland General Electric Company.

- UE 358 / PGE / 300
- Non-confidential exhibits 301 – 305

If you have any questions, please call me at (503) 464-7805. All formal correspondence, questions, or requests should be directed to the following email: [pge.opuc.filings@pgn.com](mailto:pge.opuc.filings@pgn.com).

Sincerely,

A handwritten signature in blue ink that reads "Jay Tinker". The signature is written in a cursive, flowing style.

Jay Tinker  
Director, Rates and Regulatory Affairs

**UE 358 / PGE / 300**  
**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*

September 6, 2019

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## I. Introduction

1 **Q. Please state your names and positions with Portland General Electric (“PGE”).**

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

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

5 Our qualifications were previously provided in PGE Exhibit 100.

6 **Q. What is the purpose of your testimony?**

7 A. The purpose of our testimony is to respond to the Rebuttal Testimony of the Public Utility  
8 Commission of Oregon (OPUC or Commission) Staff (Staff), the Alliance of Western  
9 Energy Consumers (AWEC), and Calpine Solutions (Calpine) filed regarding PGE’s New  
10 Load Direct Access (NLDA) investigation into Schedule 689. We collectively refer to these  
11 parties as Parties.

12 **Q. Please summarize the Parties’ positions in their rebuttal testimony?**

13 A. Staff recommends that the Commission defer judgment on PGE’s proposed Resource  
14 Intermittency Charge (RIC) and the Resource Adequacy Charge (RAD) for a general  
15 investigation that would address direct access (DA) issues more broadly, including whether  
16 the RIC/RAD should apply to both long term direct access (LTDA) and NLDA.<sup>1</sup> While  
17 Staff’s opening testimony calls for delaying NLDA program implementation to allow  
18 necessary time for quality decisions on important DA policy questions, Staff’s Rebuttal  
19 testimony suggests a shift -- that the NLDA program implementation does not need to be  
20 delayed. Staff also recommends that PGE’s proposed standard offer options intended to be

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<sup>1</sup> Staff/300, Gibbens/2.

1 compliant with the Oregon Renewable Portfolio Standard<sup>2</sup>, be deferred to a separate  
2 investigation or PGE’s next general rate case.

3 AWEC supports Staff’s position that the RIC and RAD be investigated in a separate  
4 policy docket and recommends that Schedule 689 be approved absent the RIC and RAD  
5 charges.<sup>3</sup> Additionally, AWEC echoes the same arguments as in their opening testimony  
6 that the basis of the RIC charge is a FERC jurisdictional charge and already captured by  
7 PGE’s imbalance charge under PGE’s Open Access Transmission Tariff (OATT).<sup>4</sup>

8 Calpine agrees with both Staff and AWEC that a separate, more general investigation  
9 for the RIC and RAD is warranted to study resource adequacy (RA) as it relates to long-term  
10 planning and the associated procurement of capacity resources, and alternatives to the  
11 proposed charges.<sup>5</sup> Calpine also argues that Schedule 689 should not be held in abeyance  
12 pending a RIC and RAD investigation. Calpine responds to our reply testimony regarding  
13 RA and reiterates its claim that the RAD charge is unwarranted given how Calpine acquires  
14 energy.<sup>6</sup> However, Calpine provides an alternative proposal regarding the use of demand  
15 response, which we discuss later in our testimony. Calpine goes on to allege that the RIC  
16 charge is duplicative to PGE’s imbalance OATT charge (PGE OATT Schedule 4R).<sup>7</sup>

17 **Q. How is the remainder of your testimony organized?**

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<sup>2</sup> ORS 469A.052.

<sup>3</sup> AWEC/200, Mullins/4.

<sup>4</sup> See PGE OATT, Schedule 4 Energy Imbalance Service, At Page 72.

[https://demo.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE8\\_14\\_04Tariff.pdf](https://demo.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE8_14_04Tariff.pdf)

<sup>5</sup> Calpine/300, Higgins/2.

<sup>6</sup> Calpine/200, Higgins/9.

<sup>7</sup> Calpine/200, Higgins/12.

1 A. In our introduction, we discuss the regional market conditions for RA and how it pertains to  
2 the charges we've proposed in this docket. The remainder of our testimony is organized as  
3 follows:

- 4 • The application and methodology of the RAD charge;
- 5 • The implementation and application of the NLDA queue and cap;
- 6 • Other remaining issues, such as the standard offer options, costs associated with  
7 RPS compliance, and the NLDA service agreement.

8 Lastly, we conclude our testimony in this docket.

## **II. The Commission Must Consider NLDA Impacts on Resource Adequacy**

1 **Q. Why should the Commission consider impacts on RA when making a determination on**  
2 **PGE's NLDA filing?**

3 A. As the Commission is aware, the region continues to move toward a capacity shortfall  
4 driven by resource retirements. This shortfall is forecasted to present itself as soon as 2021.  
5 The immediate effects of a regional capacity shortfall may be masked by seasonal hydro  
6 conditions, but will continue to present as large amounts of capacity are removed from  
7 service and not replaced. As PGE has maintained in this proceeding, expanding the DA  
8 program through NLDA, without ensuring that capacity is available to serve these new  
9 loads, will deepen the RA challenge faced by PGE and the region. By definition, NLDA  
10 loads are unplanned for, and any loads associated with the program will be in addition to the  
11 loads assumed in RA assessments. It is essential for the Commission to ensure that the  
12 NLDA program decisions made for load service within the Commission's jurisdiction  
13 account for RA needs. To implement a NLDA program without RA solutions, even on a  
14 provisional basis, would unnecessarily jeopardize the reliability of the electric system and  
15 place the burden squarely on cost of service customers.

16 **Q. Is the Commission able to decide whether NLDA customers must support RA within**  
17 **this docket?**

18 A. Yes. The purpose of UE 358 is to investigate PGE's Advice No. 19-02 and the charges and  
19 options PGE proposed. More specifically, the intent of UE 358 is to investigate supply  
20 reliability, RA, and the ability for PGE to charge NLDA customers (via Schedule 689) the  
21 RIC and RAD charges to maintain these fundamental services. The record within this  
22 docket is sufficient to resolve the important question of whether NLDA customers are

1 responsible to support RA in addition to the specific capacity charges in PGE's NLDA --  
2 Schedule 689.

3 **Q. Do the Parties agree that regional capacity and RA are of concern in the Northwest?**

4 A. Yes. Staff and AWEC both agree that RA is an issue of regional concern that warrants an  
5 investigatory docket to equitably apportion and allocate the costs associated with RA.<sup>8</sup>  
6 Calpine's rebuttal testimony recognizes that the region's RA is increasingly strained by  
7 resource retirements.<sup>9</sup> CUB strongly agrees with PGE that the RIC and RAD are necessary  
8 in order to prevent unwarranted risk and cost shifting to COS customers as RA becomes  
9 increasingly concerning. CUB opposes an expansion of DA policy in which COS customers  
10 alone pay for the fixed costs of generation and unduly face the RA costs and risks  
11 originating from DA customers.<sup>10</sup>

12 **Q. What procedural recommendations do Parties make in their rebuttal testimony?**

13 A. Staff's primary recommendation is for the Commission to approve PGE's NLDA tariff  
14 without PGE's proposed capacity charges and the new standard offer service option, and to  
15 consider the RA concerns in a future DA policy docket. AWEC and Calpine support Staff's  
16 procedural recommendation. Calpine also indicates conditioned support for Staff's  
17 alternative recommendation offered in Staff's opening testimony.<sup>11</sup> Under the alternative  
18 approach, NLDA customers would pay for RIC and RAD service on a provisional basis, the  
19 costs of which can be offset through voluntary participation in demand response programs.<sup>12</sup>  
20 PGE responds to Calpine's alternative later in this testimony.

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<sup>8</sup> Staff/300, Gibben/2-3 and AWEC/200, Mullins/6.

<sup>9</sup> Calpine/200, Bass/4.

<sup>10</sup> CUB/100, Jenks/3.

<sup>11</sup> Calpine/300, Higgins/2.

<sup>12</sup> Id.



1 **Q. What are the Parties' primary rationale for approving the NLDA tariff without the**  
2 **RIC and RAD?**

3 A. Staff's primary rationale is that RA is not a concern in the near term.<sup>13</sup> As such, Staff  
4 argues the Commission should allow for an expansion of new loads even when there is no  
5 entity responsible to secure capacity, and to consider solutions for RA needs at a later time.  
6 Staff argues that even if PGE were to assess capacity charges on ESSs, that incremental  
7 improvements to PGE's system RA would not occur for over a year and a half, by which  
8 time Staff estimates a DA policy investigation may be complete.<sup>14</sup> AWEC argues that the  
9 incremental amount of 119 MWa unplanned for NLDA load would not create any reliability  
10 concerns in the Northwest.<sup>15</sup> Calpine recognizes that regional reliability may be  
11 compromised in the near term and that actions are necessary in order to maintain the current  
12 level of reliability we expect today. Yet, contrary to PGE's proposal, Calpine argues that  
13 capacity solutions should be delivered both through integrated utilities and from DA  
14 suppliers.<sup>16</sup>

15 **Q. How do you respond?**

16 A. Staff and AWEC's rationale is flawed and should be rejected. In fact, RA and reliability are  
17 pressing issues in our region with supply-demand balances already strained under peak and  
18 contingency conditions. We respond to Calpine's proposal for third-party supply of needed  
19 capacity later in this testimony.

20 **Q. What does PGE rely on in its claim that RA is a pressing issue and should be**  
21 **addressed in the context of this docket?**

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<sup>13</sup> Staff/300, Gibbens/4.

<sup>14</sup> Staff/300, Gibbens/ 4-5.

<sup>15</sup> AWEC/200, Mullins/4-5.

<sup>16</sup> Calpine/200 Bass/4.

1 A. The Northwest Power and Conservation Council’s draft Resource Adequacy Assessment  
2 forecasts a regional loss of load probability (LOLP) of 7-8% in 2021 under reference case  
3 assumptions.<sup>17</sup> Adding new, large, unplanned-for NLDA loads will only increase the  
4 magnitude of the RA deficit and LOLP.

5 **Q. Key to Staff’s recommendation is that if an investigation were to be opened, it would**  
6 **be resolved in about a year. Do you share Staff’s optimism that an investigatory**  
7 **docket will be resolved in about a year?**

8 A. No. Staff’s suggestion that a general DA policy investigation may be completed in  
9 approximately one year is optimistic.<sup>18</sup> In our experience with DA in other regulatory  
10 proceedings (e.g. UE 236 and UM 1587), the scope of the investigations tend to be broad,  
11 time consuming, contentious, with conclusions that could require changes of Commission  
12 rule or even recommended changes of state law. The scope of the Commission’s desired  
13 proceeding may continue for several years – a time in which the reliability of regional  
14 power supply appears threatened. The recommendation to delay suggests that the Staff view  
15 resource inadequacy as an acceptable risk. Staff’s primary recommendation would delay  
16 decisions on planning and acquiring capacity resources while simultaneously facilitating  
17 large unplanned-for loads (perhaps even beyond the 119 MWa cap) to be served by entities  
18 with no plans or obligation to secure physical capacity resources.

19 **Q. Does PGE support this procedural recommendation?**

20 A. No. We strongly oppose this procedural recommendation. Were the Commission to adopt  
21 Staff’s primary recommendation, the Commission would be contributing to a deepening of

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<sup>17</sup> See PGE Exhibit 301.

<sup>18</sup> Staff/300, Gibbens/4.

1 the region's reliability risk challenges. NLDA customers, and the reliability risks they  
2 create, are squarely within the jurisdiction of the Commission. While the Commission may  
3 face limits in implementing broad, regional RA solutions, in this instance the Commission  
4 can and should take meaningful steps to improve RA conditions for load serving entities in  
5 its jurisdiction. The Commission must consider the immediate impacts of NLDA on RA  
6 and should not implement the NLDA program without a solution, interim or otherwise. Not  
7 doing so only serves to deepen the problem.

8 **Q. Is PGE opposed to additional consideration of RA in a DA general investigatory**  
9 **docket?**

10 A. PGE welcomes additional discussion of RA concerns for DA customers broadly. However,  
11 we firmly maintain that Schedule 689 should not go into effect until the Commission makes  
12 a determination (either final or provisional) regarding the need for RA planning and  
13 procurement requirements applicable to all load, and for NLDA customers to fairly support  
14 contribute to system reliability costs. Furthermore, NLDA customers should understand that  
15 they will not freely socialize reliability costs to COS customers prior to enrolling.

