

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: <u>pge.opuc.filings@pgn.com</u>.

Sincerely,

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

<sup>&</sup>lt;sup>1</sup> Staff/300, Gibbens/2.

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

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

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

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

<sup>&</sup>lt;sup>2</sup> ORS 469A.052.

<sup>&</sup>lt;sup>3</sup> AWEC/200, Mullins/4.

<sup>&</sup>lt;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 <sup>5</sup> Calpine/300, Higgins/2.

 $<sup>^{\</sup>circ}$  Calpine/300, Higgins/2.

<sup>&</sup>lt;sup>6</sup> Calpine/200, Higgins/9.

<sup>&</sup>lt;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 AdequacyQ. Why should the Commission consider impacts on RA when making a determination on PGE's NLDA filing?

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

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

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

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

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

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

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

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

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

<sup>&</sup>lt;sup>9</sup> Calpine/200, Bass/4.

<sup>&</sup>lt;sup>10</sup> CUB/100, Jenks/3.

<sup>&</sup>lt;sup>11</sup> Calpine/300, Higgins/2.

<sup>&</sup>lt;sup>12</sup> Id.

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

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

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

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

<sup>&</sup>lt;sup>13</sup> Staff/300, Gibbens/4.

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

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

<sup>&</sup>lt;sup>16</sup> Calpine/200 Bass/4.

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

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

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

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#### Q. Does PGE support this procedural recommendation?

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

<sup>17</sup> See PGE Exhibit 301. <sup>18</sup> Staff/300, Gibbens/4.

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

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

Q. Should the Commission choose to review PGE's proposed capacity charges in a general DA investigation, has PGE proposed an alternative approach that does not 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

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

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

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

<sup>&</sup>lt;sup>19</sup> Staff/100, Gibbens/10.

<sup>&</sup>lt;sup>20</sup> Calpine/300, Higgins/4.

<sup>&</sup>lt;sup>21</sup> Calpine/300 Higgins/7.

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

### Q. What are the additional reasons Parties have given for the NLDA tariff being

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#### approved without the RIC and the RAD?

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

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

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

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

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

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

#### 8 <u>1. Supplying Resource Adequacy</u>

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

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

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#### 0 Q. What are the Parties' positions on the supply of RA and the need for the RAD?

<sup>&</sup>lt;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>&</sup>lt;sup>24</sup> Calpine/200, Bass/4.

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

<sup>&</sup>lt;sup>26</sup> Id.

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

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

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

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

<sup>&</sup>lt;sup>27</sup> Id.

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

<sup>&</sup>lt;sup>30</sup> CUB/100, Jenks/17.

<sup>&</sup>lt;sup>31</sup> Calpine/200, Bass/3.

<sup>&</sup>lt;sup>32</sup> *Id*.

<sup>&</sup>lt;sup>33</sup> Id.

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

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

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

34 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>&</sup>lt;sup>37</sup> Calpine/200, Bass/4

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

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#### 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?

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

<sup>38</sup> Id.

<sup>&</sup>lt;sup>39</sup> See PGE Exhibit 302.

<sup>&</sup>lt;sup>40</sup> Calpine/200, Bass/5.

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

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

<sup>&</sup>lt;sup>43</sup> Calpine/200, Bass/8.

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

2 How do you respond?

A. AWEC relies on FERC Order 890 which allowed certain types of contracts to be designated 3 as network resources for purposes of procuring network transmission service to deliver to 4 load within a balancing authority. FERC found that, 5 the inclusion of a 'make whole' LD provision...does not disqualify that 6 7 agreement from being designated as a network resource. However, other types of LD provisions may create incentives that are incompatible with the firmness of a 8 power purchase agreement....Thus, as of the effective date of the Final Rule, 9 power purchase agreements designated as network resources may only contain 10 LD provisions that are of the 'make whole' type.<sup>45</sup> 11 As can be observed above, FERC did not comment on the contribution to RA from firm LD 12 contracts. Rather, FERC provided clarification regarding what resources may qualify to be 13 a designated network resource for use of network transmission. Even if FERC had directly 14 linked designated network resources with RA, as of the date of filing this testimony, PGE 15 16 and BPA are the only two entities with load in the PGE BAA that have designated network resources shown on PGE's OASIS. 17 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 over their electricity supply (including the associated risks and benefits), and RA is a 20

- component of this supply."<sup>46</sup> However, it is clear that RA is not a component of supply 21
- derived from unspecified sources in the short-term wholesale energy market. Additionally, 22 the obligation of PGE to provide service to all loads within the balancing authority 23 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>&</sup>lt;sup>45</sup> FERC Order No. 890, page 867, paragraph 1455.

<sup>&</sup>lt;sup>46</sup> AWEC/200, Mullins/9.

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

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

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

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

<sup>&</sup>lt;sup>47</sup> AWEC/201, Mullins/6.

 $<sup>^{48}</sup>$  Id.

<sup>&</sup>lt;sup>49</sup> AWEC/200, Mullins/10.
<sup>50</sup> See PGE Exhibit 303.

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

13 2. Pricing and Functionalization

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

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

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

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

<sup>&</sup>lt;sup>51</sup> PGE's 2019 IRP, page 125.

further establishing the guiding principles of PGE's proposed functionalized RA costs.
 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.
22	0	Plassa raview the process to determine the RAD charge

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:

- Establish the revenue requirement;
- Allocate (or functionalize) the revenue requirement by category (e.g. generation,
   distribution, transmission, and RA);
  - C

6

7

Conduct a rate spread study to apportion the functionalized categories of costs to each 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?

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

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

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

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

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

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

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

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

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

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

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

17 <u>3.</u> RAD Alternatives

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

A. Yes. In its reply and rebuttal testimony Staff discussed the concept of "self-supply" of RA 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

<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.

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

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

 <sup>&</sup>lt;sup>54</sup> Calpine/100 Higgins/9 and Calpine/300 Higgins/7.
 <sup>55</sup> Calpine/200, Bass/2.

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

<sup>&</sup>lt;sup>57</sup> See PGE Exhibit 304.

<sup>&</sup>lt;sup>58</sup> PGE/200 Sims - Tinker/25-26.

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

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

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

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

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

#### **B.** NLDA Queue and Program Cap

### **Q.** Are there any customers in the queue that have already energized such that they would

18

#### not be eligible under Commission rules?

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

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

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

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

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

- 19 <u>1. Queue Implementation Issues</u>
- 20 Q. What issues did Parties raise regarding the NLDA queue?
- A. Staff responds to our proposal to suspend the NLDA tariff filing to coincide with the investigation for the RIC and RAD. Staff states that customers in the queue cannot energize

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

and maintain their place queue position prior to the final determination of the NLDA tariff 1 (i.e. once a customer energizes beyond construction needs, the customer would be deemed 2 ineligible for NLDA).<sup>60</sup> As we stated earlier, Staff is opposed to our proposal to hold 3 Schedule 689 in abeyance until there's a final decision made on the RIC and RAD charges. 4 With a waiver of the NLDA rule for good cause, customers could energize and maintain 5 eligibility. It is our position that this is fully within the Commissions authority and ability 6 within this proceeding. 7 AWEC also responds to PGE's proposal from our reply testimony and states that a more 8 fair and lawful approach would be for the NLDA tariff to be approved absent the RIC and 9 RAD charges and for the queue participants to be able to take service under Schedule 689 10 absent the RIC and RAD until such time those charges are approved.<sup>61</sup> Calpine provided no 11 further input regarding the implementation of the NLDA queue and defers to their opening 12 testimony as Calpine's current position on the matter.<sup>62</sup> 13 Q. Do you agree with Staff's assertion that Schedule 689 cannot be held in abeyance until 14 final decisions for the RIC and RAD are made? 15 A. No. In fact, the Commission and the utility may agree to suspend an investigation by way 16 of ORS 757.215 (2) which states that, "This section does not prevent the commission and 17 the utility from entering into a written stipulation at any time extending any period of 18

- 19 suspension."<sup>63</sup>
- 20 **Q**

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

<sup>&</sup>lt;sup>60</sup> Staff/300, Gibbens/12.

<sup>&</sup>lt;sup>61</sup> AWEC/200, Mullins/4.

<sup>&</sup>lt;sup>62</sup> Calpine/200, Higgins/14.

