Calpine Solutions Exhibit 100
Witness: Kevin C. Higgins

BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF OREGON

UE 335

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY,	)
	)
Request for a General Rate Revision.	)
	)

Opening Testimony of Kevin C. Higgins

on behalf of

Calpine Energy Solutions, LLC

June 6, 2018

OPENING TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this phase of the proceeding?

A. My testimony is being sponsored by Calpine Energy Solutions, LLC ("Calpine Solutions"). Calpine Solutions is a retail energy supplier that serves commercial and industrial end-use customers in 18 states, the District of Columbia, and Baja California, Mexico. Calpine Solutions serves more than 15,000 retail customer sites nationwide, with an aggregate load in excess of 4,500 MW. Calpine Solutions' retail customers are located in the service territories of more than 55 utilities. In Oregon, Calpine Solutions is currently serving customers in the service territories of Portland General Electric ("PGE") and PacifiCorp.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you ever testified before this Commission?

A. Yes. I have testified in twenty-six prior proceedings in Oregon, including five previous PGE general rate cases, UE 283 (2014), UE 262 (2013), UE 215 (2010), UE 197 (2008), and UE 180 (2006). In addition, I testified in the PGE Opt-Out case, UE 236 (2012) and the PGE restructuring proceeding, UE 115 (2001).

Further, I have testified in nine PacifiCorp Transition Adjustment Mechanism ("TAM") proceedings, UE 323 (2018 TAM), UE 307 (2017 TAM), UE 296 (2016 TAM), UE 264 (2014 TAM), UE 245 (2013 TAM), UE 227 (2012 TAM), UE 216 (2011 TAM), UE 207 (2010 TAM), and UE 199 (2009 TAM). I have also participated in six PacifiCorp general rate cases, UE 263 (2013), UE

246 (2012), UE 210 (2009), UE 179 (2006), UE 170 (2005), and UE 147 (2003), as well as the PacifiCorp Five-Year Opt-Out case, UE 267 (2013).

I also testified in the Investigation into PacifiCorp's Non-Standard Avoided Cost Pricing, UM 1802 (2017), the 2017 Inter-Jurisdictional Allocation proceeding, UM 1050 (2016) and Phase II of the Investigation into Qualifying Facility Contracting and Pricing, UM 1610 (2015).

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 200 proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also prepared affidavits that have been filed with the Federal Energy Regulatory Commission ("FERC").

Overview and Conclusions

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses the portion of PGE's testimony concerning direct access service. Specifically, I will focus on the future of the Five-Year Opt-Out program, issues pertaining to the application of the Renewable Portfolio Standard ("RPS") to direct access customers, and PGE's proposals regarding Electric Service Supplier ("ESS") scheduling practices.

Q. Please summarize your conclusions and recommendations.

A. I offer the following conclusions and recommendations:

1. Five-year Opt-Out Program. PGE is proposing to abandon the Five-Year Opt-Out program and convert it to a ten-year opt-out program by requiring participating customers to pay ten years' worth of transition adjustments, including ten years of PGE fixed generation costs. This proposal should be rejected by the Commission. PGE offers no credible evidence that remaining customers are negatively impacted from undue cost shifting when opt-out customers pay transition adjustments for five years instead of ten.

The transition adjustment for the opt-out program should be limited to five years because five years gives PGE sufficient time to plan for the exit of the opt-out customer. With five years' notice, there is no reason for PGE to plan to add any new resources to serve the departing load. Indeed, the departure of opt-out load allows PGE to *avoid* adding incremental generation resources that would otherwise be needed to serve the Company's system load. This avoided fixed generation cost is a *benefit* to the system that I estimate to be worth between $38.42/MWh and $41.77/ MWh. If the transition adjustment calculation is extended to ten years as proposed by PGE, then these avoided fixed generation costs should be credited against the fixed generation charge that PGE proposes to levy on opt-out customers in years six through ten after the customer enters the opt out program.

Additionally, I am recommending changes both to the overall program cap and the participant eligibility requirements. Currently, total participation in the

Five-Year Opt-Out program is subject to a 300 MWa cap. I recommend that if total participation comes within 10 MWa of the cap, that it be converted into an annual program cap of 50 MWa of incremental opt-out load each year. Further, eligibility for the program is currently limited to customers with at least one MWa of aggregated load with each Point of Delivery having a Facility Capacity of at least 250 kW. Going forward, I recommend that the load aggregation minimum be reduced from one MWa to 200 kWa and the minimum Facility Capacity reduced from 250 kW to 30 kW. I believe my recommended changes are better aligned with the intent of Oregon's direct access statutes.