16 **Q. Should the Commission choose to review PGE's proposed capacity charges in a**  
17 **general DA investigation, has PGE proposed an alternative approach that does not**  
18 **adversely impact customers while also not further impacting the region's RA?**

19 A Yes. Should the Commission choose to review PGE's proposed RIC and RAD within a  
20 general policy docket, the Commission should allow NLDA customers to commence service  
21 as cost of service customers while maintaining position in the NLDA queue. To do this, the  
22 Commission could find good cause to allow a waiver of its conflicting rules. Following the  
23 conclusion of the policy docket and any associated rule-making, PGE proposes allowing

1 those queued customers to choose between COS or NLDA tariffs. This approach strikes the  
2 right balance between the interests of large, sophisticated industrial users and the interests of  
3 COS customers who would be subject to undue cost and risk shifts from NLDA customers  
4 should the program be approved without the necessary structure to preserve RA.  
5 Alternatively, PGE would continue to waive any obligation for a Commission determination  
6 on its NLDA tariff filing, and the program can be held in abeyance until the policy  
7 investigation is complete.

8 **Q. Does PGE support any other alternative approaches offered by Parties?**

9 A. PGE continues to conditionally support Staff's alternative proposal offered in its opening  
10 testimony subject to important clarifications.<sup>19</sup> Calpine's rebuttal testimony also indicates  
11 conditional support for Staff's alternative proposal.<sup>20</sup> As originally suggested by Staff and  
12 clarified by PGE, during the pendency of a broader DA policy docket, all NLDA customers  
13 must make RIC and RAD payments to PGE to support reliability. Should NLDA customers  
14 choose to participate in PGE's demand response program, NLDA customers would be  
15 eligible to receive program participation payments which would fully or partially offset the  
16 capacity payments made to PGE. This interim solution would allow for customers to  
17 initiate service while directly contributing to the system's capacity needs. Calpine's rebuttal  
18 testimony indicates conditional support for this approach subject to the creation of a unique  
19 demand response tariff for NLDA customers with unique payment and performance  
20 requirements.<sup>21</sup> Following additional direction from the Commission, PGE would consider  
21 demand response program design recommendations in a subsequent NLDA compliance or

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<sup>19</sup> Staff/100, Gibbens/10.

<sup>20</sup> Calpine/300, Higgins/4.

<sup>21</sup> Calpine/300 Higgins/7.

1 demand response tariff filing. However, it is also important to recognize that the efficacy of  
2 such approach, even on a provisional basis, would be dependent upon DR program design,  
3 participating customer demand and load-shape, as well as the value of alternative sources of  
4 capacity.

5 **Q. What are the additional reasons Parties have given for the NLDA tariff being**  
6 **approved without the RIC and the RAD?**

7 A. Staff seeks to prevent further delay to customers who want to participate in NLDA who  
8 have provided notice and are in the queue; allow more process to investigate the RIC and  
9 RAD and alternatives to the RIC and RAD; and to allow for the consideration of applying  
10 such charges to LTDA as well as NLDA customers. AWEC and Calpine provide similar  
11 arguments with the additional claim that there is no harm from a delayed decision on the  
12 RIC and RAD.

13 **Q. If PGE's NLDA program is delayed, please address the concern that PGE would be**  
14 **harming customers who have queued their intent to enroll.**

15 A. Were PGE's NLDA program to be delayed, potential customers would not be unduly  
16 harmed. As offered by PGE, all queued customers are free to advance their business plan  
17 and commence electric service while retaining the opportunity to either choose COS or  
18 participate in the NLDA program once important reliability, risk and equitable cost  
19 allocation questions area addressed. This approach ensures that eligible customers are not  
20 unduly harmed by investing in their facility due to a mistaken assumption about what  
21 NLDA prices, terms, and conditions are prior to the completion of a DA policy  
22 investigation.

1           Again, the intent of this docket is to make determinations on the aspects of PGE’s 19-02  
2           Advice filing that were not addressed in the NLDA rules. We strongly believe that it is in  
3           the best interest of all customers and the integrity of the electric system to provide  
4           determinations in this proceeding in order to ensure fairness for cost of service (COS)  
5           customers on a going forward basis as more DA loads come into PGE’s balancing authority  
6           area (BAA).

### III. Issues and Responses

#### A. The RAD

1 **Q. Please briefly summarize PGE’s proposed RAD and its purpose.**

2 A. The RAD is a capacity-based charge to NLDA customers that reflects the cost of  
3 maintaining and providing RA. Given the nature of RA, the need for long-term planning  
4 and acquisition of physical capacity resources, and PGE’s obligation to provide system  
5 reliability for all, it is a service that benefits all customers and should likewise be fairly paid  
6 for by all customers.

7 **Q. Has PGE made any modifications to the RAD since its opening testimony?**

8 A. No. However, through discovery and in our reply testimony, we provided alternatives for  
9 Parties to consider with regards to NLDA customers participating in demand response as a  
10 means of voluntary curtailment to provide RA and partially or fully offset the RAD related  
11 requirement.<sup>22</sup>

12 Additionally, while not a modification to our proposal, we discuss our proposed  
13 functionalization approach below.

14 **Q. Please address the concerns that the RAD is discriminatory.**

15 A. We see the question of discrimination raised by Parties to be a legal question and will  
16 address it fully in briefs. However, there is nothing in this docket that suggests a  
17 Commission decision regarding PGE’s proposed NLDA program will directly impact  
18 LTDA rates. PGE fully expects that if it were to seek to apply the RAD, or some other  
19 similar charge, to LTDA customers, the Commission would need to weigh the facts and

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<sup>22</sup> PGE/200, Sims – Tinker/16.

1 circumstances of such a request regardless of its decision in this docket. As we have  
2 explained throughout our testimony in this docket, NLDA and LTDA are fundamentally  
3 distinct with the former being unplanned for and subject to different program rules. In fact,  
4 we note that the Commission made a similar finding in authorizing the NLDA program.<sup>23</sup>  
5 While RA application is a broad concern that spans more than NLDA, the Parties have  
6 provided little support as to why the Commission would not have the authority to establish  
7 and implement the RAD charge for Schedule 689 in advance of a determination for LTDA.

8 I. Supplying Resource Adequacy

9 **Q. Do all Parties agree that RA is important?**

10 A. Yes. As we have previously stated, Parties generally accept that RA is a foundational  
11 requirement of a reliable electric system and a fundamental societal good. Calpine states  
12 that as “existing fossil fuel generation is retired, that the ‘region’s resource adequacy needs’  
13 will increase in order to support the current levels of reliability to which we all have become  
14 accustomed and is required for a modern society.”<sup>24</sup> AWEC agrees that “maintaining resource  
15 adequacy is important” and goes on to state that “if evidence shows that direct access  
16 customers are not maintaining the appropriate level of resource adequacy, this should be  
17 rectified.”<sup>25</sup> Additionally, AWEC “agrees that cost of service customers should not  
18 subsidize direct access customers in any response, including with regard to resource  
19 adequacy.”<sup>26</sup>

20 **Q. What are the Parties’ positions on the supply of RA and the need for the RAD?**

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<sup>23</sup> See PGE’s comments in AR 614 filed on June 19, 2018, at page 15.

<https://edocs.puc.state.or.us/efdocs/HAC/ar614hac73158.pdf>

<sup>24</sup> Calpine/200, Bass/4.

<sup>25</sup> AWEC/200, Mullings/6-7.

<sup>26</sup> *Id.*



1 A. AWEC disagrees that PGE has adequately demonstrated that DA, specifically NLDA in this  
2 docket, customers do not provide the appropriate levels of RA and therefore the RAD is  
3 unnecessary.<sup>27</sup> Calpine agrees that the RAD is a RA cost and that reliability is a “policy  
4 imperative” and the Commission should determine what service the RAD is providing and  
5 “whether all, some or none of the RAD can be supplied by the ESSs.”<sup>28</sup> Staff does not  
6 agree that RA is a need in the near term issue for PGE and expresses concern that the costs  
7 of RA are high even if there is a need..<sup>29</sup> Although CUB did not file a second round of  
8 testimony in this docket it is clear from reply testimony that CUB supports the need for the  
9 RAD as “the lack of capacity in the wholesale market is a fundamental problem that must be  
10 addressed” and the RAD “is a reasonable way to address the problem.”<sup>30</sup>

11 **Q. In his testimony, Mr. Bass asserts that Calpine provides RA service via “firm  
12 liquidated damage (“firm LD”) contracts”.<sup>31</sup> Do you agree?**

13 A. No. Calpine’s description and use of a firm LD contract only serves as a financial  
14 mechanism to provide monetary compensation if a supplier fails to deliver energy.<sup>32</sup>  
15 Calpine states as much in its testimony by describing a firm LD contract as an agreement  
16 where “Firm service may be curtailed within mutually agreed to recall times...If the seller  
17 interrupts, it will pay damages consistent with the terms of the contract...”<sup>33</sup> A firm LD  
18 contract only provides a financial incentive for suppliers and does not require the  
19 identification or availability of physical resources to ensure supply. Reliance on “Firm LD”

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<sup>27</sup> *Id.*

<sup>28</sup> Calpine/200, Bass/12-13.

<sup>29</sup> Staff/300, Gibbens/4 and Gibbens/10.

<sup>30</sup> CUB/100, Jenks/17.

<sup>31</sup> Calpine/200, Bass/3.

<sup>32</sup> *Id.*

<sup>33</sup> *Id.*

1 energy purchases suggests that financial damages provide an acceptable substitute for  
2 system reliability and the avoidance of undesirable electric service curtailments – we  
3 strongly disagree with such premise.

4 Calpine goes on to suggest it is contributing to RA, arguing that if contracts for firm  
5 power from an unspecified source with liquidated damages is good enough for California’s  
6 RA requirements it should be good enough for PGE.<sup>34</sup> The suggestion is misleading as  
7 Calpine does not disclose that the use of unspecified resources imported into California to  
8 meet RA requirements has been flagged by California ISO’s Department of Market  
9 Monitoring (DMM) as an issue of concern that should be addressed. Like PGE the DMM  
10 argues that using unspecified market purchases originating out of system may have limited  
11 availability and value during emergency system conditions.<sup>35</sup> Additionally, Calpine seems  
12 to share these concerns as it stated, in the California proceeding, “Calpine does share  
13 Energy Division’s concerns that import RA capacity may not be back by physical resources  
14 and transmission and hence may not be available when needed...”<sup>36</sup>

15 Regardless of these points, Calpine’s argument that it is supporting RA appears to rely on  
16 the fact that there is no legal obligation for Calpine to support RA. Calpine correctly notes  
17 that “PGE has not identified any Commission rule or law that Calpine Solutions has  
18 violated...”<sup>37</sup> The ability for Calpine to freely socialize reliability costs onto COS  
19 customers is not present in other jurisdictions where it conducts business. Calpine freely  
20 admits that in other jurisdictions it is required to take actions that support RA and that it

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<sup>34</sup> *Id.*

<sup>35</sup> Resource Adequacy Enhancements Issue Paper. California ISO. October 22, 2018.  
<http://www.caiso.com/Documents/IssuePaper-ResourceAdequacyEnhancements.pdf>

<sup>36</sup> Calpine Corporation Comments on Clarification to Resource Adequacy Import Rules, page 2.  
<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M309/K943/309943892.PDF>

<sup>37</sup> Calpine/200, Bass/4

1 does not take those same actions on behalf of its Oregon customers because it is not  
2 required.<sup>38</sup> Calpine has disclosed that it does not engage in long-term power supply  
3 agreements.<sup>39</sup> Instead Calpine indicates that to supply power to its customers it relies  
4 exclusively on shorter term market purchases without specified sources of supply.  
5 Calpine’s activities clearly do not support RA and, therefore, shift costs onto COS  
6 customers as a result.

7 **Q. If Calpine’s suppliers do not deliver physical energy, then is Calpine required to**  
8 **ensure adequate supply is available to serve their customers?**

9 A. No. Calpine describes the service it provides to its customers as “extremely simple; we buy  
10 wholesale and sell retail.”<sup>40</sup> Calpine’s described service manages credit and price risk.  
11 Notably, Calpine’s described service does not include any assurance of adequacy or  
12 reliability.<sup>41</sup> PGE alone is left with the obligation to serve the load of all customers if  
13 Calpine is unable to secure or deliver necessary supply. As demonstrated in PGE/200  
14 testimony, this occurs with relative frequency<sup>42</sup>. In Calpine’s rebuttal testimony, Calpine  
15 admits that its sources of supply were unavailable to meet load eleven hours in 2018.<sup>43</sup> This  
16 is of great concern to PGE as we are not presently allowed to plan or procure capacity  
17 necessary to provide this physical supply, which becomes increasingly challenging as the  
18 regional supply, and the surplus energy market Calpine relies on, continues to become more  
19 constrained due to unit retirements.