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

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

9

#### Q. What was the original intent of the NLDA queue?

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

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

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

#### 20 <u>2. NLDA Cap Issues</u>

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

<sup>&</sup>lt;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."68
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

third-party supplier (ESS). 19

#### Q. Do you agree with Staff's recommendation that PGE is obligated to inform customers 20

of their right to seek a NLDA cap waiver? 21

<sup>&</sup>lt;sup>65</sup> Staff/300, Gibbens/11.

<sup>&</sup>lt;sup>66</sup> Id.

<sup>&</sup>lt;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."69 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

- adjustment of 20% of fixed generation will be sufficient to compensate for RA until a 20
- separate investigation for the RIC and RAD is complete. 21

 <sup>&</sup>lt;sup>69</sup> Calpine/200, Bass/3.
 <sup>70</sup> PGE/200, Sims – Tinker/20.

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

## Q. Do any Parties agree with any of PGE's proposals regarding how load is measured against the NLDA cap?

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

#### C. The RIC

#### 17 <u>1. RIC Pricing and Characteristics</u>

#### 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.

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

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

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

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

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

#### D. Other Issues

#### 15 <u>1. NLDA Draft Contract</u>

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

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

#### 19 Q. Does PGE agree with Staff's position?

<sup>&</sup>lt;sup>72</sup> AWEC/200, Mullins/15.

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

<sup>&</sup>lt;sup>74</sup> Staff/300, Gibbens/13.

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

#### **RPS** Cost Recovery 11 2.

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

A. PGE is required to make at least one standard offer under Oregon law.<sup>76</sup> The current option 14 is a daily market option for long term DA and PGE has at least one customer participating. 15 While a customer is on the daily market option, the pricing is a Mid-Columbia market index 16 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 charged to the standard offer service customer, the cost to comply with the RPS for that 19 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

<sup>&</sup>lt;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

#### **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 lasting decision from this record or adopt a provisional solution while Parties participate in a 8 broad and far-reaching DA policy docket. Irrespective of this decision, it is imperative that 9 10 the Commission protect the reliability of the electric system by including mechanisms that ensure large new loads contribute toward the necessary costs of securing capacity required 11 to meet the system's RA requirements. Any other outcome would unnecessarily threaten 12 system reliability and unfairly burden cost of service customers with all reliability costs and 13 14 risks.

### List of Exhibits

<u>PGE Exhibit</u>	<b>Description</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

UE 358 / PGE / 301 Sims - Tinker / Page 1

Pocatello

# 2024 Resource Adequacy Assessment

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Missoula

Longview Yakima Kennewick Astoria Lewistor Richland St Helens Vancouver Pendleton Resource Adequacy Advisory Committee Salem **Steering Committee Meeting** Corvallis **BenNW Power and Conservation Council** Eugene August 30, 2019 Idaho Falls REGON

rat

Snake



Pacific

Ocean

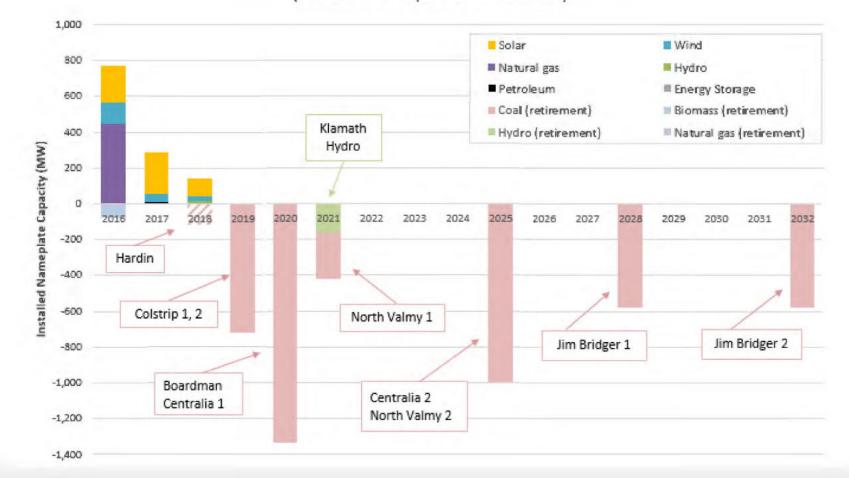
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## Outline

- 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
<b>Colstrip 1</b> (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

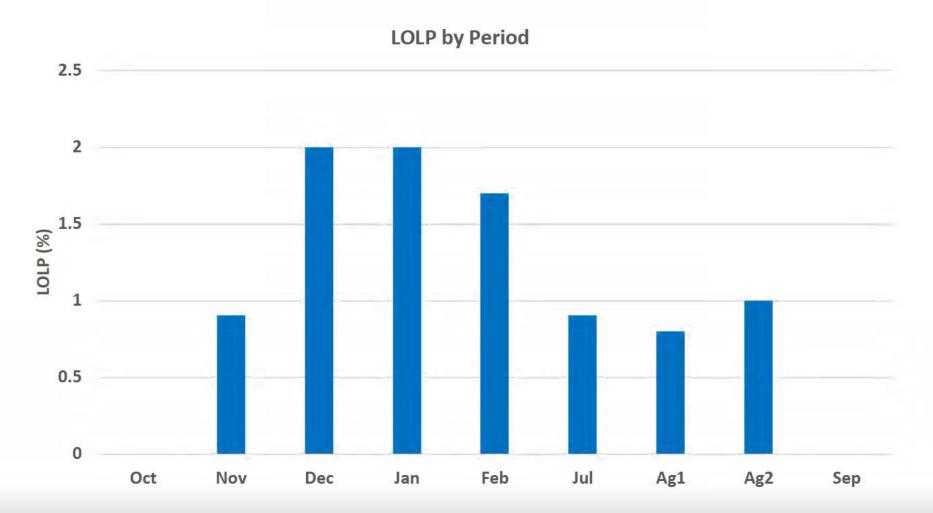


### 2021-24 Resource Adequacy Assessments

- 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)



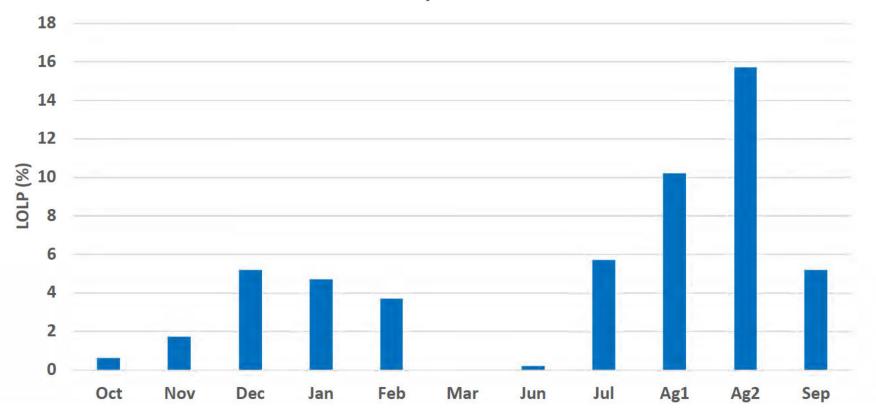
### Ref Case LOLP by Period





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

**LOLP by Period** 





### 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 (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 (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 (85 <sup>th</sup> Percentile)				
Medium Load	33.0	26.5 <sup>1</sup>		
Low Load (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 (