2. RPS/ Direct Access Issues. Currently, direct access customers unreasonably pay for RPS-related resources twice: once to their Electricity Service Supplier ("ESS") and a second time to PGE through the Schedule 128 and Schedule 129 transition adjustments. This "double payment" problem can reasonably be resolved one of two ways, either: (1) by assigning an appropriate value to the Renewable Energy Certificates ("RECs") freed-up by direct access customers in the calculation of PGE's transition adjustments, or (2) by PGE transferring the RECs freed up by direct access customers to be used on behalf of those same customers during the period in which the direct access customers are subject to a transition adjustment. Absent the parties to this case negotiating a resolution to this issue in a stipulation, I recommend that the Commission require PGE to adopt a REC transfer approach that is either identical to, or substantially similar to, the approach that was developed by PacifiCorp stakeholders in a workshop authorized by the Commission in UE 323. The agreed-upon approach in that case reasonably provides for the transfer of RECs from PacifiCorp to ESSs on behalf of direct access customers.

3. ESS Scheduling. PGE proposes to modify its Rule K to allow the Company to ask the Commission to decertify an ESS if the ESS has excessive scheduling imbalances as defined by PGE. PGE's proposal is grossly disproportionate to the problem the Company is alleging and should be rejected by the Commission. Although PGE depicts its chief concern regarding ESS scheduling practices to be a reliability problem, a close inspection of the data reveals that there is no material under-scheduling by ESSs taking place, and that the reliability specter raised by the Company is misplaced.

In seeking a state retail license decertification option relating to ESS scheduling imbalances, PGE gives the appearance of proposing to "work around" prior decisions by FERC which found that CAISO Energy Imbalance Market ("EIM") pricing (assessed to ESSs for their imbalances) is just and reasonable and provides appropriate scheduling incentives. Since PGE's proposed remedy to "improve" ESS scheduling practices appears to be in conflict with FERC's findings about the efficacy of CAISO EIM pricing, it would seem that the appropriate jurisdiction for PGE to raise its concerns regarding the adequacy of EIM price signals is FERC.

<u>Future of the Five-Year Opt-Out Program</u>

Q. What is the purpose of retail direct access and transition adjustments under Oregon's direct access law?

A. Under a retail direct access program, the direct access customer continues to use the utility's distribution system but does not use the utility as its power supplier, but instead obtains energy from another supplier. Oregon's direct access law was initially enacted in 1999. In its findings supporting the legislation, the legislative assembly declared that "retail electricity consumers that want and have the technical capability should be allowed, either on their own or through aggregation, to take advantage of competitive electricity markets as soon as is practicable."[1] The direct access law requires that all non-residential retail customers be allowed direct access to competitive markets by purchasing generation services from Commission-certified electricity service suppliers ("ESS").[2] The law requires the Commission to implement rates that charge or credit the direct access customer an amount that prevents "unwarranted shifting of costs."[3]

Q. By way of background, please summarize the status of direct access in PGE's service territory.

A. Qualifying non-residential customers can participate in one of three direct access options: a One-Year program, a Three-Year program, and a Five-Year Opt-Out program. Each program requires that the participating direct access customer be subject to a transition charge or credit. As of June 2017, 17.2% of PGE's non-residential load was participating in direct access, according to a

[1] Or. Laws 1999, Ch. 865.
[2] *See* ORS 757.600(6), (16), -601(1), -649(1)(a).
[3] ORS 757.607(1), (2).

market status report prepared for the Commission.[4] The large majority of this load is in the Five-Year Opt-Out program.

Q. What is the Five-Year Opt-Out program?

A. Since 2003, PGE has offered a Five-Year Opt-Out program that allows qualifying customers to transition permanently to market pricing. This is the only PGE program that offers a permanent transition to market pricing to existing load without any ongoing payments to PGE for PGE's generation services.[5] It does so by providing a date certain for the termination of the direct access customer's obligation to pay for PGE generation costs through the transition adjustment. PGE's other two direct access programs, the One-Year program and the Three-Year Opt-Out program, each presume a return to cost-of-service rates at the end of the participation period and do not provide any pathway for the permanent cessation of transition adjustment payments.

Currently, the Five-Year Opt-Out program is limited to customers with at least one MWa of aggregated load with each Point of Delivery having a Facility Capacity of at least 250 kW. Total participation in the program is subject to a 300 MWa cap.

Q. How long are Five-Year Opt-Out customers subject to a transition adjustment?

A. Under the current program, a Five-Year Opt-Out customer is subject to a transition adjustment for the first five years after the customer enters the program

[4] Source: Oregon Public Utilities Commission, Status Report: Oregon Electric Industry Restructuring (June 2017). See Exhibit Calpine Solutions/101.