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<sup>38</sup> *Id.*

<sup>39</sup> See PGE Exhibit 302.

<sup>40</sup> Calpine/200, Bass/5.

<sup>41</sup> Calpine/200, Bass/5-6.

<sup>42</sup> PGE/200, Sims – Tinker/32, Table 1.

<sup>43</sup> Calpine/200, Bass/8.

1 **Q. AWEC also relies on the concept of firm LD contract being sufficient to supply RA.<sup>44</sup>**

2 **How do you respond?**

3 A. AWEC relies on FERC Order 890 which allowed certain types of contracts to be designated  
4 as network resources for purposes of procuring network transmission service to deliver to  
5 load within a balancing authority. FERC found that,

6 the inclusion of a ‘make whole’ LD provision...does not disqualify that  
7 agreement from being designated as a network resource. However, other types of  
8 LD provisions may create incentives that are incompatible with the firmness of a  
9 power purchase agreement....Thus, as of the effective date of the Final Rule,  
10 power purchase agreements designated as network resources may only contain  
11 LD provisions that are of the ‘make whole’ type.<sup>45</sup>

12 As can be observed above, FERC did not comment on the contribution to RA from firm LD  
13 contracts. Rather, FERC provided clarification regarding what resources may qualify to be  
14 a designated network resource for use of network transmission. Even if FERC had directly  
15 linked designated network resources with RA, as of the date of filing this testimony, PGE  
16 and BPA are the only two entities with load in the PGE BAA that have designated network  
17 resources shown on PGE’s OASIS.

18 AWEC goes on to maintain that DA customers are exposed to the RA risk of their supply  
19 choice arguing that, “one of the primary reasons customers choose DA is to have control  
20 over their electricity supply (including the associated risks and benefits), and RA is a  
21 component of this supply.”<sup>46</sup> However, it is clear that RA is not a component of supply  
22 derived from unspecified sources in the short-term wholesale energy market. Additionally,  
23 the obligation of PGE to provide service to all loads within the balancing authority  
24 regardless of customer class does not support AWEC’s suggestion that NLDA customers

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<sup>44</sup> AWEC/200, Mullins/8.

<sup>45</sup> FERC Order No. 890, page 867, paragraph 1455.

<sup>46</sup> AWEC/200, Mullins/9.

1 will be exposed to the risks of their participation in the program. Rather should the  
2 Commission approve the NLDA program absent the RAD, NLDA customers will receive all  
3 reliability benefits while pushing the costs and risks onto COS customers.

4 **Q. Is AWEC correct that PGE also uses firm LD contracts?**

5 A. Yes. In response to AWEC DR 028, PGE stated that it “actively participates in the  
6 wholesale energy market to economically dispatch its generating units and reduce  
7 customers’ net variable power costs.”<sup>47</sup> However, the response also goes on to state that  
8 while “the potential output of PGE’s generating units may be economically displaced by  
9 wholesale energy market purchases, however those units remain available to provide a  
10 physical source of power if required.”<sup>48</sup> While PGE may optimize assets in the wholesale  
11 energy market on behalf of cost of service customers who pay for said assets, those assets  
12 still remain available to ensure RA even for customers who do not contribute to the costs.  
13 Allowing the NLDA program to move forward absent the RAD will result in a further  
14 increase of this cost and risk shifting.

15 **Q. Does PGE agree with Staff’s calculation of the daily reliability costs associated with the  
16 RAD that AWEC cites in its testimony?**<sup>49</sup>

17 A. No. Staff’s estimate relies upon a mistaken methodology. In response to PGE’s Data  
18 Request 03<sup>50</sup>, Staff’s workpapers reveal that the estimate is based upon the forecasted RAD  
19 payments for an average LTDA customer over 10 years divided by seven (the number of  
20 days Staff estimates as the difference in the loss of load expectation (“LOLE”) when  
21 considering COS and DA). That is incorrect. PGE’s 2019 IRP filing shows that a fully

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<sup>47</sup> AWEC/201, Mullins/6.

<sup>48</sup> *Id.*

<sup>49</sup> AWEC/200, Mullins/10.

<sup>50</sup> See PGE Exhibit 303.

1 subscribed LTDA and NLDA program would increase all customers LOLE to  
2 approximately 22 days per 10 years as opposed to PGE’s targeted reliability level of 1 day  
3 per 10 years, indicating an increase of twenty-one days rather than seven.<sup>51</sup> PGE also finds  
4 Staff’s usage of a reliable day per customer metric to be misleading. When correcting Staff’s  
5 analysis to include all existing LTDA customers, their associated on-peak demand, the  
6 resultant cost of reliability per day is more than 10 times smaller. Regardless, a more  
7 appropriate reliability cost metric would consider the cost per MW or MWh or improved  
8 service, which would reflect a low cost in terms of loss of load events. Even still, the above  
9 numbers would reflect the payments necessary for DA customers to improve reliability for  
10 all customers served by PGE not LTDA customers alone. Simply put, Staff’s estimate of  
11 reliability costs included in opening testimony is incorrect and should not be relied upon for  
12 decisions in this proceeding.

13 2. Pricing and Functionalization

14 **Q. Did Parties share any concerns regarding methods to establish RAD pricing?**

15 A. Yes. Staff, AWEC and Calpine all took issue with the limited amount of information on the  
16 methodology PGE would use to functionalize RA in the context of a cost of service study.

17 **Q. How do you respond?**

18 A. PGE appreciates Parties’ understandable interest in desiring an established methodology to  
19 derive PGE’s RAD costs and a finer estimate of PGE’s expected costs. However, we  
20 maintain that the appropriate proceeding to review the segments of PGE’s revenue  
21 requirement that are in service to RA is a general rate case. Nonetheless, we do see value in

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<sup>51</sup> PGE’s 2019 IRP, page 125.

1 further establishing the guiding principles of PGE’s proposed functionalized RA costs.

2 PGE’s RA functionalization principles are as follows:

- 3 • RA is a service supplied through the provision of capacity and the costs of RA  
4 are attributable to all customers and classes (regardless of energy supplier);
- 5 • Costs associated with providing firm capacity from physical resources should  
6 be functionalized to RA service;
- 7 • Each resource’s contribution is unique and dependent on the resource’s  
8 characteristics;
- 9 • Each class’ or schedule’s need is unique and dependent on the characteristics  
10 of that class or schedule;
- 11 • Existing and incremental resources costs will be evaluated on the equivalent  
12 methodological basis and spread to all customers based on cost causation  
13 principles;
- 14 • A general rate case (GRC) is the most transparent and equitable way to  
15 functionalize costs associated with RA.

16 **Q. Did PGE change its approach to calculating the RAD charge from its initial to its**  
17 **responsive testimony?**

18 A. No. We continue to propose that the RAD price be calculated in the context of a GRC and  
19 RA be a service that is apportioned to all rate schedules and classes of customers.  
20 Apportioning costs by the cost of service study ensures that cost allocation and pricing is  
21 based on the amount of cost causation each schedule is placing upon PGE’s system with  
22 regard to RA.

23 **Q. Please review the process to determine the RAD charge.**

1 A. In general, we see price setting for the RAD as following the same general process for any  
2 price:

- 3 • Establish the revenue requirement;
- 4 • Allocate (or functionalize) the revenue requirement by category (e.g. generation,  
5 distribution, transmission, and RA);
- 6 • Conduct a rate spread study to apportion the functionalized categories of costs to each  
7 rate schedule.

8 We expect that the price setting for the RAD will occur in the context of a GRC and  
9 therefore, will leverage the revenue requirement, generation marginal cost, and rate spread  
10 studies to determine and spread the costs attributable to RA and apportion those costs  
11 equitably based on cost causation principles.

12 **Q. What will be the basis for functionalizing costs associated with RA?**

13 A. Given the range of resources in PGE's generating fleet and the prospective incremental  
14 generating resource acquisitions, we expect to leverage PGE's net variable power cost  
15 (NVPC) and marginal generation cost studies along with the embedded costs of firm  
16 generation to calculate and allocate the portion of the generation revenue requirement that's  
17 associated with RA.

18 **Q. How would PGE allocate costs to rate schedules?**

19 A. Given that generation capacity and RA are a part of total generation, the generation marginal  
20 cost study provides the forum for providing a transparent method to spread system RA costs  
21 across rate schedules for pricing purposes. In the study, PGE will use an allocation factor  
22 (which assess RA need by schedule), similar to the existing coincident peak or total energy



1 consumption factors, to determine each rate schedules RA proportional need. Thus,  
2 following the existing practices and principles that PGE currently uses for setting rates.

3 **Q. Will RA be a category of cost that applies to all customer rate schedules (COS and**  
4 **DA)?**

5 A. Yes. As we've stated in the previous rounds of testimony in this docket, RA is a service  
6 that's currently provided to all customers but paid for only by COS customers.<sup>52</sup>  
7 Historically, the costs of RA have been embedded in generation costs that show up in  
8 customer bills via their energy charges. This approach has over-simplified the service costs  
9 and allowed customers who do not receive supply from PGE to receive RA service while  
10 bypassing the associated costs. Through functionalizing RA, we plan to apply pricing for  
11 RA across all rate schedules ensuring that no class is able to receive the benefits of RA  
12 while other classes bear the costs.

13 **Q. Why isn't PGE proposing its exact methodology and RAD price in this docket and**  
14 **instead developing the pricing methodology in a general rate case (GRC)?**

15 A. The appropriate proceeding to determine the exact RAD pricing is in a GRC. Given that RA  
16 is a service provided to all customers (regardless of the energy provider) and is not currently  
17 separately functionalized, a GRC is the only forum which allows PGE to propose new rate  
18 design proposals via a COS and rate design studies. Also, a GRC provides all intervening  
19 parties an equal chance to provide comment and recommendations for alternative pricing  
20 design structures and methodology on PGE's proposal for RAD pricing which helps to  
21 ensure an equitable spread of costs across all rate schedules.

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<sup>52</sup> PGE/200, Sims – Tinker/32.

1 **Q. Is PGE proposing the Commission defer its decision on the RAD until the Company's**  
2 **next GRC?**

3 A. No. PGE is not changing its proposal. Rather, we are explaining that the GRC is the most  
4 appropriate forum for PGE and parties to propose, review, and comment on specific pricing  
5 and rate design aspects. We continue to request that the Commission approve the RAD in  
6 this docket so that the specific rate design aspects can be handled in a subsequent GRC.

7 **Q. PGE's proposal to determine the exact charge for the RAD in its next general rate case**  
8 **means it is not known to customers until then. Is this in conflict with PGE's argument**  
9 **that the terms and conditions be known to customers before they enroll in NLDA?**

10 A. No. As part of our Schedule 689 advice filing (No. 19-02), we provided an indicative RAD  
11 price based on IRP analysis; however, we acknowledged that the actual RAD price may be  
12 different depending on circumstances such as incremental resource procurement or the  
13 specific rate design approach in a subsequent GRC. PGE's argument is that prospective  
14 NLDA customers should know that they are eligible for the RAD and it is a charge that will  
15 apply to their service. However, we are open to providing indicative pricing after this  
16 docket once we have the associated cost/pricing results for the RAD.

17 3. *RAD Alternatives*

18 **Q. Have Parties discussed alternative mechanisms that might ensure RA and allow**  
19 **customers to avoid or mitigate the RAD?**

20 A. Yes. In its reply and rebuttal testimony Staff discussed the concept of "self-supply" of RA  
21 in the form of a third-party solution, self-generation, and demand response or curtailment.<sup>53</sup>  
22 Calpine's rebuttal testimony considers the potential for ESSs to self-supply necessary

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<sup>53</sup>Staff/100 Gibbens/18-19 and Staff/300 Gibbens/8-9.

1 capacity resources and the potential for NDLA customers to avoid RAD charges through  
2 participation in demand response programs (Calpine offers specific recommendation on  
3 adjusted demand response tariffs for DA customers).<sup>54, 55</sup>

4 In its testimony, AWEC states “there are any number of alternatives” and references the  
5 704B framework in Nevada as well as long-term contracts with specified resources (e.g.  
6 third-party supply) but does not appear to propose any specific alternatives.<sup>56</sup>

7 **Q. Please continue.**

8 A. As we discussed in our testimony and responses to data requests<sup>57</sup>, these concepts could all  
9 be developed to support RA.<sup>58</sup> In particular, demand response and self-generation resemble  
10 existing constructs that PGE has implemented, specifically Schedule 26 – Nonresidential  
11 Demand Response Pilot Program and Schedule 75 – Partial Requirements Service, and  
12 could be readily adapted to the framework suggested by Parties in this docket.