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

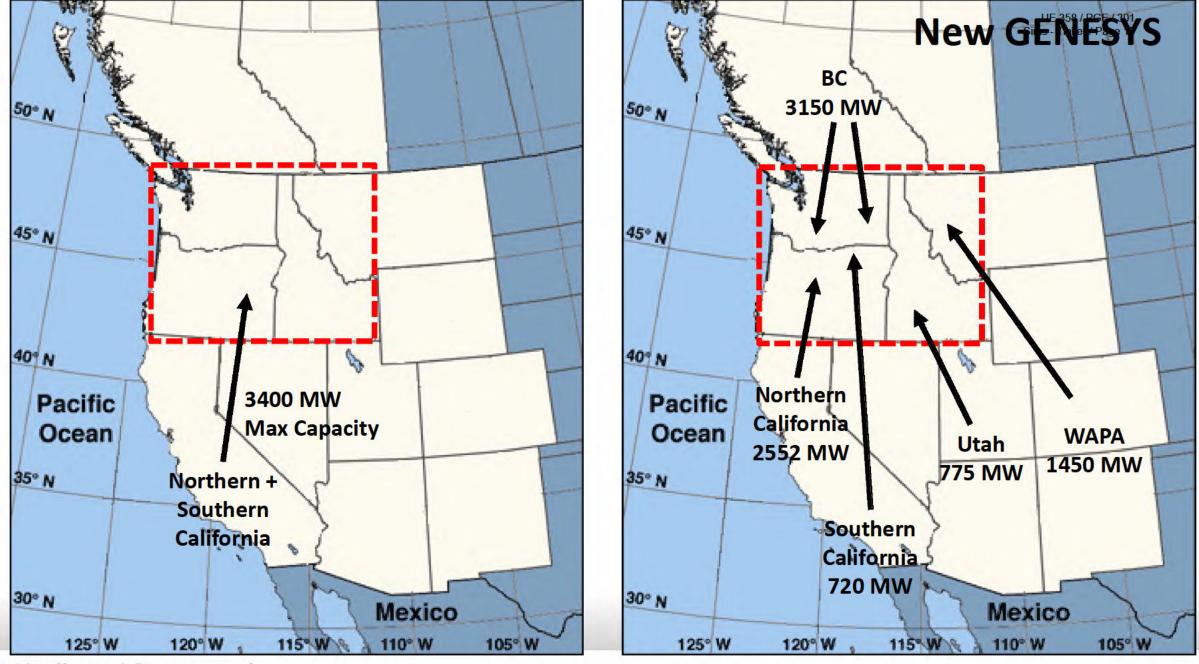
- Classic GENESYS
  - Max 2500 MW for Spot Market during hour of need winter only
  - Max 3000 MW for Purchase Ahead during off-peak hours ahead of future shortage
  - Max 3400 MW total import (spot + purchase ahead)
  - Only from California (as a surrogate for all imports)
  - Priced higher than any 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	То	Min Transfer Cap <sup>1</sup> (MW)
New GENESYS Assum	ptions (to potential	market sources only <sup>1</sup> )
Northern California	Pac West	2552
LADWP	BPAOR	720
BC	PS North	2762
BC	Avista	388
WAPA	NW	1450
Pac Utah	Pac Idaho	775
Total		8647
Current GENESYS Asso	umption	
California	PNW	3400





### Classic vs. New GENESYS

<u>Caveat</u>: 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.

- <u>Test</u>: Compare hourly simulated dispatch for the 2024 reference case using 1950 temperatures and 2001 hydro conditions (i.e. a "bad" year)
- Classic GENESY
  - 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>	Implied LOLP
High Load (85 <sup>th</sup> Percentile)					from New GENESYS is 0.5%
Medium Load	33.0	26.5	0.9	0.3	
Low Load (15 <sup>th</sup> Percentile)					

<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;

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		mary		F	Proposed Schedule	e 689 Charges		
Distribution* On Peak RIC RAD Total RAD% *First 4000 kW		\$1.53 \$2.61 \$0.58 \$9.08 \$13.80 66%	\$1.49 \$2.53 \$0.58 \$9.08 \$13.68 66%	\$10.00 \$9.00 \$8.00 \$7.00 \$6.00 \$5.00 \$4.00 \$3.00 \$2.00 \$1.00 \$0.00					
					Distribution*	On Peak	RIC	RAI	0

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
Customers - Three Phase Energy (MWh)		15	15	15	15	15	15	15	15	15	15	15	15	180	
	On-Peak	42451.997	41455.874	41140.361	42069.71	42469.611	43450.973	46134.115	47949.039	48625.893	45479.264	42834.757	42810.908	526872.502	
	Off-Peak	30711.67	30352.79	29507.487	28803.18	30616.787	31234.449	32396.3	34412.277	33424.625	32009.412	30702.02	31127.206	375298.203	
Facility Capacity (kW)															
	First 1,000 kW	14200	14200	14200	14200	14200	14200	14200	14200	14200	14200	14200	14200	170400	
	1,001-4,000 kW	47094	47094	47094	47094	47094	47094	47094	47094	47094	47094	47094	47094	565128	1651714
	Over 4,000 kW	74060	75293	76648	75670	75676	74856	77400	78353	77892	77946	76961	75431	916186	
Demand (kW)															
	On-peak	111692	112611	115183	119714	121187	125313	132495	136040	135934	133363	122624	114808	1480964	
	Off-peak increment														
Reactive Demand (kVar)		18234	16936	18358	17487	17701	18810	21249	25817	22033	20750	18422	17612	233409	
Calendar Energy (MWh)		71237.851	71895.937	70054.265	75157.763	71263.576	79745.56	80805.937	84756.447	79658.198	76437.246	71285.523	71043.382	903341.685	
RAD Charge	9.08	\$1.014.163	\$1 022 508	\$1 045 862	\$1 087 003	¢1 100 378	¢1 127 842	\$1 203 055	¢1 225 243	\$1,234,281	\$1 210 036	¢1 112 426	\$1 042 457	\$13,447,153	
Per Customer	5.06									\$82,285.38				\$896,476.87	
PGE LOLE Goal:	1 day/10 yrs	1													
LTDA LOLE Incremental Delta:	8 day/10 yrs	1 8													
Total Cost/10 year	\$8,964,768.75														
Reliability/ incremental day	\$1,280,681.25														