[5] I note that in AR 614, the Commission is considering options for permanent market pricing for qualifying *new* loads.

and thereby commits to not use PGE's generation services. During that five-year period, the participating customer pays the ESS for the generation services that the ESS delivers to PGE's system to serve that customer's load, but the customer also must pay PGE a substantial charge for PGE's stranded generation assets left behind by the customer. That stranded cost charge is calculated through the transition adjustment calculation. In theory, this stranded generation charge could result in a net credit to the direct access customer if projected market prices exceed PGE's projected generation costs, but in practice, current direct access customers are paying net charges for PGE's generation assets through the transition adjustment during the transition period. After the end of those first five years, these customers rely solely on market pricing for their generation service, which is purchased from an ESS such as Calpine Solutions, and have no remaining obligations to pay PGE for any costs of PGE's generation assets.

Q. Can Five-Year Opt-Out customers ever return to cost-based service?

A. Yes, but only with three years' notice.

Q. Have any Five-Year Opt-Out customers ever returned to cost-based service?

A. No. Even though the program has been around since 2003, no Five-Year Opt-Out customer has ever returned to cost-based service to the best of my knowledge.

Q. What is your understanding of the purpose of the transition adjustment that is paid by direct access customers?

A. The purpose of the transition adjustment is to provide the appropriate credit or charge for customers who choose direct access service. The credit or charge is intended to approximate PGE's stranded generation costs that should be charged to the departing customer, or conversely to calculate PGE's stranded generation benefits that should be credited to the customer. The transition adjustment is applied either through Schedule 128 or Schedule 129. Schedule 128 is applied to customers who choose a one-year direct access option, while Schedule 129 provides separate adjustments applicable to customers who choose the Three-Year and Five-Year Opt-Out programs.

PGE's transition adjustment calculation is a form of Ongoing Valuation as prescribed in OAR 860-038-0140. According to OAR 860-038-0005(41):

> Ongoing Valuation means the process of determining transition costs or benefits for a generation asset by comparing the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period.

The logical premise behind Ongoing Valuation is to credit or charge direct access customers the difference between market prices and cost-of-service rates for PGE's generation resources. The design logic in this approach places customers in an economically "break even" position with respect to the choice of direct access service; that is, if market prices are below cost-of-service rates at the time the transition adjustment is calculated, the direct access customer is charged the difference via the transition adjustment. Conversely, if market prices are *above* cost-of-service rates, the direct access customer is *credited* the difference via the transition adjustment.

The corollary to this design logic is that it holds non-participating customers harmless, as the utility, which buys and sells billions of kilowatt-hours over the course of a year, should be able to dispose of the energy freed up by direct access through market transactions. Thus, through market sales of energy from PGE's stranded generation assets (or avoided market purchases) and the departed customer's payment of transition adjustment charges, PGE is able to recover any generation costs of resources acquired for that direct access customer before the customer's election to buy generation services from the market. In the case of PGE, the transition adjustment analysis consists of evaluating the impact of incremental direct access load on a 2,500 MWa generation system.

Q. Please explain how direct access can be viable if the design logic of Ongoing Valuation places direct access customers in an economically break even position.

A. For customers who attempt to select direct access service on a year-to-year basis, the Ongoing Valuation approach indeed makes direct access a tenuous value proposition. A one-year direct access selection may be economically viable in certain circumstances, such as, for example, if some market movement occurs during the shopping window, after the transition adjustment has been set. Additionally, other customers may wish to purchase more renewable energy than is available through PGE's cost-of-service portfolio. Alternatively, some customers may have a strong corporate preference for participating in the market, despite the barrier of contending with a "break even" transition adjustment design. But in general, the year-to-year "break even" model is not particularly attractive for customers. In Oregon, the only direct access program that has shown signs of sustained success is PGE's Five-Year Opt-Out program, in which customers pay PGE's Ongoing Valuation transition adjustment for five years, and then migrate fully to market prices for generation (with no further transition adjustments). These customers continue to use and pay for PGE's transmission and distribution network.