13 While PGE recognizes that NLDA customers or their ESS have the ability to enter into  
14 long-term contracts with physical resources and that such a construct could meet RA  
15 requirements, PGE has concerns with such a third-party supply of RA resources for  
16 numerous reasons.

17 **Q. What primary concerns does PGE have with a third-party supplied option?**

18 A. As we stated in our reply testimony, PGE is actively regulated under broad Commission  
19 authority and is the sole entity responsible and accountable for providing reliability to  
20 customers within its balancing authority, regardless of their energy supplier. Neither the

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<sup>54</sup> Calpine/100 Higgins/9 and Calpine/300 Higgins/7.

<sup>55</sup> Calpine/200, Bass/2.

<sup>56</sup> AWEC/200 Mullins/9-10.

<sup>57</sup> See PGE Exhibit 304.

<sup>58</sup> PGE/200 Sims – Tinker/25-26.

1 obligation to serve nor level of Commission oversight apply to a third-party, and it does not  
2 appear that the Commission currently has the authority to extend such a framework to third-  
3 parties. PGE expects that voluntary standards imposed on a financially incented third party  
4 will fall short. It is our position that a third-party option with no oversight, accountability,  
5 or enforcement does not provide RA.

6 **Q. Does PGE have concerns with the other options as well?**

7 A. Yes, but to a lesser extent because the options raised by Parties all fit into a framework  
8 where the Commission has oversight. PGE acknowledges that these options require further  
9 development and analysis, but there is sufficient time to do so under the proposed  
10 implementation of NLDA and the RAD, specifically as part of a general investigation  
11 regarding DA or within a subsequent general rate case.

12 **Q. Would any of the above alternatives replace the RAD? Why?**

13 A. No. Instead, PGE recommends the Commission approve the RAD and allow for some, or  
14 possibly all, of the above alternatives to be further investigated and potentially implemented  
15 to serve to partially or fully offset the RAD. The ability to and degree of offset would  
16 depend on the details of the proposed alternative.

**B. NLDA Queue and Program Cap**

17 **Q. Are there any customers in the queue that have already energized such that they would**  
18 **not be eligible under Commission rules?**

19 A. We have questions of eligibility around a few customers in the queue. One of the  
20 customers, whose eligibility was in question, has energized their operations, which  
21 according to the rules, makes them ineligible for NLDA. No others have energized.

1 **Q. AWEC alleges that PGE has changed its position regarding energization and**  
2 **eligibility. Is this correct? Please explain PGE's position.**

3 A. No. Our perceived change in position is largely due to Parties' recommendation that the  
4 final determination for the RIC and RAD be made in a separate docket. As an interim  
5 solution where customers could still energize and begin operations prior to a final  
6 determination on the RIC and RAD and assuming a suspension of Schedule 689, we  
7 proposed that customers be allowed to go onto a COS schedule<sup>59</sup> in the interim to  
8 accommodate both customers and Parties. While our primary position is that the  
9 Commission can and should approve the RIC and RAD in this proceeding; however, if this  
10 is not possible, we have provided an alternative option preserving customer options, for  
11 Parties to consider.

12 **Q. Even if the answer to the customers energizing were no, would PGE support a rule**  
13 **waiver for customers in the queue now, that regardless of when they energize, they**  
14 **should be eligible to participate in NLDA once all the terms are known?**

15 A. To the extent the RIC and RAD issues are moved into UM 2024 or another general  
16 investigation, we would support allowing the customers to energize and be served  
17 temporarily as COS until such time as the RIC and RAD issues are determined whether in  
18 this docket or another.

19 1. *Queue Implementation Issues*

20 **Q. What issues did Parties raise regarding the NLDA queue?**

21 A. Staff responds to our proposal to suspend the NLDA tariff filing to coincide with the  
22 investigation for the RIC and RAD. Staff states that customers in the queue cannot energize

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<sup>59</sup> PGE/200, Sims – Tinker/8.

1 and maintain their place queue position prior to the final determination of the NLDA tariff  
2 (i.e. once a customer energizes beyond construction needs, the customer would be deemed  
3 ineligible for NLDA).<sup>60</sup> As we stated earlier, Staff is opposed to our proposal to hold  
4 Schedule 689 in abeyance until there's a final decision made on the RIC and RAD charges.  
5 With a waiver of the NLDA rule for good cause, customers could energize and maintain  
6 eligibility. It is our position that this is fully within the Commissions authority and ability  
7 within this proceeding.

8 AWEC also responds to PGE's proposal from our reply testimony and states that a more  
9 fair and lawful approach would be for the NLDA tariff to be approved absent the RIC and  
10 RAD charges and for the queue participants to be able to take service under Schedule 689  
11 absent the RIC and RAD until such time those charges are approved.<sup>61</sup> Calpine provided no  
12 further input regarding the implementation of the NLDA queue and defers to their opening  
13 testimony as Calpine's current position on the matter.<sup>62</sup>

14 **Q. Do you agree with Staff's assertion that Schedule 689 cannot be held in abeyance until**  
15 **final decisions for the RIC and RAD are made?**

16 A. No. In fact, the Commission and the utility may agree to suspend an investigation by way  
17 of ORS 757.215 (2) which states that, "This section does not prevent the commission and  
18 the utility from entering into a written stipulation at any time extending any period of  
19 suspension."<sup>63</sup>

20 **Q. How do you respond to Staff and AWEC's positions regarding the NLDA queue?**

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<sup>60</sup> Staff/300, Gibbens/12.

<sup>61</sup> AWEC/200, Mullins/4.

<sup>62</sup> Calpine/200, Higgins/14.

<sup>63</sup> See ORS 757.215 (2).

1 A. Our position is that allowing eligible, queued customers to fully energize prior to the  
2 approval of the NLDA tariff (Schedule 689) would not delay construction and operation of  
3 queued customer facilities, and provide these customers an opportunity to evaluate the  
4 potential impacts associated with an approval of the RIC and RAD. PGE would support a  
5 limited initial waiver of the NLDA rule related to the load being new and incremental in  
6 order to provide customers the ability to commence service under COS, while retaining the  
7 choice to remain on COS or choose NLDA once the Commission makes a determination  
8 regarding the fundamental reliability and fairness issues raised.

9 **Q. What was the original intent of the NLDA queue?**

10 A. The original intent of the NLDA queue was to ensure that prospective NLDA customers  
11 would have the opportunity to provide their revocable notice of enrollment for service and  
12 have an opportunity to be included under PGE's NLDA cap amount of 119 MWa while  
13 Staff investigated the RIC and RAD through this docket. Additionally, the queue provided  
14 the Commission an ability to waive the rule-required one-year notice provision for the  
15 incremental load start date.<sup>64</sup>

16 **Q. Is PGE open to extending the duration of the queue to coincide with a potential new  
17 investigation for the RIC and RAD?**

18 A. Yes. We are open to extending the duration of the queue if a final determination for the RIC  
19 and RAD is not decided in this docket.

20 2. NLDA Cap Issues

21 **Q. What issues did Parties raise with regards to the NLDA cap?**

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<sup>64</sup> See OAR 860-038-0740.

1 A. Staff disagrees with our position, that the NLDA cap is a hard cap, and suggests that, should  
2 the cap be reached, enrollment for NLDA service and the ability to exceed the cap be made  
3 on a case-by-case basis.<sup>65</sup> Staff suggests that it is PGE’s obligation to ensure customers are  
4 notified of their ability to seek waivers of the cap so that customers are afforded sufficient  
5 time to file a waiver before being removed from the queue.<sup>66</sup>

6 AWEC questions the notion that PGE’s 119 MWa cap would in fact create a reliability  
7 concern in the Northwest, and further cites that the 20% transition adjustment charge for the  
8 first five years ensures that NLDA customers are paying their share of system costs until a  
9 general investigation for the RIC and RAD is complete.<sup>67</sup> Calpine argues that if customers  
10 take service under PGE’s “Daily Market Energy Option,” their loads should not be counted  
11 towards the NLDA program cap, then further argues that, “The Commission should be  
12 careful not to allow this aspect of the DA program to be converted to another green tariff,  
13 which has its own rules and caps being examined under Docket No. UM 1953.”<sup>68</sup>

14 **Q. Do you agree with Calpine’s recommendation to omit load from the NLDA cap if the**  
15 **customer is on PGE’s “Daily Market Energy Option”?**

16 A. No. Calpine’s proposal is not founded on any rules or orders by the Commission on how  
17 loads are to be evaluated for the purposes of DA caps. Therefore, customers taking load  
18 under PGE’s Daily Market Energy Option should be treated like any other load served by a  
19 third-party supplier (ESS).

20 **Q. Do you agree with Staff’s recommendation that PGE is obligated to inform customers**  
21 **of their right to seek a NLDA cap waiver?**

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<sup>65</sup> Staff/300, Gibbens/11.

<sup>66</sup> Id.

<sup>67</sup> AWEC/200, Mullins/5.

<sup>68</sup> Calpine/300, Higgins/13.



1 A. No. The intent of NLDA is to afford large sophisticated customers the ability to  
2 immediately choose their supply rather than subsequently enrolling in LTDA. Calpine even  
3 cites when referencing current and potential NLDA customers that, “These customers are  
4 sophisticated energy buyers that want control of the energy procurement and costs and have  
5 the wherewithal to assess the risks associated with their options.”<sup>69</sup> From our experience in  
6 working with current and potential DA customers, we’ve observed that these customers are  
7 very adept at understanding energy pricing, supply optionality, and understand how to  
8 leverage the DA rules to their advantage. We see no reason why PGE ought to be the  
9 conduit to interpret and inform customers on their potential opportunities to seek a waiver  
10 for NLDA given their advance understanding of energy markets and regulatory/tariff  
11 matters.

12 **Q. How do you respond to AWEC’s assertion that the 119 MWa of NLDA would not pose**  
13 **any reliability issues for PGE?**

14 A. We disagree with AWEC’s qualitative assertion. As we stated in our last round of  
15 testimony, we estimate that 373 MW of incremental capacity is needed to support the  
16 reliability needs of existing LTDA customers<sup>70</sup> which supports the outcomes as outlined by  
17 the Northwest Power and Conservation Council’s draft Resource Adequacy Assessment  
18 results included in PGE Exhibit 301.

19 **Q. Does PGE agree with the statement by AWEC that suggests that the NLDA transition**  
20 **adjustment of 20% of fixed generation will be sufficient to compensate for RA until a**  
21 **separate investigation for the RIC and RAD is complete.**

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<sup>69</sup> Calpine/200, Bass/3.

<sup>70</sup> PGE/200, Sims – Tinker/20.

1 A. No. The issue at hand is how to appropriately acquire and charge for capacity to ensure RA  
2 for our customers. Whether or not the transition adjustment covers costs associated with  
3 RA is inconsequential as we think of the customer, as a whole, during and past the point of  
4 the transition adjustment. The basis of the 20% transition adjustment does not specify what  
5 cost categories are included; however, as stated in our cover letter for Advice Filing No. 19-  
6 02, “The charge would be applied during all years of service on Schedule 689. During the  
7 first 60 months, the Customer pays transition adjustments that include 20% of the fixed  
8 generation cost of energy supply, and a RAD charge less the amount of the transition  
9 adjustment.”<sup>71</sup> As implied by our initial advice filing, the costs of RA may be covered by  
10 the transition adjustment; however, in the event that the transition adjustment is under-  
11 recovering costs associated with RA, COS customers would be subsidizing NLDA  
12 customers until the final determination of the RIC and RAD is made.

13 **Q. Do any Parties agree with any of PGE’s proposals regarding how load is measured**  
14 **against the NLDA cap?**

15 A. Yes. Staff agrees with our position that customer loads and NLDA eligibility be tied to the  
16 distribution facility design.

### C. The RIC

#### 17 I. RIC Pricing and Characteristics

18 **Q. Has PGE’s recommendation and position on for the RIC charge changed?**

19 A. No. The recycled claims of the Parties with regard to the RIC have been fully addressed in  
20 our earlier testimonies.

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<sup>71</sup> PGE Advice No. 19-02, at page 7.

1 **Q. Is the RIC duplicative of the RAD?**

2 A. No. We will not repeat the same arguments we have made in our previous testimony.  
3 However, we think it is worth noting that even if there were somehow overlap in the ability  
4 of capacity resources procured to provide RIC service, PGE’s above-outlined approach for  
5 determining the RAD would avoid any double charging through the functionalization of RA  
6 related costs to determine the RAD.