	AВ	C D	E	F	G	н	1	J	K	L	м	N	0	Р	Q	R	s	т	U	v	w x	Y	Z	AA	AB	AC AD	AE	AF	AG	AH	Al	AJ
П	Т																															
1																																
3																																
4	Sche	dule	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total							1										1
6	Sche	dule 485S 201-4,000 kW V2003																														
8	Cu	stomers - Single Phase stomers - Three Phase ergy (MWh)	0	0	0	0	0	0	2	0	0	0	0	0	0 24																	-
10	En	ergy (MWh) On-Peak	556	666	602	577	561	546	647	680	700	638	582	534	7,290																	
12	Fac	Off-Peak cility Capacity (kW)	354	391	364	353	341	339	382	406	451	376	341	342	4,440																	
14		First 200 kW Over 200 kW	400 1,668	400 1,668	400 1,668	400 1,668	400 1,668	400 1,668	400 1,668	400 1,668	400 1,668	400 1,668	400 1,668	400 1,668	4,800 20,016																	-
16	Der	mand (kW) On-Peak	1.759	1.925	1.828	1.812	1.918	1.886	1.955	2.072	2.034	1.956	1.732	1.684	22.561																	-
18	Rei	Off-Peak Increment active Demand (kVar)	34 431	0 514	0 462	0 465	0 472	0	0 503	0 535	0 554	0 549	0 455	0 476	34 5,917																	-
20	Cal	lendar Energy (MWh) dule 485S 201-4,000 kW V2010	853	963	964	921	974	869	1,109	1,103	1,040	1,066	979	882	11,722																	
22	Sche Cu:	dule 485S 201-4,000 kW V2010 stomers - Single Phase stomers - Three Phase	0	0	0	0	0	0	0	0	0	0	0	0	0																	
24	Cu: En	stomers - Three Phase ergy (MWh)	8	8	8	8	8	8	8	8	8	8	8	8	96																	
26		On-Peak Off-Peak	1,525	1,569 1,137	1,576	1,514 1,063		1,577 1,134	1,570	1,544 1,064	1,653 1,132	1,521	1,540	1,649	18,727 13,117																	
28 29	Fac	cility Capacity (kW) First 200 kW	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	19,200																	
30 31	Der	Over 200 kW mand (kW)	4,446	4,637	4,739	4,597			4,722		4,817		4,792	4,339	55,613															-		-
32	Ħ	On-Peak Off-Peak Increment	4,752 9	4,911	4,990 1	4,871 9	4,747 36	4,801 2	4,977 3	5,079 6	5,055 0	4,939 25	4,957 77	4,662 17	58,741 186																	-
34	Rea	active Demand (kVar) lendar Energy (MWh)	617 2,422	557 2,465	592 2,664	641 2,552		628 2,660	608 2,873	571 2,649	537 2,517	554 2,719	484 2,780	490 2,827	6,875 31,848																	-
36 37	Sche	due         d																											_			-
38 39	Cu	stomers - Single Phase stomers - Three Phase	0	0	0	0	0	0	0	0	0	0 8	0	0	0 96																	
40	En	ergy (MWh) On-Peak	2,071	2,085	1,980	1.939	1.897	1,907	2,096	2,084	2,138	1,906	1,853	1,806	23.763																	
42	Fac	Off-Peak cility Capacity (kW)	1,141	1,108	1,064	976	993	1,062	1,127	1,120	1,150	1,016	1,022	1,010	12,789																	-
44		First 200 kW Over 200 kW	1,600 6.030	1,600 6.194	1,600 6 239	1,600 6.404	1,600 6.572	1,600 7.052	1,600 7.153	1,600 7.290	1,600	1,600 6.760	1,600 5.767	1,600 5.416	19,200 78.371																	-
46	Der	mand (kW) On-Peak	5,958	6,052	6,117	6,254	6,385	6,753	6,835	6,949	7,109	6,531	5,753	5,477	76,173																	-
48 49	Rei	Off-Peak Increment active Demand (kVar)	3	36	7	0 332	0 485	10 584	7 581	0 688	0 636	0 477	0 185	0	63 4,280																	
50	Cal	lendar Energy (MWh)	3,009	2,909	3,039	2,887	3,118	2,914	3,473	3,253	2,972	3,070	3,051	2,833	36,530																	
52	Sche Cu:	dule 485S 201-4,000 kW V2012 stomers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0																	-
54	Cu	stomers - Three Phase ergy (MWh)	99	99	99	99		99	99	99	99	99	99	99	1,188																	
56 57	++	On-Peak Off-Peak	10,452 6,182	9,807 5,671	9,873 5,603	9,490 5,238	9,492 5,251	9,999 5,617	10,303 5,596	10,752 5,797	11,090 6,022	9,669 5,298	9,583 5,387	10,168 5,968	120,679 67,630																	
58 59	Fac	cility Capacity (kW) First 200 kW	19.800	19.800	19.800	19.800	19.800	19.800	19.800	19.800	19.800	19.800	19.800	19.800	237.600																	
60 61	Der	Over 200 kW mand (kW)	23,196	24,369	24,194	25,564		27,829	25,820	29,108	30,309			22,113	303,496																	-
62		On-Peak Off-Peak Increment	33,091 430	34,067 375	33,750 540	35,274 232	205	36,803 452	35,579 119	37,966 279	39,191 4	111	233	32,747 85	420,009 3,065																	-
64 65	Rea	active Demand (kVar) lendar Energy (MWh)	937 15,583	1,316 14,097	1,490 15,451	2,132 14,585	2,652	3,329 15,325	3,162 17,136	3,244 16,805	3,421 15,464		1,686	1,147 16,236	27,228 188,210																	
66 67	Sche	dule 485S 201-4,000 kW V2013																														-
68 69	Cu	stomers - Single Phase stomers - Three Phase	0	0	0	0 32	0 32	0 32	0	0 32	0	0 32	0 32	0	0 384																	
70	En	ergy (MWh) On-Peak	5,023	5,063	4,942	4,806	5,009	5,030	5,272	5,596	5,779	5,105	4,724	4,697	61,046																	-
72	Fac	Off-Peak cility Capacity (kW)	3.284	3.181	3.139	2.984		3.044	3.248		3.443	3.112	2.883	2.989	37.901																	
74	H	First 200 kW Over 200 kW	6,400 12,071	6,400 12,956		6,400 13,639		6,400 14,565	6,400 15,421	6,400 16,615	6,400 17,135		6,400 12,817	6,400 12,011	76,800 170,257																	
76 77	Der	mand (kW) On-Peak	14,341	14,969		15,704	16,796	16.389	17.053	18 027	18,444		15,043	14,339	193.036																	
78 79	Rei	Off-Peak Increment active Demand (kVar)	16 475	75 499	5 689	27 848	98 967	61 1.161	65	14 1.198	3	0 892	52 723	127 547	543 10.289																	<u> </u>
80 81	Cal	lendar Enerov (MWh)	7.782	7.508	8.067	7.715	8.816	7.924	9.184	9.168	8.334	8.635	8.074	7.734	98.941																	-
82 83	Sche Cu	dule 485S 201-4,000 kW V2014 stomers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0							_										
84 85	Cu	stomers - Three Phase ergy (MWh)	3	3	3	3	3	3	3	3	3	3	3	3	36																	+
86 87	Ħ	On-Peak Off-Peak	409 291	502 338	553 390	580 433	418 300	568 411	528 371	682 485	706 496	717 467	735 531	591 411	6.989 4,923							-										
88 89	Fac	cility Capacity (kW) First 200 kW	600	600	600	600	600	600	600	600	600	600	600	600	7.200																	
90 91	Der	Over 200 kW mand (kW)	2,430	2,317	1,619	1,581	1,459	1,604	1,935	2,318	2,274	2,847	2,414	2,137	24,935				-			-										-
92 93	ŦĨ	On-Peak Off-Peak Increment	2,488 15	2,411	1 878	1,823	1,728	1,857	2,132 20	17	2,394	2,866	2,497 20	2,255 10	26,771 92							-										+
94 95	Rea	active Demand (kVar) lendar Energy (MWh)	439 656	383 764	332 942	281 1,003	302 775	359 960	456 969	498 1,185	610 1,086	732 1,244	588 1,344	492 1,008	5.472 11,936							-										+
96 97	Sche	dule 485S 201-4,000 kW V2015																														+
98 99	Cu	stomers - Single Phase stomers - Three Phase	0	0	0	0	0	0	0	0	0	0	0	0	0				_			-										+
100	En	erav (MWh) On-Peak	238	247	274	228	220	242	274	261	280	281	274	256	3.073							-										+
102	Far	Off-Peak allity Capacity (kW)	130	142	158	122	123	133	163	142	154	170	155	144	1,736																	+
104	Ĩ	First 200 kW Over 200 kW	200 732	200 757	200 780	200 745	200 723	200 721	200 741	200 762	200 752	200 743	200	200 713	2,400 8,910																	+
106	Der	mand (kW) On-Peak	813	864	884	849	851	903	910	961	952	909	907	820	10,623																	1
108	Re	Off-Peak Increment	0	0	0 227	0 249	0	0 212	215	0	0	0 206	0 235	0 243	2,722							-										+
109	Re	acuve Demand (kVar)	242	237	227	249	207	212	215	222	227	206	235	243	2,722												_					