Q. How are transition adjustments calculated under the Five-Year Opt-Out program?

A. Transition adjustments for the Five-Year Opt-Out program are calculated in accordance with the design logic discussed above. That is, the transition adjustment is calculated to charge the direct access customer the difference between PGE's cost-based rates and market pricing for generation service for the duration of the five year transition period. For the purpose of this calculation, PGE's cost-based rates are split into two components: variable costs and fixed costs. The variable cost component of the transition adjustment is calculated by taking the difference between (a) PGE's projected net variable power costs (as reflected in the Company's rates) for the five-year transition period and (b) projected market prices for that same period, with the latter adjusted for line losses and wheeling costs. In this manner, the variable cost component of the transition adjustment is "locked in" for the full five-year transition period. On the other hand, the fixed cost component of the transition adjustment moves in tandem with the fixed costs charged to cost-of-service customers over the five year period. That is, the transition adjustment for the Five-Year Opt-Out program charges the direct access customer the same fixed cost for PGE generation that the Company charges to its cost-of-service customers on the same rate schedule, even as that rate may change by Commission order during the course of the five-year transition period. Thus, while it may be slightly counterintuitive, the *variable* cost component of the five year transition adjustment is *locked in* (i.e., is "fixed") for the five year transition period, whereas, the *fixed* cost component "*varies*" from year to year whenever the fixed cost component in rates changes.

Q. Please describe the changes proposed by PGE for the five year transition adjustment.

A. PGE proposes to abandon the Five-Year Opt-Out program and convert it to a ten-year opt-out program by requiring participating customers to pay ten years' worth of transition adjustments, including ten years of PGE fixed generation costs. Although the proposal in PGE's filing lacks much detail, based on the Company's discovery responses, the new ten-year transition adjustment being proposed by PGE would operate the same way as the current Five-Year Opt-Out transition adjustment operates except that it would remain in place twice as long (i.e., ten years instead of five).[6]

Q. What rationale does PGE offer for extending the transition adjustment to ten years?

A. PGE offers two justifications for its proposal. First, PGE asserts that allowing ten years of fixed costs "will help protect remaining [cost-of-service] customers from undue cost shifting" when large nonresidential customers choose to opt out of cost-of-service rates on a long-term basis. Second, PGE states that its

[6] *See* PGE Responses to Calpine Solutions Data Requests No. 001 and 012, included in Exhibit Calpine Solutions/102.

proposal more closely aligns PGE's Schedule 129 transition adjustments with PacifiCorp's long-term opt-out program.[7]

Q. Are PGE's justifications reasonable grounds for increasing the long-term transition adjustments from five years to ten years?

A. No. First, PGE offers no credible evidence that remaining customers are negatively impacted from undue cost shifting when opt-out customers pay transition adjustments for five years instead of ten. The sole "argument" that PGE offers on this score is an unsubstantiated claim that limiting the opt-out transition adjustment to five years causes $76 million in harm to remaining cost-of-service customers in years six through ten. However, this claim is not based on any credible analysis – it is just a simple math calculation unconnected to any semblance of cost causation. The so-called "harm" claimed by PGE is derived by taking the fixed generation cost of $34.60/MWh for Schedule 89-P and multiplying it by 50 MWa of presumed opt-out load each year, which produces an alleged "harm" of $15.2 million per year. When multiplied by five years, the resulting product is $76 million.[8] PGE makes no attempt to ascertain whether opt-out customers are actually *causing* $34.60/MWh in fixed costs in years six through ten. Rather, PGE simply assumes this to be the case and presents nothing more than a mathematical tautology: if the Company were able somehow to recover $15.2 million each year from direct access customers during years six through ten, then it would add up to $76 million over that same period, which, PGE avers, could be used for the benefit of other customers. But PGE fails to

[7] PGE Exhibit 1300, p. 40.
[8] *See* PGE Exhibit 1308.

consider whether there is any good reason to charge the direct access customers this additional amount in the first place.

To see the hollowness of the Company's argument, consider an equally true tautology: if the Company were able somehow to recover $15.2 million more each year from *residential* customers it would also add up to $76 million over five years that could benefit still *other* customers. But the fact that some customers could benefit if residential customers were overcharged is hardly a good reason for the Commission to authorize PGE to do so. The same logic is true for proposals to overcharge direct access customers. The key question is not whether collecting more from one group of customers makes it possible to charge less to another group. All else being equal, that is always the case. The key question is whether there is a sound basis in cost causation to levy additional charges on a particular group in the first place – and that is where PGE's argument to extend the transition adjustment to ten years fails.

Q. Why isn't there a reasonable basis in cost causation to extend the transition adjustment from five years to ten years?