7 **Q. Does the Commission have the ability to approve the RIC?**

8 A. Yes. Despite parties’ claims, the RIC is clearly distinct from Energy Imbalance Service  
9 offered under Schedule 4R of PGE’s OATT. Additionally, arguments by the parties that the  
10 RIC is related to OATT service because it uses the information conveyed on transmission  
11 schedules is unsupported.<sup>72</sup> These schedules contain the ESS’s “projection of its hourly  
12 Electricity deliveries, measured in megawatt-hours (MWh) that are necessary to meet the  
13 aggregate hourly load of its Customers” and the ESS scheduling requirements are governed  
14 by Rule K of PGE’s retail tariff, as approved by the Commission.<sup>73</sup>

#### D. Other Issues

15 1. NLDA Draft Contract

16 **Q. What have Parties raised regarding the NLDA contract?**

17 A. Staff agrees with Calpine that the NLDA customer contract ought to be reviewed and  
18 approved in this docket.<sup>74</sup>

19 **Q. Does PGE agree with Staff’s position?**

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<sup>72</sup> AWEC/200, Mullins/15.

<sup>73</sup> PGE Rule B, page B-3, section 17.

<sup>74</sup> Staff/300, Gibbens/13.

1 A. No. The proposal seems premature and would seek to advance NLDA prior to addressing  
2 foundational system reliability and customer cost-risk fairness concerns. The drafting of a  
3 NLDA customer contract requires tariff decisions to be made in this docket before the  
4 drafting and sharing of PGE's proposed NLDA contract. PGE has responded to DRs and  
5 provided Parties with the LTDA customer contract as a best faith effort. We would expect  
6 the contract approach and terms to be similar. However, there are also differences.  
7 Following the decisions from this docket, and while different from the LTDA program  
8 which did not require advance Commission approval of the contract, we have no objection  
9 to filing the draft contract for review. The LTDA customer contract, attached as an exhibit,  
10 will be used as a starting template for the proposed NLDA customer contract.<sup>75</sup>

11 2. RPS Cost Recovery

12 **Q. Staff recommends deferring action on PGE's standard offer service proposal to a**  
13 **general rate case or separate investigation. Please comment.**

14 A. PGE is required to make at least one standard offer under Oregon law.<sup>76</sup> The current option  
15 is a daily market option for long term DA and PGE has at least one customer participating.  
16 While a customer is on the daily market option, the pricing is a Mid-Columbia market index  
17 which does not consider RPS value or attributes. The customer is being served with a  
18 supply product that is not compliant with the RPS, and because there is no RPS cost adder  
19 charged to the standard offer service customer, the cost to comply with the RPS for that  
20 customer would be subsidized by COS customers. When PGE first designed the daily  
21 market option for the LTDA program, the RPS did not exist. PGE identified this issue when

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<sup>75</sup> See PGE Exhibit 305.

<sup>76</sup> OAR 860-038-0250 (1).

1        considering the NLDA program. Thus, PGE proposed the second standard offer service to  
2        provide a long term RPS compliant product to NLDA participating customers. To provide a  
3        NLDA standard offer service option and be RPS compliant, PGE proposed the new long-  
4        term market option.

5        **Q. What would be the consequence of deferring action on the proposed standard offer**  
6        **service option?**

7        A. The consequence is that PGE would be forced to choose between complying with the  
8        Oregon RPS requirements or shifting costs to shareholders and COS customers.

#### IV. Conclusion

1 **Q. Please summarize PGE’s recommendation for the Commission.**

2 A. The scope of this investigation is to investigate the RIC and RAD charges, our long-term  
3 standard offer service and other policy items as raised in our advice filing for Schedule 689.  
4 The Commission can and should make a determination on the substantive issues raised in  
5 PGE’s application – namely whether all customers, whether cost of service or NLDA,  
6 should have a responsibility to support resource adequacy, and to fairly share in both the  
7 benefits and costs of maintaining a reliable electric system. The Commission may make a  
8 lasting decision from this record or adopt a provisional solution while Parties participate in a  
9 broad and far-reaching DA policy docket. Irrespective of this decision, it is imperative that  
10 the Commission protect the reliability of the electric system by including mechanisms that  
11 ensure large new loads contribute toward the necessary costs of securing capacity required  
12 to meet the system’s RA requirements. Any other outcome would unnecessarily threaten  
13 system reliability and unfairly burden cost of service customers with all reliability costs and  
14 risks.

## **List of Exhibits**

| <b><u>PGE Exhibit</u></b> | <b><u>Description</u></b>                                    |
|---------------------------|--|
| 301                       | Northwest Public Power Council’s RAAC Steering 2024 Adequacy |
| 302                       | UE 358 PGE DR 001 to Calpine Response                        |
| 303                       | UE 358 PGE DR 003 to Staff Response                          |
| 304                       | UE 358 PGE DR 006 to Calpine Response                        |
| 305                       | Long Term Direct Access Template                             |

# 2024 Resource Adequacy Assessment

## Resource Adequacy Advisory Committee Steering Committee Meeting

NW Power and Conservation Council

August 30, 2019

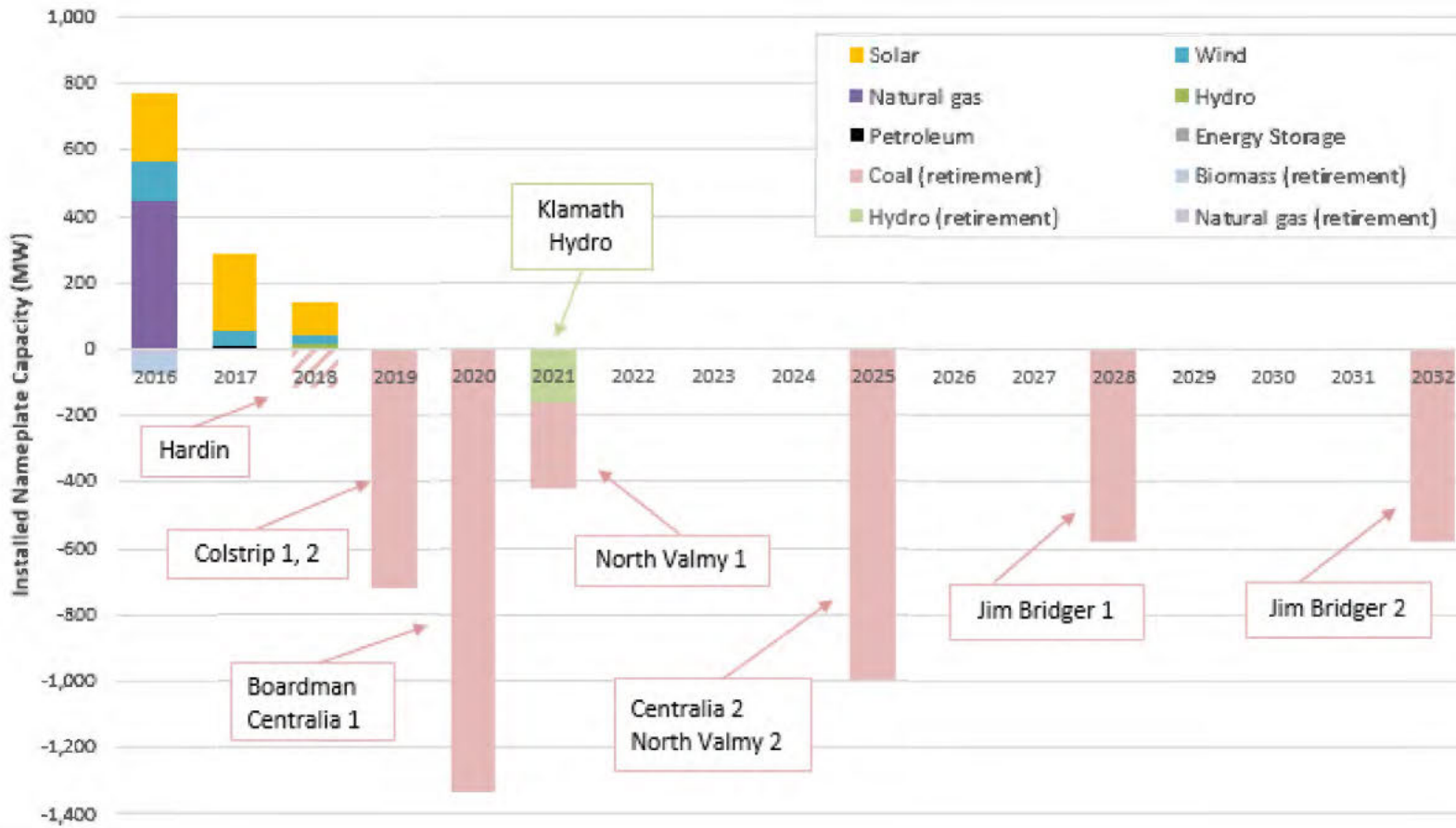


# Outline

- Projected Coal Retirements through 2032
- 2024 Reference and Early Coal Retirement Cases
- Classic GENESYS adequacy assessment
- Summary of enhancements in new GENESYS
- New GENESYS analyses
  - Single “bad” year dispatch comparison to classic GENESYS
  - Projections for RA assessment with new GENESYS
- Key issue – import availability

# Projected Coal Retirements<sup>1</sup> (3,357 MW)

Additions and Retirements since the Seventh Power Plan  
 (incl. announced planned retirements)

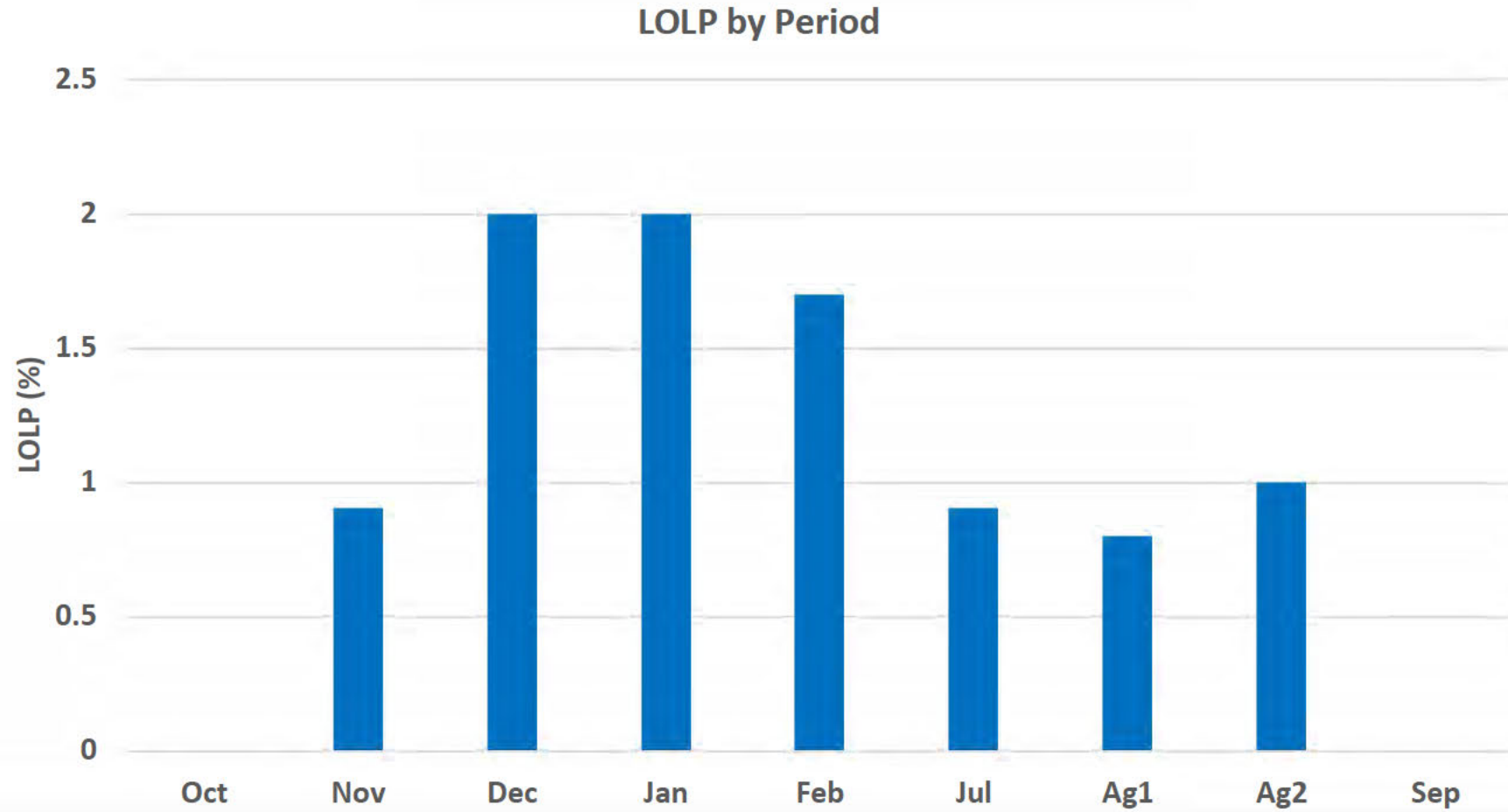


| Major Coal Plants Serving PNW | Ref Retire Date (EOY) | Early Retire Date |
|-------------------------------|-----------------------|-------------------|
| Hardin (119 MW)               | 2018                  | 2018              |
| Colstrip 1 (154 MW)           | 2019                  | 2019              |
| Colstrip 2 (154 MW)           | 2019                  | 2019              |
| Boardman (522 MW)             | 2020                  | 2020              |
| Centralia 1 (670 MW)          | 2020                  | 2020              |
| N Valmy 1 (127 MW)            | 2021                  | 2021              |
| N Valmy 2 (134)               | 2025                  | 2023              |
| Centralia 2 (670 MW)          | 2025                  | 2023              |
| Bridger 1 (530 MW)            | 2028                  | 2023              |
| Bridger 2 (530 MW)            | 2032                  | 2023              |
| Colstrip 3 (518 MW)           | TBD                   | TBD               |
| Colstrip 4 (681 MW)           | TBD                   | TBD               |
| Bridger 3 (530 MW)            | TBD                   | TBD               |
| Bridger 4 (530 MW)            | TBD                   | TBD               |