	AE AF	AG	An	A		
111         Lastores         Soudi 4455 201-4,000 kW V2016         Lastores         Lastores <thlastores< th="">         Lastores         <th< th=""><th></th><th></th><th></th><th></th><th></th></th<></thlastores<>						
11         Countress-Single Phale         O						
111         Customes - Three Phase         7 <th></th> <th></th> <th></th> <th></th> <th></th>						
111         On-Peak         654         628         629         617         616         659         678         726         726         651         623         633         7.945           171         OI-Peak         423         404         397         392         387         412         422         453         451         406         4.974						
1171 Untreak 423 444 397 332 387 412 422 453 455 455 413 407 408 4374 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1						
113 First 200 kW 1,400 1		-				
120 Over 200 kW 828 888 943 855 807 801 849 900 875 855 849 783 10.236						
121 Demical KW 626 066 943 056 00/ 001 649 900 075 053 049 763 10,236						
123         OP-Peak         1785         1775         1814         11812         1870         1224         2274         2207         1900         1445         1725         23.087           233         OI-Peak Increment         0         6         5         0         40         0         0         0         0         76	_					
123         Off-Peak Increment         0         6         5         5         0         40         20         0         0         0         76 <th< th=""></th<>						
123         Claendar Energy (MWh)         1,008         940         1,024         1,000         1,082         1,88         1,087         1,119         1,098         1,047         12,821         Image: Claendar Energy (MWh)           124         1         1         1,082         1,087         1,119         1,098         1,047         12,821         Image: Claendar Energy (MWh)         Image: Claendar Energy		_				
22 Schedule 455 201-4,000 kW V2017						
123         Customer - Sinde Phase         0 <th></th> <th></th> <th></th> <th></th> <th></th>						
133         [D-Peak         5,400         5,327         5,145         5,120         5,238         5,608         5,857         5,505         5,269         5,364         64,771						
131         On-Peak         5.460         5.27         5.145         5.120         5.285         5.605         5.895         5.864         6.471           132         OF-Peak         3.29         3.226         3.217         3.322         3.371         3.869 <th></th> <th></th> <th></th> <th></th> <th></th>						
T33         Finality Capacity W/I)         Finality Capacity W/I         Finality Capacity W/I <th final="" th="" transf<=""><th></th><th>_</th><th></th><th></th><th></th></th>	<th></th> <th>_</th> <th></th> <th></th> <th></th>		_			
33         Over 200 kW         12.574         12.916         13.522         13.425         13.033         13.577         14.246         14.974         15.417         13.919         12.474         12.232         162.281         Image: Control or Contro or Contro or Control or Contro or Control or Control or Contro						
132 Demand W/N 15.072 15.373 15.807 15.707 15.462 15.862 16.300 16.856 17.186 16.210 15.138 15.003 189.976		-				
133         Olf-Peak Increment         0.60         615         0.579         0.787         0.897         0.714         0.656         615         8.792           137         Reactive Demand (Vian)         2.28         333         2.925         324         486         442         623         555         642         630         419         3565         5.410   <						
L33         Preduzive Definition (IVrat)         ZoO         333         Zo1         344         4404         4402         Co1         355         062         S30         419         365         5,410         100 <th< th=""><th></th><th>_</th><th></th><th></th><th></th></th<>		_				
112 Customer SingPhase 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0						
142 Customen - Three Phase 27 27 27 27 27 27 27 27 27 27 27 27 27						
121         Oh-Peak         2.302         1.066         3.159         1.069         3.178         3.872         3.271         3.871         3.9044           123         OH-Peak         2.152         1.968         1.962         2.164         2.162         2.021         2.301         3.9044						
127         Olf-Peak         2.152         1.945         1.986         2.162         2.148         2.155         2.264         2.032         2.021         2.058         2.4643         Image: Control of the state of t	+ $+$					
133         Owner 200 WW         7.860         5.400						
150         Own 20 W         7.859         7.954         8.523         8.708         9.174         9.785         10.284         11.451         9.480         8.070         110.322           151         Demard With		-				
132 (JP-Pask moment 56 21 10.234 10.232 10.740 10.221 11.289 11.733 12.114 12.582 13.045 11.526 10.434 10.491 135.422						
133         Oth-Peak Increment         59         21         44         7         0         8         20         4         8         0         0         36         207						
State         Calendar Energy (MWh)         5.110         4.864         5.137         4.972         5.551         5.484         6.071         5.836         5.425         5.611         5.565         5.392         64.716         Image: Colored and the state         Image: Colored and and and the state         <		_				
159						
135         Customes - Sinde Phase         0 <th></th> <th></th> <th></th> <th></th> <th></th>						
131         Oh-Peak         97         89         86         173         334         174         159         124         665         266         8.683         1339   <		_				
133         First 1300 kW         1.000						
175         Ower 4200 W/         3.387         4.202         4.398         4.065         4.247         4.156         4.082         3.825         48.518         Image: Control of the contro of the control of the control of the control of the con						
16/J Uentratio (W7) 16/J U						
133         OIP-Peak Increment         0         0         0         0         0         0         0         0         0         70						
171 Calender General (MWs) 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0						
172   1   2   2   2   2   2   2   2   2						
Trace         Phase         1 <th1< th="">         1         <th1< <="" th=""><th></th><th></th><th></th><th></th><th></th></th1<></th1<>						
173         Ensergy (MWR)         1 <th1< th=""> <th1< th=""> <th1< th=""> <t< th=""><th></th><th>-</th><th></th><th></th><th></th></t<></th1<></th1<></th1<>		-				
177 0/P-Park 667 758 699 662 688 786 751 781 789 846 684 790 8.938						
TTP         Fraction Concept/why						
133         Ower 200 kW         3.516         3.516         3.516         3.516         3.516         3.516         3.516         3.516         4.2192           133         Demark W/H						
101 Deminia (NY) 102 [On-Peak 3.271 3.469 3.552 3.327 3.380 3.364 3.679 3.700 3.752 3.580 3.374 3.277 41.685						
133         OR+Peak Increment         0		_				
133         Calendar Energy (M/h)         1.700         1.987         1.649         2.244         2.072         2.085         1.332         2.145         1.628         1.758         22.900         Image: Colored and Colored an						
189						
133         Countomes - Three Phase         0 <th></th> <th></th> <th> </th> <th></th> <th></th>						
Cost         Elitique (WMM)         O						
10tPeak         0 </th <th>+ <math>-</math></th> <th></th> <th></th> <th></th> <th></th>	+ $-$					
773 [Pris206W] 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0						
134 (W) 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0		-				
193         Ob-Peak         0						
1973 (Dd+Pásk Increment) 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0						
133         Calendar Energy (MWh)         0		_				
2021         Customers         There Phase         6         6         6         6         6         6         6         72	+ $+$					
323         [Or-Peak         2.291         2.246         2.227         2.247         2.547         2.597         2.618         2.227         2.048         2.023         2.77.82           235         [OF-Peak         1.366         1.352         1.274         1.441         1.453         1.543         1.206         1.6045						
333         Olt-Peak         1.385         1.332         1.270         1.281         1.476         1.463         1.543         1.206         16.045 <th></th> <th>_</th> <th>   </th> <th></th> <th></th>		_				
273         First 200 kW         7.20         1.200						
2/38 (UV#2/20/ AW / /,346 /,/40 /,556 6,656 6,547 6,666 9,014 9,156 6,392 6,164 /,425 6,506 9/,066 (UV#2,016 4,125 6,164 ),142 6,150 9/,066 (UV#2,016 4,125 6,150 9/,066 ),144 6,150 9/,066 (UV#2,016 4,125 6,150 9/,066 ),144 6,150 9/,066 (UV#2,016 4,125 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 (UV#2,016 4,125 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 (UV#2,016 4,125 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 (UV#2,016 4,125 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 (UV#2,016 4,125 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 ),146 6,150 9/,066 0,150 9/,066 ),146 6,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 ),146 6,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 9/,066 0,150 0,						
101         Or-Peak         6.982         7.304         7.219         8.042         7.304         7.287         7.048         6.285         91.487           211         OF-Peak Increment         0 </th <th></th> <th></th> <th></th> <th></th> <th></th>						
C11         Un+*eak Incoment         U <thu< th=""> <thu< th="">         U</thu<></thu<>						
1213         Colemar Energy (MWh)         3.476         3.669         3.391         3.297         4.388         4.244         4.200         4.037         3.502         2.349         2.859         43.881						
Clip         Construence         Transport         T						
211 [Cheller (WMM)						
213         Oth-Peak         4.497         4.206         4.240         4.130         4.357         4.584         4.833         5.041         4.804         4.475         4.120         4.239         53.525           2023         Fisiolity Geodery WW)         6         4.200         4.357         4.584         4.833         5.041         4.804         4.475         4.120         4.239         53.525         0         <	+ $+$					
200 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	1		1			

ABC	D	E		G		1	J	K		М	N	0	Р	Q	R	S	T	U	v w	X Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	Al	AJ
222 Over 223 Demand	r 200 kW d (kW)	23,057	23,594	23,764	26,524	27,461	28,924	30,325	31,581	28,949	25,422	21,337	20,305	311,243																	
222 On-P 225 Off-Pe	Peak Peak Increment	23,873 31 3,749	15	24,472 9 3,993	26,736 0 4,362	0	28,586 110 4,362	679	30.863 4 4.572	0	25,835 0 3,658	22,497 0 3,001	21,373 281 2.625	313,942 1,129 47,398																	
226 Reactive 227 Calendar	ar Energy (MWh)	3,749		3,993				4,435	4,572		3,658	10,178	2,625	47,398																	
229 Schedule	485P 201-4,000 kW V2014	0								0				24																	
231 Energy (	(MWh) Peok	384	424	436	431	485	451	513	505	499	496	462	440	5.526																	
233 Off-Pe	Peak Capacity (kW)	251	277	310	317	356	329	399	373	346	342	312	279	3,890																	
235 First 2 236 Over	200 kW	400	400	400 1,232	400	400 1,343	400	400	400	400 1,423	400 1,376	400	400	4.800 15,384																	
237 Demand 238 On-P	d (kW) Peak	1,169	1,329	1,333	1,393	1,424	1,308	1,404	1,463	1,490	1,451	1,390	1,336	16,490																	
239 Off-Pe 240 Reactive	Peak Increment e Demand (kVar)	0 223	0 225	0 252	218	0 276 777	0 230	0	0	0 260	0 226	0 220	0 216	0 2,783																	
241 Calendar 242	ar Energy (MWh)	604	720	724	828	777	882	961	907	820	847	709	636	9,416																	
243 Schedule 4 244 Custome	485P 201-4,000 kW V2015 hers - Three Phase	2	2	2	2	2	2	2	2	2	2	2	2	24																	
245 Energy ( 246 On-P	(MWh) Peak	1,534	1,734		1,520	1,562	1,561		1,870	1,959	1,888	1,785	1,627	20,603																	
247 Off-Pe 248 Facility C	Peak Capacity (kW)	1,026	1,046		961	933	946	1,149	1,150	1,173	1,163	1,068	1,042	12,671																	
249 First 2 250 Over :	200 kW r 200 kW	400 5,660	400 5,778	400 5 893	400 5,652	400 5,633	400 5,505	400 5,799	400 5,946	400 5,848	400 5,868	400 5,714	400 5,507	4.800 68,803																	
251 Demand 252 On-pe	d (kW) peak	5,460	5,601	5,688	5,498	5,791	5,670	6,091	6,409	6,145	6,036	5,871	5,501	69,761																	
253 Off-pe 254 Reactive	e Demand (kVar)	0 674 2,434	0 642 2,851	0 720 2,578	0 590 2,748	0 655 2,305	0 685 2,835	0 789 3,238	0 774 3,125	13 836 3,038	0 777 3,085	0 744 2,613	10 699 2,364	23 8,585 22,212																	
255 Calendar	485P 201-4 000 KW V2016	2,434	2,851	2,5/8	2,748	2,305	2,835	3,238	3,125	3,038	3,085	2,613	2,364	33,213										_							
258 Custome	ners - Three Phase	0	0	0	0	0	0	0	0	0	0	0	0	0																	
260 On-P	Peak	0	0	0	0	0	0	0	0	0	0	0	0	0																	
262 Facility C	Capacity (kW) 200 kW	0	0	0	0	0	0	0	0	0	0	0	0	0																	
264 Over 265 Demand	r 200 kW d (kW)	0	0	Ő	Ő	0	Ő	Ő	Ő	ŏ	Ő	Ő	Ő	0																	
266 On-pe 267 Off-pe	peak beak increment	0	0	0	0	0	0	0	0	0	0	0	0	0																	
268 Reactive 269 Calendar	e Demand (kVar) ar Energy (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0																	
270 271 Schedule	485P 201-4,000 kW V2017																														
272 Custome 273 Energy (	ners - Three Phase (MWh)	8	8	8	8	8	8	8	8	8	8	8	8	96																	
274 On-P 275 Off-Pe	Peak Peak	1,872	1,982	2,049 1 397	2,101 1,468	2,238 1,522	2,289	2,747 1,890	3,003 2,067	2,956 1,997	2,885 2,017	2,671 1,903	2,758 1,914	29,552 20,318																	
276 Facility C 277 First 2	Capacity (kW) 200 kW	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	19,200																	
278 Over: 279 Demand	r 200 kW d (kW)	6,234	5,995	6,013	7,742	6,644	7,579		9,990 9,468	9,665	9,149 8,743	7,913	7,788	93,944																	
280 On-pe 281 Off-pe	peak peak increment	6,401 0 995	6,198 7 1,093	10	7,633	0	7,499		9,468 0 1,278		8,743 40 1,203	7,772	7,671	92,377 66 13,199																	
282 Reactive 283 Calendar	e Demand (kVar) ar Energy (MWh)	2,999	3,399	3,346	3,954	3,474	4,315		5,245	1,324 4,806	4,958	4,189	4,138	49,711																	
285 Schedule 4	485P 201-4,000 kW V2018	1	- 1	1	- 1	- 1	- 1	1	1	1	1		1	12																	
287 Energy (	(MWh) Peak	560	514	515	514	557	565	613	672	636	554	529	555	6,783																	
289 Off-Pe	Peak Capacity (kW)	381	334	339	329	372	357	380	442	385	352	529 335	555 375	4.380																	
291 First 2 292 Over	200 kW r 200 kW	200	200 1.826	200	200	200	200 1.826	200	200 1.826	200 1.826	200 1.826	200	200	2,400 21,912																	
293 Demand 294 On-pe	d (kW) peak	1,468	1,479	1,487	1,706	1,742	1,936	1,972	2,057	1,995	1,775	1,556	1,416	20,589																	
295 Off-pe 296 Reactive	e Demand (kVar)	0	0	0	0	0	0	0	0	0	0	0	0	0																	
297 Calendar 298	ar Energy (MWh)	895	869	829	934	858	1,044	1,046	1,152	991	916	791	823	11,148																	
299 Schedule 300 Custome	489P GT 4,000 kW V2004 hers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12																	
301 Energy ( 302 On-P	(MWh) Peak	3,588	3,533	3,519	3,699	3,872	3,846	3,969	3,966	4,122	3,815	3,621	3,756	45,306																	
303 Off-Pe 304 Facility C	Peak Capacity (kW)	2.352	2.315		2.380	2.492	2.361		2.494	2.571	2.534	2.339	2.395	29.371																	
305 First 1 306 1,001	d kW/ d kW/ back Increment beak Increment beak Increment beak Increment be Energy (M/N) are Energy (M/N) are Energy (M/N) are Energy (M/N) beak Increment beak Increment beam Inthe Phase (INTH) The Phase Increment beam Inthe Phase Inthe Phase Inthe Phase Inthe Phase Inthe Phase Inthe Phase Inthe Phase Inthe Phase Inthe Phase Inthe Phase In	3,000	3,000	3,000	3,000	3,000	3,000	3.000	3,000	3 000	3,000 7,633	3,000 7,633	3,000	36,000	139,596	11633															
308 Demand 308 Oc.~	d (kW)	11.148			10,595	11.746	11.313		11.828		10.608	10,266	10.591	130.851	10.904	0.937355															
310 Off-pe	e Demand (kVar)	3,503	2,980	9,646	0	0	3.216	0	3 251	0	0	0	0	38.851	10,004	5.557 505															
312 Calendar 313	ar Enerov (MWh)	5.848					6.664		6.693		5.961	6.151	5.940	74.678																	
314 Schedule	489P GT 4,000 kW V2010	1	1	1	1	- 1	1	1	1	1	1	1	1	12																	
316 Energy (	(MWh) Peak	3.246	3,395	3.274	3.299	3.127	3,558	3.518	3,505	3.532	3,635	3.369	3.485	40.944																	
318 Off-Pe 319 Facility C	Peak Capacity (kW)	2,213	2,449	2,245	2,159	2,157	2,492	2,365	2,365	2,378	2,525	2,288	2,528	28,163																	
320 First 1 321 1,001	1,000 kW 11-4 000 kW	1,000 3,000	3,000	3 000	3,000	3,000	1,000	3,000	1,000 3,000	3,000	1,000 3,000	1,000 3,000	1,000 3,000	12,000 36,000																	
322 Over 323 Demand	r 4.000 kW d (kW)	7.559	7.559	7 559	7.559	7.559	7.559	7.559	7.559	7.559	7.559	7.559	7.559	90.708																	
324 On-pe 325 Off-pe	peak peak increment	9,841 0	0	10,376 0	0	0	10,952 0	0	11,223 0 4,131	11,304 0	11,366 0	11,753 0	10,461 0	130,603 0																	
326 Reactive	e Demand (kVar)	4,030 5,189	3,837 5,993	4,125 5,359		3,888 4,882	3,968 6,843	4,148 6,201	4,131 6,072	3,927 5,734	4,073 6,229	3,657 5,181	4,002 5,325	47,420 69,054																	
328 329 Schedule	ar Energy (MWN) 489P GT 4,000 kW V2011 ters - Three Phase (MWh) Peak Peak																														
330 Custome 331 Energy (	ners - Three Phase (MWh)	2	2	2	2	2	2	-	2	2	2	2	2	24																	
332 On-P 333 Off-Pe	Peak Peak	8,355 6,319	8,262 6,162	7,889 5,791	7,960 5,796	8,118 6,221	8,488 6,166	8,532 6,216	8,822 6,739	9,356 6,723	8,838 6,374	8,236 6,113	7,994 6,065	100,849 74,684																	