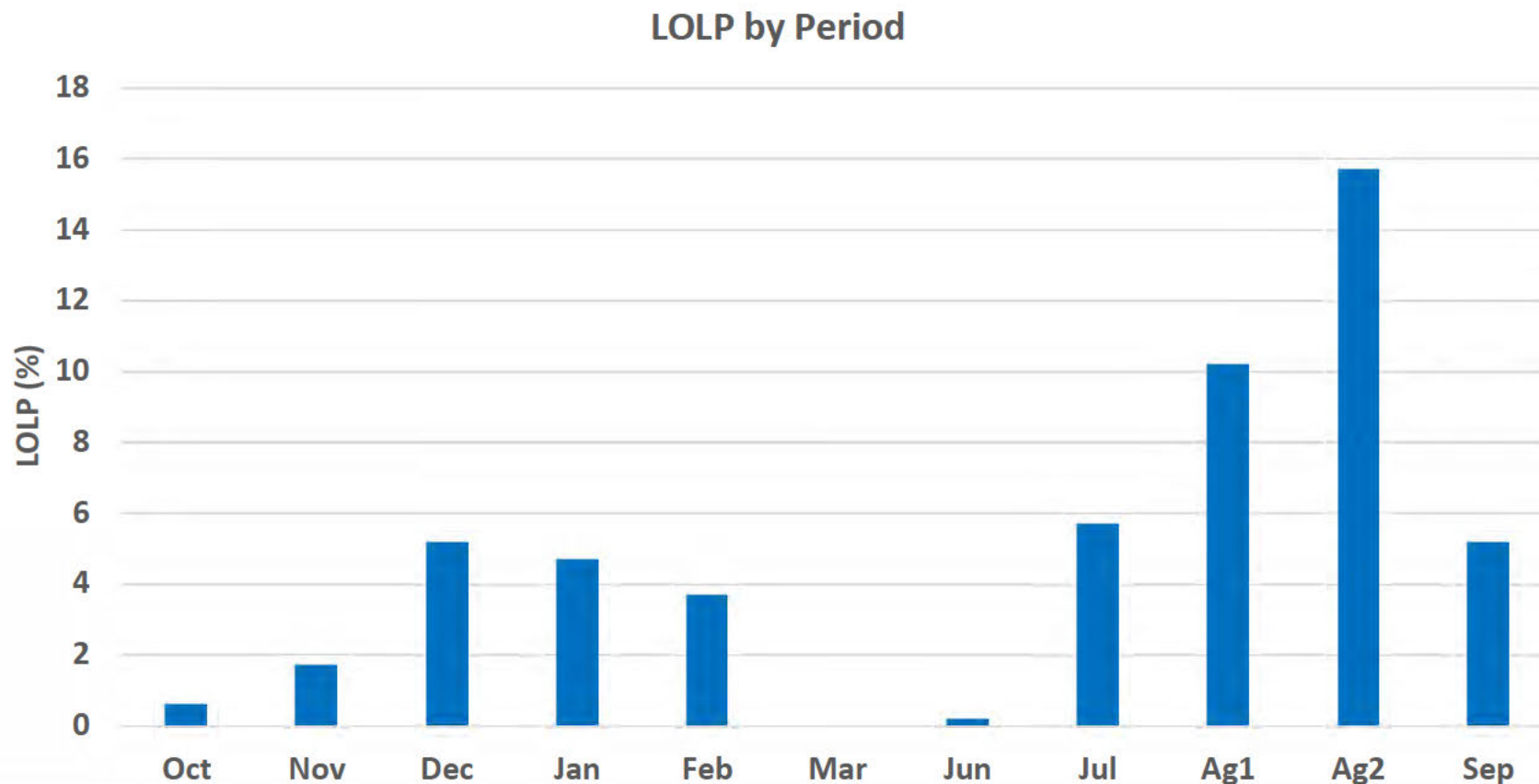
# 2021-24 Resource Adequacy Assessments

- **2021 LOLP = 7 to 8%**  
1,619 MW Retired Capacity (Hardin, Colstrip 1 and 2, Boardman, Centralia 1)
- **2022 LOLP = 7 to 8%**  
127 MW Retired Capacity (N Valmy 1)
- **2023 LOLP = 7 to 8%**  
No coal retirements
- **2024 LOLP = 8.2%** - with mostly winter shortfalls  
No coal retirements in reference case
- **2024 LOLP = 33%** - with both winter and summer shortfalls  
1,853 MW Early retirement case (Centralia 2, Bridger 1 and 2, N Valmy 2)

# Ref Case LOLP by Period



# Early Coal Retirement LOLP by Period<sup>1</sup>



# Future Uncertainties not Modeled Explicitly

- Out-of-region spot market supply
  - Region is connected to many other areas
  - Largest sharing between NW and SW
- Economic load growth
  - Non-temperature affected changes in long-term load
  - Economic growth or lack thereof
  - Possible immigration into region (climate change?)
  - Change in electrical use patterns (e.g. electric vehicles)

# Sensitivity to Markets and Load Growth

| LOLP (%)                                   | 1500 | 2000 | 2500 | 3000 | 3500 | 4500 | 5500             |
|--|------|------|------|------|------|------|------------------|
| High Load<br>(85 <sup>th</sup> Percentile) | 21.1 | 18.0 | 16.0 | 14.4 | 12.0 |      |                  |
| Medium Load                                | 12.5 | 10.2 | 8.2  | 6.9  | 5.2  | 3.8  | 2.9 <sup>1</sup> |
| Low Load<br>(15 <sup>th</sup> Percentile)  | 7.0  | 5.2  | 4.0  | 3.1  | 2.0  |      |                  |

<sup>1</sup>Because classic GENESYS only has spot market available in winter, increasing imports to 5500 MW eliminates all winter shortfalls but the summer problems remain.



# Sensitivity to Markets and Load Growth

## Early Coal Retirement Case

| LOLP (%)                                   | 2500 | 4500              | 6500 | 8500 |
|--|------|-------------------|------|------|
| High Load<br>(85 <sup>th</sup> Percentile) |      |                   |      |      |
| Medium Load                                | 33.0 | 26.5 <sup>1</sup> |      |      |
| Low Load<br>(15 <sup>th</sup> Percentile)  |      |                   |      |      |

<sup>1</sup>The increased spot market availability did not reduce the overall LOLP much because most of the shortfalls occur in summer and the market is only available in winter.

# New GENESYS Features

1. Explicit modeling of out-of-region resources and loads
2. Hourly simulation of individual hydro projects
3. Multiple NW node configuration (as opposed to 2-node)
4. Unit commitment
5. Dynamic allocation of balancing reserves
6. Forecast error effects (true-up stage)

# Effects of New Features on LOLP

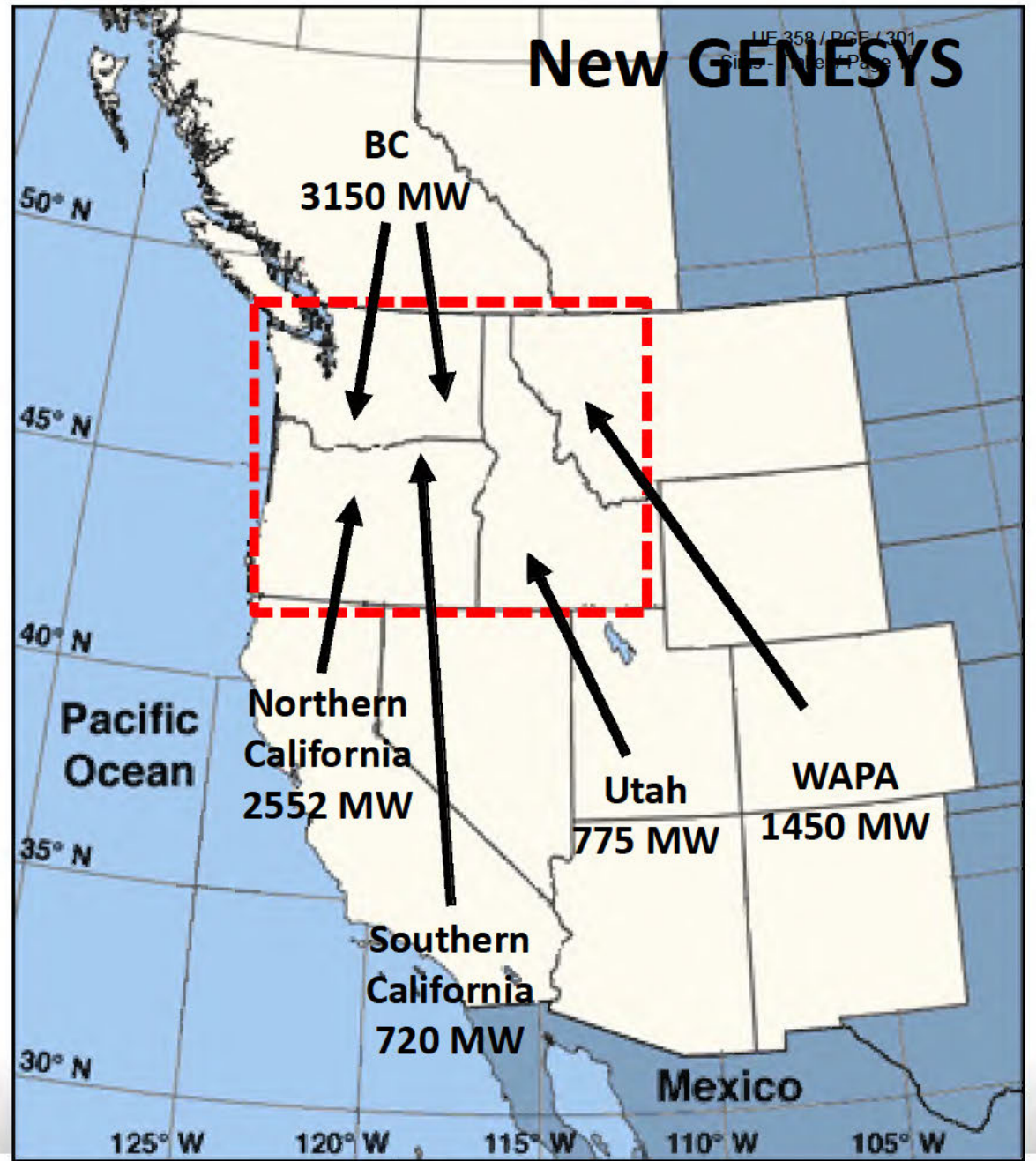
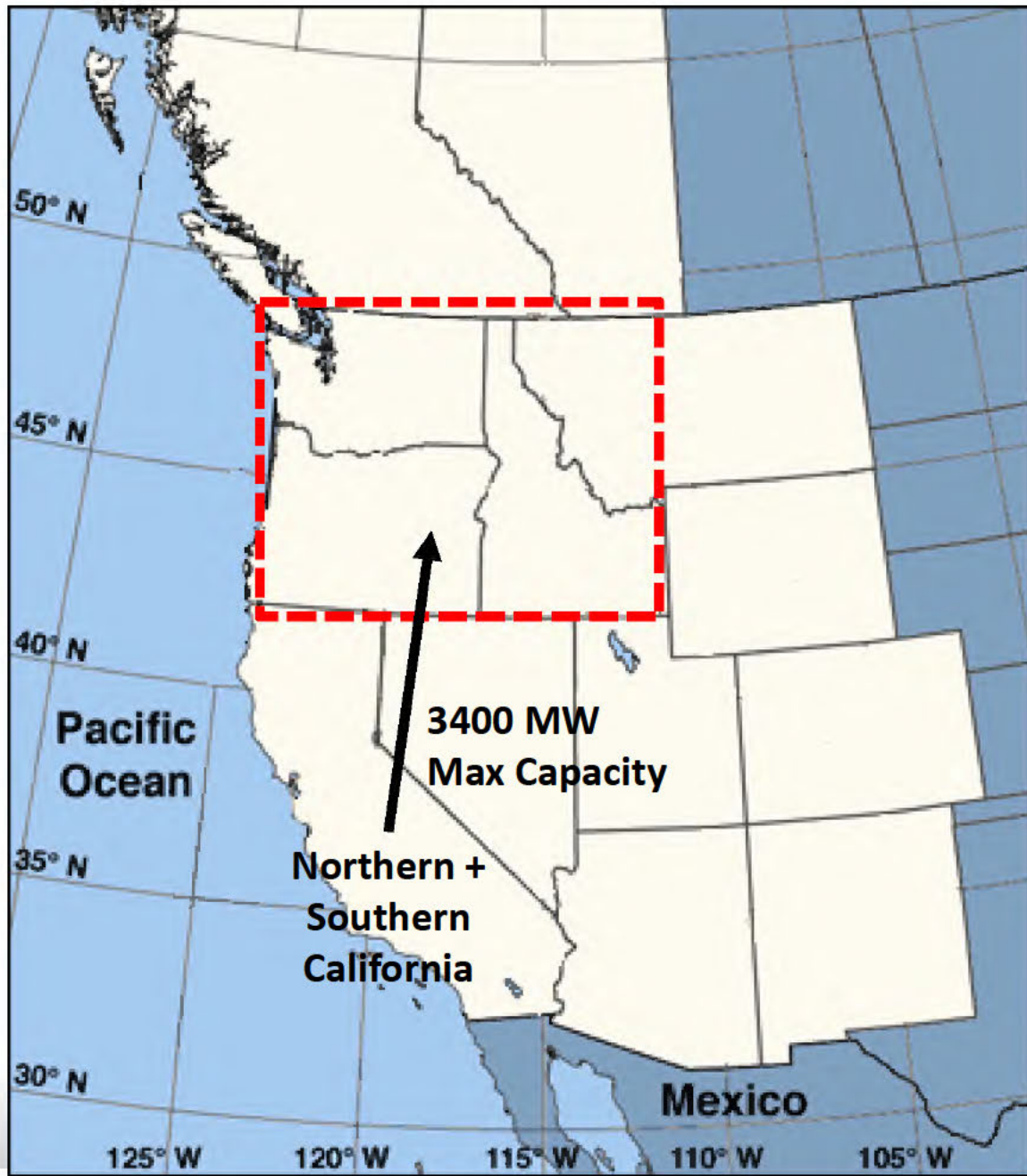
- 1. Out-of-region supply**  
Will significantly lower LOLP  
Market supply increases from 2500 MW to over 8,000 MW
- 2. Hourly hydro simulation**  
Impact unclear (may lower LOLP if classic GENESYS sustained-peaking capacity approximations are conservative)
- 3. Multiple NW nodes**  
Likely to **increase LOLP** due to potential congestion issues
- 4. Unit commitment**  
Likely to **increase LOLP** (unit commitment in classic GENESYS was limited)
- 5. Dynamic balancing reserves**  
Likely to **increase LOLP** (classic GENESYS only modeled static hydro reserves)
- 6. Forecast error**  
Likely to **increase LOLP** (if balancing reserves are properly assessed)