A B C D	E	F	G	н		J	к	L	м	Ν	0	Р	0	R	s	TU	v	w x	Υ	z	AA	AB	AC AD	AE	AF	AG	AH	Al	AJ
334 Facility Capacity (kW)	-							-			0		4							~		10	AC AD	AL.	<u> </u>	7.0	20	<u>A</u>	~~
335 First 1,000 kW 336 1,001-4,000 kW	1,200	1,200 8,094	1,200 8.094	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	14,400 97,128																
337 Over 4,000 kW 338 Demand (kW)	13,827	13,827	13 827	13,827	13,827	13,827	14,070	13,917	14,006	14,006	14,006	14,006	166,973																
332 Demand (kW) 339 On-peak 340 Off-peak increment	20,116	19,349	20,694	20,499	21,186	22,169	23,113	22,390	23,220	22,733	21,819	21,401	258,689																
340 Off-peak increment 341 Reactive Demand (kVar)	2.577	0	0	0	0 2.741	0 2.928	0 2.993	0 7.320	0 2.929	0 3.010	0	0 2.892	0 38.059																
341 Reactive Demand (Kvar) 342 Calendar Enerov (MWh) 343	14.287		13.567	14.668	14.336	15.030	15.461	16.193	15.351	14.390	14.222	14.183	175.568																
33         Ohr-beak           33         Ohr-beak           341         Off-beak           342         Off-beak           343         Off-beak           344         Reactive Demand rkVari           345         Calendar Energy rMWhi           343         Schedule 489P GT 4,000 kW V2012           343         Calendars Energy rMWhi	-																												
345 Customers - Three Phase	3	3	3	3	3	3	3	3	3	3	3	3	36					Jan Feb	Mar	Apr	May	Jun	Jul Aug	Sep	Oct	Nov	Dec	Total	
346         Enerov (MWh)           347         On-Peak           348         Off-Peak	4 064	4.047	4 106	4 188	4.452	4 591	4 933	5 262	5 102	4.405	4 195	4.118	53.464			Customers - Thre	e Phase	15 15	15	15	15	15	15 15	15	15	15	15	180	
348 Off-Peak	4.064 2,674	2,524	2 529	2,642	2,755	4.591 2,836	3,097	3,308	3,094	2,724	2,623	2,617	33,423			Energy (MWh)		42,452 41,456					46,134 47 949				42,811	526,873	
349         Focility Capacity (kW)           350         First 1.000 kW           351         1.001-4.000 kW           352         Over 4.000 kW           352         Demand (kW)           352         Demand (kW)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000		-	On-Pr Off-Pr	eak eak	42,452 41,456 30,712 30,353	41,140 29,507	42,070 28,803	42,470 30,617	43,451 31,234	46,134 47 949 32,396 34,412	48,626	45,479 32,009	42,835	42,811 31,127	375,298	
351 1,001-4,000 kW	9,000 4,000	9,000	9,000 4,616	9,000 3,979	9,000 3,928	9,000 3,591	9,000 4,367	9,000 4,756	9,000	9,000 4,550	9,000	9,000	108,000 50,336			Facility Capacity ( First 1		14,200 14,200	44.000	44.000	14.200	44.000	14,200 14,200	44.000	14.200	14 200	14.200	170.400	
352 Demand (kW)																1,001		47,094 47,094	47,094	47,094	47,094	47.094	47.094 47.094	47.094	47.094	47,094	47.094	565,128	1,651,714
252 Off-peak	11,087	11,806	12,691	14,017	14,514	15,419	0	0	16,152	15,256	12,966	11,595	167,689					74,060 75,293	76,648	75,670	75,676	74,856	77,400 78 353	77,892	77,946	76,961	75,431	916,186	
355         Off-peak increment           356         Reactive Demand (kVar)           357         Calendar Energy (MWh)	222	175	128	201	200	278	215	286	292	175	138	80	2,390			On-pe	ak	111,692 112,611	115,183	119,714	121,187	125,313	132,495 136,040	135,934	133,363	122,624	114,808	1,480,964	
357 Calendar Energy (MWh) 358	6,405	6,738	6,442	7,566	6,658	8,400	8,465	8,864	7,952	7,210	6,244	5,965	86,911			Off-pe Reactive Demand		18,234 16,936	18.358	17 487	17,701	18 810	21,249 25,817	22.033	20,750	18.422	17.612	233,409	
358 359 Schedule 489P GT 4,000 kW V2013																Calendar Energy	(MWh)	71,238 71,896	70,054	75,158	71,264	79,746	80,806 84,756	79,658	76,437		71,043	903,342	
360 Customers - Three Phase 361 Energy (MWh)	1	1	1	1	1	1	1	1	1	1	1	1	12																
362 On-Peak	2,270	2,205	2,261	2,275		2,228	2,303	2,298	2,232	2,291	2,282	2,257	27,184																
363         Off-Peak           364         Facility Capacity (kW)           365         First 1,000 kW	1,672		1,682					1,651			1,661	1,686		+ +															
365 First 1,000 kW	1,000 3,000	1,000 3,000	1,000 3,000	1,000 3,000		1,000 3,000	1,000 3,000				1,000	1,000 3,000	12,000					1014163 1022508	1045950	1097003	1100270	1127042 04	1203055 1235243	1024084	1210020	1112420	1042456 04	\$12 447 450	
366 1,001-4,000 kW 367 Over 4,000 kW 368 Demand (kW)	3,000	3,000 2,833	3,000 2,833	2,833	3,000 2,833	3,000 2,833	2,833	3,000 2,833	3,000 2,833	3,000 2,833	2,833	3,000 2,833	36,000 33,996					1014163 1022508 4405916 4324318	4254413	4267965	4401263	4497556.113	4729102 4959798	4941082	4666368	4428385	4452553.225	\$13,447,153 54328719.86	
368 Demand (kW) 369 On-peak	6.136		6.895	6.355		5.973	6.172	6.420			6.771	5.583	74.843															0.247514632	
365 On-beak 370 Off-peak increment	0	0	72	0	0	73	0	0	0	0	28	5.583	219															0.24/014032	
371 Reactive Demand (kVar) 372 Calendar Energy (MWb)	359	484	386 3.949	461 3.948		812 3.949	938 3.950	978 3.946	868 3.949	891 3.942	290 3.943	0 3,942	7,049	$+ - \overline{+}$							-								
373 374 Schedule 489P GT 4,000 kW V2014	0,040			0.040	5,000			0,040	2,040	-10-12	2,040	5,542										\$1,792,953.75							
3/4 Schedule 489P GT 4,000 kW V2014 375 Customers - Three Phase	1	1	1	1	1	1	1	- 1	1	1	1	1	12	H I					1						1				<u> </u>
372         Customers - Three Phase           374         Energy (MWh)           377         On-Peak           378         Off-Peak		2,978	0.0(2	0.050						3,236		2,831	36.440														\$896,476.87 \$8,964,768,75		
377 On-Peak 378 Off-Peak	3,005	2,978	2,812	2,852	2,899 2,106	2,315	2,393	3,233 2,300	3,282 2,508	3,236	2,994	2,831	36,440 26,962														\$8,964,768.75		
	1.000		1 000			1,000						1.000	12,000																
323         First 1,000 kW           381         1,001-4,000 kW           382         Over 4,000 kW		3,000			3,000	3,000	1,000 3,000	3,000	3,000			3,000					_												
382         Over 4.000 kW           383         Demand (kW)           384         On-peak           385         Off-peak increment	5.079	5.079	5.079	5.079	5.079	5.079	5.079	5.079	5.079	5.079	5.079	5.079	60.948																
384 On-peak	7,402	6,948	7,551	7,734	8,325	8,606	8,527	8,682	8,566	8,731	8,150	7,819	97,041																
385 Off-peak increment 386 Reactive Demand (k)(at)	0	0	0	0	0	626	0	0	0 624	0	0	0	2 748																
386 Reactive Demand (kVar) 387 Calendar Energy (MWh)	5,167		4,952	5,006	5,348	5,679	5,533			5,182	4,996	5,307	63,402																
385 385 Schedule 489P GT 4,000 kW V2016	-																												
	1	1	1	1	1	1	1	1	1	1	1	1	12																
391         Energy (MWh)           392         Energy (MWh)           393         Energy (MWh)           394         Facility Capacity (kW)           395         First 1,000 kW	3.006	2.956	3.158	3.648	3.293	3.272	3.408	3.382	3.729	3,627	3.570	3.757	40.807																
393 Off-Peak	2,152	2,324	2,244	1,875	2,352	2,495	2,481	2,628	2,403	2,626	2,805	2,740	29,127																
394 Facility Capacity (kW) 395 First 1,000 kW 396 1.001-4 000 kW	1,000	1,000	1 000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000																
396 1.001-4 000 kW 397 Over 4,000 kW	3.000 3,467	3.000	3 000 4,187	3.000		3.000	3.000 5,622	3.000		3.000	3.000	3.000	36.000																
398 Demand (kW) 399 On-peak																													
399 On-peak 400 Off-peak increment	7,428	8,006	8,368	9,668 0		8,788	9,575	9,329		9,347	9,055	9,655	108,088																
400 Off-peak increment     401 Reactive Demand (kVar)     402 Calendar Energy (MWh)     403	0	0	0	0	0	0	0	0	0		0	0	0																
402 Calendar Energy (MWh) 403	5,280	5,402	5 524	5,645	5,767	5,889	6,010	6,132	6,254	6,375	6,497	6,649	71,424				_												
405 Customers - Three Phase 406 Energy (MWh)	2	2	2	2	2	2	2	2	2	2	2	2	24	<u> </u>															
400         Chergy (WWH)           407         On-Peak           408         Off-Peak           409         Facility Capacity (kW)	6,799		6,575 5.018	6,693	6,600	6,377 5.094	6,883	6,656 5,207	6,881 5.068	6,691 5,102	6,477	6,528	79,775																
408 Off-Peak 409 Facility Capacity (kW)	.1000	0,010										.10.0.1																	
410 First 1.000 kW	2.000	2.000 6,000	2.000	2.000	2.000 6,000	2.000	2.000	2.000 6,000	2.000	2.000	2.000 6,000	2.000 6,000	24.000																
412 Over 4,000 kW 413 Demand (kW)	11,842	11,842	11 842	11,842	11,842	11,842	11,842	11,842	11,842	11,842	11,842	11,842	142,104																
413 Demand (kW) 414 On-peak	18,563	18,944	18,651	18,891	18,415	17,545	18,619	18,854	18,438	19,796	17,530	16,477	220,723																
415 Off-peak increment	0	0	0	0	37	0	0	0	0	153	0	0	190																
416 Reactive Demand (kVar) 417 Calendar Energy (MWh)	5,220	4,286	4,804	4,672	4,3/3	3,921 11,752	4,757	4,291	4,228	4,774	4,420	3,872	53,618 140,203	+ +															
417         Calendar Energy (MWh)           418         419           419         Schedule 489P GT 4,000 kW V2018																													
419 Schedule 489P GT 4,000 kW V2018 420 Customers - Three Phase 421 Energy (MWh)	2	2	2	2	2	2	2	2	2	2	2	2	24																
421 Energy (MWh) 422 On-Peak	7,876	7,290	7 307	7 307	7.685	7,708	8 129	8 492	8 415	7 727	7 300	7 819	93 241																
422 On-Peak 423 Off-Peak 423 Off-Peak 424 Facility Capacity (kW) 425 Facility Capacity (kW)	5.932	5.348	5.388	5.266	5.846	5.561	5.779	6.492	5.994	5.587	5.355	7,819 5.937	93,241 68.405																
424 Facility Capacity (kW) 425 First 1 000 kW	2 000	2,000	2 000	2 000	2 000	2,000	2 000	2 000	2 000	2 000	2 000	2,000	24,000																
426 1.001-4.000 kW	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000																
426 1,001-4,000 kW 427 Over 4,000 kW 428 Demand (kW)		14,260				13,275						13,283	169,190																
429 On-peak	18,426				20,262	21,160	21,674	22,716	22,520	21,693		18,690																	
430 Off-peak increment 431 Reactive Demand (kVar)	2.323	0 2.559	0 2.662	2.545	2.553	37 2.617	156 2.681	0 2.888	0 3.127	2.640	0 2.736	19 2.562	212 31.893	+	T				<u>⊢                                     </u>						7				<u> </u>
431 Reactive Demand (KVar) 432 Calendar Energy (MWh) 433	13.125	12.960	12.412	13.928	12.501	15.009	14.660	15.416	13.981	13.464	11.678	12.182	161.317																
434 Schedule 489T V2007	1													+ +															<u> </u>
435 Customers - Three Phase	0	0	0	0	0	0	0	0	0	0	0	0	0																
430 Energy (MWVN) 437 On-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0	+ +															
438 Off-Peak	0	0	0	Ó	0	0	0	0	0	0	Ó	0	0																
439 Facility Capacity (kW) 440 First 1,000 kW	0	0	0	0	0	0	0	0	0	0	0	0	0	<u> </u>															<u> </u>
435         Energy (MWh)           437         [Oh-Peak]           438         [Paclify Capacity (WV)]           434         [Pisit 1,000 kW]           434         [1,01-4 000 kW]           434         [Demand [kW]]           435         Demand [kW]	0	0	0	0	0	0	0	0	0	0	0	0	0																
443 Demand (kW)	0	0	U	0	0	U	U	U	U	U	U	U	0																
442 On-Peak 445 Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0																
Oirr eax increment	. 0		U	U	ן ט	U	U	U	U	U	U	J	0	L					L				1						

	ABC D	F	F	G	н		1	К		М	N	0	P	0	R	S	Т	U	v	w	X	Y	7	AA	AB	AC	AD	AE	AF	AG	AH	Al	AJ
446	Reactive Demand (kVar)	- 0		- 0		. 0	. 0		- 0			- 0	. 0	- 0		÷							-										<u> </u>
447	Calendar Energy (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0																			
448		-		-			-							-																			
	Schedule 489T V2012														-																		
450	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12		-																	<u> </u>
451	Energy (MWh)													12																			<u> </u>
452	On-Peak	3.944	3.741	3 880	3,960	4.057	4.247	4,188	4,403	4,459	4,440	4.386	4,772	50.476																			
453	Off-Peak	3.000			2.885	2.951		3.071	3,159	3,460	3,185	3.217	3,660	37,486																			
454	Facility Capacity (kW)																																
455	First 1.000 kW	1.000	1.000	1.000	1,000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1,000	12.000																			
456	1.001-4.000 kW	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000	36,000																			
457	Over 4.000 kW	8.997	8.997	8.997	8.997	8.997	8.997	8.997	8.997	8.997	8.997	8.997	8,997	107.964																			
458	Demand (kW)																																
459	On-Peak	12.804	8.745	10 570	10.724	11.079	11.616	10.305	11.676	11.723	11.530	11.570	13.191	135.533																			
460	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0																			
461	Reactive Demand (kVar)	437	1,635	1,851	2,293	2,290	2,039	2,116	2,452	2,450	2,321	2,094	2,213	24,191																			
462	Calendar Energy (MWh)	6,502	6,745	6,845	7,007	7,520	7,258	7,561	7,919	7,625	7,603	8,432	6,944	87,962																			
463																																	
464	Schedule 489T V2013																																
465	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12																			
466	Energy (MWh)																																
467	On-Peak	4,326	3,872	4,138	4,465	3,970	3,932	4,134	4,213	4,058	4,156	3,726	4,098	49,087																			
468	Off-Peak	2,887	2,670	2 833	2,806	2,563	2,706	2,431	2,803	2,530	2,518	2,537	2,600	31,883																			
469	Facility Capacity (kW)																																
470	First 1,000 kW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000																			
471	1,001-4,000 kW	3,000		3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000																			
472	Over 4.000 kW	14.264	14.860	14.860	14.860	14.860	14.860	14.860	14.860	14.860	14.860	15.139	15.139	178.282																			
473	Demand (kW)																																
474	On-Peak	17,031	19,301	14 858	16,578	15,549	16,021	15,280	17,356	18,422	18,157	18,977	15,994	203,524																			
475	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0																			
476	Reactive Demand (kVar)	12,923			13,086	12,483		13,154	15,091	13,990	13,856	17,711	15,594	167,134																			
477	Calendar Energy (MWh)	6,542	6,970	7,271	6,533	6,637	6,566	7,016	6,588	6,674	6,263	6,698	7,213	80,970																			
478																																	
479	Total Direct Access																																
480	Customers	293		293	293	293	293	293	293	293	293	293	293	3,516																			
481	Energy (MWh)	160,156	156,099	155,213	153,931		161,756	169,239	176,862	177,614	165,631	158,048	161,510	1,952,690																			
482	Facility Capacity (kW)	342,349	347,976		356,431	356,165	362,496	369,038	379,461	379,218		346,042	340,346	4,291,943																			
483	Demand (kW)	281,690	284,134		297,347	300,466	309,881	319,086	333,922			294,502	281,311	3,639,563																			
484	Reactive Demand (kVar)	42,546	45,360	43,693	46,482	47,539		53,152	60,530	55,324	51,990	49,958	45,408	591,974																			1
485	Calendar Energy (MWh)	152,857	153,328	154,228	159,839	157,029	169,065	177,565	180,993	169,161	166,819	157,739	155,007	1,953,631																			1
486																																	1
487										-																							

### 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.

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

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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

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Page 4 - COST OF SERVICE OPT OUT AGREEMENT SCHEDULE(S) - 5 year

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.
- 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.

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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 <u>all</u> 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.

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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 \_\_\_\_\_

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