# Incorporating Market Imports

- **Classic GENESYS**
  - Max 2500 MW for Spot Market – during hour of need **winter only**
  - Max 3000 MW for Purchase Ahead – during off-peak hours ahead of future shortage
  - Max 3400 MW total import (spot + purchase ahead)
  - Only from California (as a surrogate for all imports)
  - Priced higher than any NW resource
- **New GENESYS**
  - Simulates dispatch of out-of-region resources & loads, dynamically assesses market size
  - From all WECC regions that have interconnections to the NW
  - Price reflective of resource type
  - Max 8600 MW total import (limited by transmission capacity)
  - Max import availability can be much higher than transmission limits
  - Availability greater in winter but some market supply in summer also

# Transmission Capacity for Imports

| From  | To        | Min Transfer Cap <sup>1</sup> (MW) |
|---|-----------|------------------------------------|
| <b>New GENESYS Assumptions (to potential market sources only<sup>1</sup>)</b> |           |                                    |
| Northern California   | Pac West  | 2552                               |
| LADWP   | BPAOR     | 720                                |
| BC  | PS North  | 2762                               |
| BC  | Avista    | 388                                |
| WAPA  | NW        | 1450                               |
| Pac Utah  | Pac Idaho | 775                                |
| <b>Total</b>  |           | <b>8647</b>                        |
| <b>Current GENESYS Assumption</b>   |           |                                    |
| California  | PNW       | <b>3400</b>                        |



# Classic vs. New GENESYS

Caveat: The beta version of the new model is functional and is providing reasonable early results. However, it is still in the second phase of vetting and is being refined for its hourly simulations. It is not yet at a level to confidently run full RA studies.

Test: Compare hourly simulated dispatch for the 2024 reference case using 1950 temperatures and 2001 hydro conditions (i.e. a “bad” year)

- **Classic GENESYS**
  - 8 curtailments in Jan and Feb (highest single-hour curtailment 6400 MW)
  - Max imports 3400 MW
  
- **New GENESYS**
  - No curtailments
  - Max import up to 8650 MW

# 2024 Resource Adequacy Assessment

- **Classic GENESYS**
  - 8.2% LOLP – reference case
  - 33% LOLP – early coal retirement case
  
- **New GENESYS<sup>1</sup>**
  - 0% Inferred LOLP<sup>1</sup> – reference case
  - 0.5% Inferred LOLP<sup>1</sup> – early coal retirement case

<sup>1</sup>The New GENESYS has NOT yet been fully vetted for use to assess resource adequacy. However, we can infer what the LOLP might be by using the curtailment record from the classic GENESYS and applying a maximum of 8650 MW of imports year round.



# Sensitivity to Markets and Load Growth

## Early Coal Retirement Case

| LOLP (%)                                   | 2500 | 4500 | 6500 <sup>1</sup> | 8500 <sup>1</sup> |
|--|------|------|-------------------|-------------------|
| High Load<br>(85 <sup>th</sup> Percentile) |      |      |                   |                   |
| Medium Load                                | 33.0 | 26.5 | 0.9               | 0.3               |
| Low Load<br>(15 <sup>th</sup> Percentile)  |      |      |                   |                   |

Implied LOLP  
from New  
GENESYS is 0.5%



<sup>1</sup>For these scenarios, the specified import amounts were available for all months. They were designed only as a test to compare to the New GENESYS and are NOT intended to be a part of the adequacy assessment.

# 2024 Resource Adequacy Assessment

- Until the new GENESYS is fully vetted, the classic GENESYS model will be used for assessments
- However, the new model's simulation of out-of-region resources and loads indicates that import assumptions in the classic model may be understated
- This warrants further analysis of how much market supply, from all interconnected regions, the NW can reliably count on during conditions when resources may be scarce WECC-wide

# Market Supply Assessments

- An Energy GPS report (attached) indicated that import availability may be much greater than 2500 MW but warned that “limitations on Aliso Canyon storage withdrawals will very likely limit available exports to the Pacific Northwest well below the 2,500 MW planning number.”
- Records from this year’s ACDC intertie loading data (attached) show that imports in some February hours were between 2500 and 3100 MW.
- Import availability from other interconnected regions has not been extensively investigated.

# Proposed Action Items

1. More in-depth analysis of out-of-region market supplies from all interconnected regions is warranted
2. Analyses of transmission transfer capabilities and reliability is also warranted
3. Continue to vet the new GENESYS
4. Add the ability to limit imports in the new GENESYS
5. Base the 2024 Resource Adequacy Assessment on the classic GENESYS model results
6. Others?

**Portland General Electric Data Request No. 01:**

Does Calpine Energy Solutions, LLC conduct long-term resource planning for the contracted loads it serves? If yes, please provide copies of the last five years of resource plans. If no, please explain why Calpine Energy Solutions, LLC does not conduct long-term resource planning.

**Calpine Energy Solutions, LLC's Response:**

Calpine Energy Solutions, LLC ("Calpine Solutions") objects with respect to the request to supply "copies of the last five years of resource plans" to Portland General Electric Company ("PGE") on the grounds of commercial harm that could be caused by providing such information to PGE. PGE has significant market power in the region and Calpine Solutions is a direct competitor with PGE in the retail generation market. As an electricity service supplier, Calpine Solutions' market positions, as well as its strategies to serve its contracted and expected loads are highly commercially sensitive information, and disclosure of this information to PGE could cause significant commercial harm to Calpine Solutions.

Without waiving its objection, Calpine Solutions currently conducts regular long-term supply planning associated with compliance for the State of Oregon's Renewable Portfolio Standard ("RPS") and for risk management purposes. The overall approach is to identify supply and load imbalances associated with both known customer contracted load, as well as forecasted customer load and the timeframe and amount of future supply and load imbalances. The commercial and regulatory supply obligations are currently analyzed through the year 2027.

Attached as Exhibit DR 01 is an illustrative example of Calpine Energy Solutions, LLC's RPS Position Summary used for RPS compliance planning purposes, which demonstrates the type of data and information that Calpine Solutions includes in its long-term supply planning, without providing any actual data that could harm Calpine Solutions' commercial position if disclosed to PGE.

UE 358 – PUC Response to PGE Data Request  
Page 1

Date: August 1, 2019

TO:

KARLA WENZEL  
MANAGER, PRICING AND TARIFFS  
121 SW SALMON ST, 1WTC0702  
PORTLAND OR 97204  
[pge.opuc.filings@pgn.com](mailto:pge.opuc.filings@pgn.com);

FROM: Scott Gibbens  
Senior Economist  
Energy Rates, Finance and Audit Division

**OREGON PUBLIC UTILITY COMMISSION**  
**Docket No. UE 358 - PGE Data Request filed July 18, 2019**

**Data Request No 03:**

3. See Gibbens/14, line 11: Please provide the price impact analysis which shows the impacts to “direct access rates”

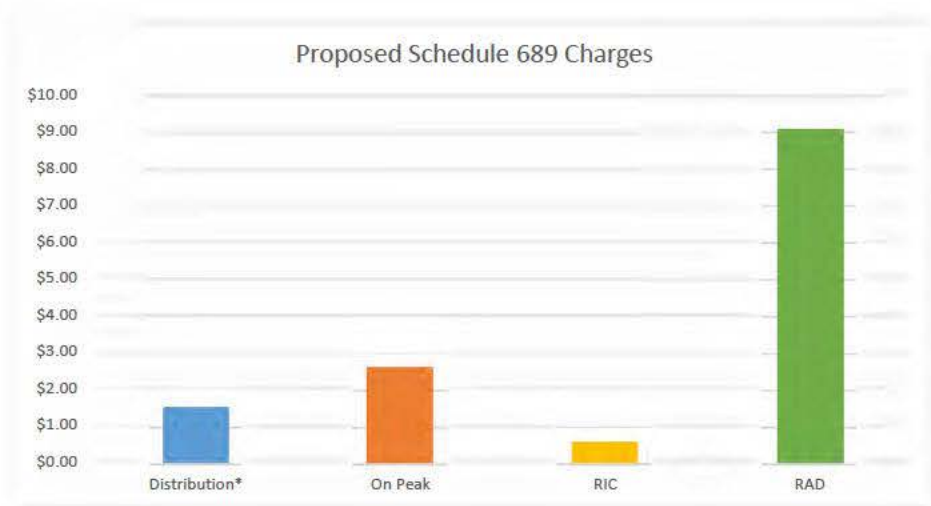
**Staff Response No 03:**

3. Please see attachment Staff Response to PGE DR No. 3A.

Schedule 489/689

|               | Secondary | Primary |
|---------------|-----------|---------|
| Distribution* | \$1.53    | \$1.49  |
| On Peak       | \$2.61    | \$2.53  |
| RIC           | \$0.58    | \$0.58  |
| RAD           | \$9.08    | \$9.08  |
| Total         | \$13.80   | \$13.68 |
| RAD%          | 66%       | 66%     |

\*First 4000 kW

















**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.

[Customer name]

AND

PORTLAND GENERAL ELECTRIC COMPANY

COST-OF-SERVICE OPT-OUT AGREEMENT

UNDER SCHEDULE(S) **\*\* (choose only the schedule(s) applicable to Customer under this Agreement)\*\* 485/489/490** (5-Year)

SEPTEMBER \_\_\_\_, 2018

This Cost-Of-Service Opt-Out Agreement ("Agreement") is between \_\_\_\_\_ ("Customer") and PORTLAND GENERAL ELECTRIC COMPANY ("PGE"). This Agreement is based on Customer's election to take service under the terms and conditions of Schedule(s) **[(choose only the schedule(s) applicable to Customer under this agreement)]** 485/489/490, as such Schedule(s) may be modified, amended, or succeeded from time to time. PGE and Customer are hereinafter sometimes referred to individually as "Party" and collectively as "Parties."

The Parties agree as follows:

1. Term and Termination of Agreement

Customer is electing to take service under the terms and conditions of Schedule(s) **[(choose only the schedule(s) applicable to Customer under this agreement)]** 485/489/490, as such Schedule(s) may be modified, amended, or succeeded from time to time following approval or equivalent action by the Oregon Public Utility Commission (hereinafter referred to as "Applicable Schedule(s)").

This Agreement shall remain in effect for a minimum term of five years from 12:01 a.m. January 1, 2019 to 11:59 p.m. December 31, 2023. Thereafter, it shall extend from year-to-year until notice is given to PGE, by Customer, and this Agreement is terminated three years later, on the anniversary date. Whether Customer wishes to terminate the Agreement at the end of the five year term or at a subsequent anniversary date, and regardless of which rate schedule Customer is being served under at the time, Customer must in all circumstances give PGE not less than 3 years advance written notice of its intent to terminate this Agreement. Upon receipt by PGE, such notice of intent to terminate this Agreement shall be binding on the Parties. At the time of termination of this Agreement, Customer will be considered a "new" Customer for purposes of determining available service options.

2. Service

PGE shall furnish to Customer, at each Service Point described in this Agreement, sixty-hertz alternating current of such phase and voltage as PGE may have available, subject to the General Rules and Regulations of PGE's current tariff, which tariff is typically available on PGE's website at: [www.portlandgeneral.com/our-company/regulatory-documents/tariff](http://www.portlandgeneral.com/our-company/regulatory-documents/tariff).

3. Location(s) to be Served

Pursuant to this Agreement, PGE shall furnish service consistent with the Applicable Schedule, at the Customer location(s) listed on Exhibit A, which exhibit is attached hereto and incorporated by reference.



If this box is initialed by Customer, Customer represents that: 1) it has one or more cost of service opt-out agreements in place with PGE; 2) the previously enrolled Service Point IDs ("SPIDs") continue to sum to at least 1 aMW; and 3) the location(s) to be served under this Agreement is an/are additional SPID(s) that does not/do not currently have a usage pattern demonstrating usage for a full 12 months of at least 8,760,000 kWh (1 MWa), however, each



Service Point listed in this Agreement meets the 250 kW Facility Capacity threshold requirement, and is thereby eligible, under the Applicable Schedule, to be opted-out of cost-of-service as an “additional location”.

**4. Description of Service Point(s)**

The Service Point(s) for the service(s) provided under this Agreement is (are) specifically described as:

**5. Pricing and Payment**

Customer agrees to pay all applicable rates and charges specified in the Applicable Schedule(s), including but not limited to, those rates and charges related to Customer’s election with regard to Energy Supply, in accordance with the terms and conditions of the Applicable Schedule(s) and Tariff Rules. Following receipt of bill, Customer shall make such payments to PGE when due.

**6. Customer Address**

All bills and notices issued under or pursuant to this Agreement shall be sent to Customer at the following address:

**7. Successors and Assigns**

Customer may assign this Agreement to a third party or a successor in interest as long as (a) in PGE’s reasonable judgment, such third party’s or successor’s creditworthiness and ability to perform Customer’s obligations outlined in this Agreement are at least as good as that of Customer; (b) Customer provides written documentation to PGE that substantiates the assignment; (c) the assignee or successor agrees to act in good faith to document his/her agreement to assume, be bound by and perform Customer’s duties and obligations pursuant to the same terms and conditions as those contained in this Agreement (e.g. agrees to the execution of a Novation Agreement or a new agreement in their name containing the same terms and conditions); and (d) the assignee or successor agrees to timely complete his/her enrollment for Energy Supply.

**8. Modification of Previous Agreements**

Any other agreements pertaining to Customer’s opting out of PGE’s Cost of Service pricing for the location(s) and Service Point(s) designated in this Agreement are hereby superseded and replaced by this Agreement. For the avoidance of doubt, this Agreement is not intended to alter or supersede any agreement for Minimum Load Service, Alternate Service, or Dispatchable Standby Generation that may exist between the Parties.

**9. Waivers and Other Conditions**

For the duration of this Agreement, Customer waives any rights to receive Electricity (as defined in Rule B of PGE's tariff) from PGE under cost-of-service rates, and waives any claim against PGE under OAR 860-021-0010(5) based in any way on Customer's election of service under the Applicable Schedule(s). In connection with these waivers and the taking of service under the Applicable Schedule(s), by signing this Agreement Customer also acknowledges and agrees to abide by all of the Special Conditions listed in Schedule(s) **[(choose only the schedule(s) applicable to Customer under this agreement)\*\* 485/489/490]**, as such may be modified, amended, or succeeded from time to time following approval or equivalent action by the Oregon Public Utility Commission.

#### 10. Representations and Warranties

- a) Representations and Warranties of PGE. PGE represents and warrants to Customer that:
- i. it has the full right, power and authority to enter into this Agreement, to grant Customer the rights set forth herein, and to perform its obligations hereunder;
  - ii. the execution of this Agreement by the individual whose signature is set forth at the end of this Agreement, and the delivery of this Agreement by PGE, have been duly authorized by all necessary action on the part of PGE; and
  - iii. this Agreement, once executed and delivered by PGE, constitutes the legal, valid and binding obligation of PGE, enforceable against PGE in accordance with its terms.
- b) Representations and Warranties of Customer. Customer represents and warrants to PGE that:
- i. it has the full right, power and authority to enter into this Agreement and to perform its obligations hereunder;
  - ii. the execution of this Agreement by the individual whose signature is set forth at the end of this Agreement, and the delivery of this Agreement by Customer, have been duly authorized by all necessary action on the part of Customer;
  - iii. the execution, delivery and/or performance of this Agreement by Customer will not violate, conflict with, require consent under or result in any breach or default under (i) any applicable law or PGE tariff, including but not limited to Schedules 135 and 203, or (ii) with or without notice or lapse of time or both, any of the provisions of any contract or agreement to which it is a party or to which any of its material assets are bound ("Customer Contracts"); and
  - iv. this Agreement, once executed and delivered by Customer (and assuming due authorization, execution and delivery by PGE), constitutes the legal, valid and binding obligation of Customer, enforceable against Customer in accordance with its terms.

- c) No other Representations or Warranties. **EXCEPT FOR THE EXPRESS REPRESENTATIONS AND WARRANTIES CONTAINED IN THIS SECTION and SECTION 3 (IF THE BOX IN SECTION 3 IS INITIALED, SIGNIFYING IT IS APPLICABLE), (A) NEITHER PARTY TO THIS AGREEMENT, NOR ANY OTHER PERSON ON SUCH PARTY'S BEHALF, HAS MADE OR MAKES ANY EXPRESS OR IMPLIED REPRESENTATION OR WARRANTY, EITHER ORAL OR WRITTEN, WHETHER ARISING BY LAW, COURSE OF DEALING OR OTHERWISE, ALL OF WHICH ARE EXPRESSLY DISCLAIMED, AND (B) EACH PARTY ACKNOWLEDGES THAT IT HAS NOT RELIED UPON ANY REPRESENTATION OR WARRANTY MADE BY THE OTHER PARTY, OR ANY OTHER PERSON ON SUCH PARTY'S BEHALF, EXCEPT AS SPECIFICALLY PROVIDED IN THIS SECTION AND SECTION 3 (IF THE BOX IN SECTION 3 IS INITIALED, SIGNIFYING IT IS APPLICABLE) OF THIS AGREEMENT.**

11. Disclaimer of Consequential Damages

**NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS AGREEMENT, AND EXCEPT TO THE EXTENT REQUIRED BY LAW, PGE SHALL NOT BE LIABLE TO CUSTOMER FOR ANY LOST OR PROSPECTIVE PROFITS OR ANY OTHER SPECIAL, PUNITIVE, EXEMPLARY, CONSEQUENTIAL, MORAL, INCIDENTAL OR INDIRECT LOSSES OR DAMAGES (IN TORT, CONTRACT OR BASED ON ANY OTHER LEGAL OR EQUITABLE THEORY) UNDER OR IN RESPECT OF THIS AGREEMENT, WHETHER OR NOT ARISING FROM PGE'S SOLE, JOINT OR CONCURRENT NEGLIGENCE AND WHETHER OR NOT PGE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.**

12. Jurisdiction and Venue

Subject first to the venue, jurisdiction, and appeals priority of the PUC, if applicable, any judicial action or proceeding seeking to enforce any provision of this Agreement, or based on any right arising out of this Agreement, shall be brought in the Multnomah County Circuit Court of the State of Oregon and each of the Parties irrevocably consents to the jurisdiction of such court (and of the appropriate appellate court) in any such action or proceeding and waives any objection to such venue.

13. Miscellaneous

Except as provided for in Section 3 above, location(s) to be served and Service Point(s) shall not be added or removed during the term of this Agreement. Notwithstanding the foregoing, Service Point(s) may be removed, provided all of the following criteria are satisfied:

- a) The SPID is the subject of a purchase by an entity **other than** one controlled by, controlling, or under common control with Customer;
- b) PGE grants its consent to the removal of the SPID during the term, as well as the assignment and delegation under Section 7 to the purchasing entity;
- c) The Customer executes an assignment and delegation to the purchasing entity;
- d) The purchasing entity timely completes his/her enrollment for Energy Supply; and
- e) The purchasing entity contractually assumes all rights and all obligations contemplated under this Agreement with respect to the purchased SPID, by executing and delivering to PGE all documents and/or instruments as PGE deems necessary to document such agreement by the purchasing entity.

Except as outlined in the foregoing paragraph and for other modifications which result from changes approved by the Oregon Public Utility Commission in the applicable tariff provisions referenced and incorporated herein, no other modification of this Agreement shall be valid unless made in writing and signed by PGE and Customer.

No waiver of any provision of this Agreement shall be valid unless made in writing by the waiving Party, and no such waiver shall be deemed a waiver of compliance with any other provisions or conditions of this Agreement.

It is a condition of this Agreement that Customer continues to meet applicable statutory requirements and the requirements of PGE's Applicable Schedule(s) during the term of this Agreement. For the avoidance of doubt, Customer is expected to cease any current participation, and refrain from future participation, in any PGE program or pilot that would i) violate a statute, rule or Order of the OPUC, or ii) prohibit dual enrollment, as of the time and date Customer begins taking service under Schedule 485, 489, or 490. If, at any time during the term of this Agreement, Customer should fail to satisfy this condition, PGE shall have the right to terminate this Agreement and/or seek all such remedies that may be available to it under the law and/or in equity. To the extent the right to terminate is exercised by PGE, Customer will be considered a "new" Customer for purposes of determining available service options.

This Agreement and the services, rates, terms and conditions described in this Agreement, or incorporated by reference, are subject to all changes in applicable tariffs and all lawful orders of the Oregon Public Utility Commission.

**[SIGNATURES ON FOLLOWING PAGE]**

**IN WITNESS WHEREOF**, the undersigned Parties have executed this Agreement this \_\_\_\_ day of September, 2018.

\_\_\_\_\_  
(Company Name)

By: \_\_\_\_\_  
(Signature)

\_\_\_\_\_  
(Printed Name and Title of Signatory Party)

\_\_\_\_\_  
(Date)

**PORTLAND GENERAL ELECTRIC COMPANY**

By: \_\_\_\_\_  
(Signature)

\_\_\_\_\_  
(Printed Name and Title of Signatory Party)

\_\_\_\_\_  
(Date)

Approved as to rates \_\_\_\_\_