A. The five-year transition adjustment for PGE's opt-out program has been in place since 2003. Nothing has changed to warrant a doubling of the period for assessing transition charges to opt-out customers. The transition adjustment for the opt-out program should be limited to five years because five years gives PGE sufficient time to plan for the exit of the opt-out customer. With five years' notice, there is no reason for PGE to plan to add any new resources to serve the departing load. Indeed, the departure of opt-out load allows PGE to *avoid* adding incremental generation resources that would otherwise be needed to serve the Company's system load. Those new incremental generation resources would otherwise increase the generation costs charged to all PGE customers. This avoided fixed generation cost is thus a *benefit* to PGE's system and the customers who are not participating in direct access. Yet in proposing to extend the transition adjustment to ten years, PGE makes no attempt to recognize this incremental benefit provided by opt-out load; PGE only proposes to keep charging the opt-out load for PGE's fixed generation costs (that the opt-out load no longer uses) in years six through ten after the customer leaves for direct access service – and in so doing never closes the pool of generation resources assessed to the customer. Continuing to charge direct access customers for *new* generation costs six to ten years after these customers have departed for direct access service, which is inherent in PGE's proposal, is unwarranted and unreasonable.

Significantly, the absence of an avoided capacity credit for direct access in the Company's opt-out proposal stands in stark contrast to its recent Voluntary Renewable Energy Tariffs ("VRET") filing, in which PGE proposes to recognize a capacity credit to VRET participants during periods of resource deficiency.[9] In PGE's VRET proposal, the participating customer will receive a capacity credit for its election to participate in the program based on the projected need for capacity on PGE's system as that need exists at the time of the customer's election to participate in the VRET program. In other words, if the customer begins the VRET program in 2019 and the IRP in effect at that time projects a

[9] *See* UM 1690, PGE Exhibit 200, p. 10.

capacity deficiency in 2025, the customer will start receiving a capacity credit in 2025. Evidently, PGE is willing to recognize the concept of avoided fixed generation costs for a program it is seeking to promote, such as the VRET, as distinct from a program that the Company apparently wishes to discourage, such as direct access. PGE's opt-out transition adjustment proposal in this case is one-sided and inequitable toward future opt-out customers and should be rejected by the Commission.

Q. Does information in the Company's IRP indicate that opt-out customers would allow PGE to avoid fixed generation costs six to ten years after opting out?

A. Yes. PGE's 2016 IRP Update filed March 8, 2018 indicates significant remaining capacity deficits after taking into account energy efficiency, demand response, dispatchable standby generation, bilateral procurement, executed contracts, and spot market assumptions. Table KCH-1, below, presents PGE's forecast annual capacity deficits through 2030 based on this IRP update.[10]

[10] Based on PGE's 2016 IRP Update- March 2018 (Docket No. LC 66), Figure 3 on page 18. Numerical values provided in PGE's response to Calpine Solutions Data Request No. 020(a.), included in Exhibit Calpine Solutions/102.

Table KCH-1
March 2018 IRP Update Capacity Deficits

Year	Capacity Need (MW)
2020	0.0
2021	111.8
2022	111.4
2023	108.5
2024	225.7
2025	494.8
2026	732.6
2027	759.5
2028	824.7
2029	937.6
2030	974.9

In discovery, Calpine Solutions asked PGE if it has specific plans to acquire new capacity resources in the 2022 through 2040 period. The Company did not indicate that it has made any specific plans or commitments to acquire new supply-side resources during this period.[11] Thus, PGE has significant flexibility to avoid or defer capacity additions that would otherwise be necessary absent new entrants into the opt-out program.

Q. Have you estimated the value of avoided fixed generation costs that will be made possible by new opt-out customers?

A. Yes. Using the cost assumptions in the Company's IRP, I estimate that opt-out load will be able to avoid incremental fixed generation costs of

[11] *See* PGE's response to Calpine Solutions Data Request No. 020(d.) – (f.), included in Exhibit Calpine Solutions/102. PGE indicates it does not have specific plans for RPS resource acquisitions during the 2022-2040 period, but must meet RPS requirements for cost of service load. PGE also indicates that it is obligated to take energy and capacity from Qualifying Facilities, and provides its forecasted energy efficiency and demand response additions.

approximately $41.77/MWh in 2024, which corresponds to year six for a new opt-out customer entering the program in 2019. Due to depreciation, this value declines to $38.42/MWh in 2028, corresponding to year ten for an opt-out customer entering the program in 2019, assuming the avoided resource would have been added in 2024.[12] This analysis is presented in Exhibit Calpine Solutions/103. These avoided fixed cost values exceed the fixed generation costs calculated by PGE for Schedules 85 and 89, which range from $34.14 to $37.65 per MWh.[13]

Q. How should this information be used in the calculation of the transition adjustment?

A. If the transition adjustment for opt-out service continues to be calculated for five years instead of ten, as I recommend, then there is no reason to use this avoided generation cost information in the calculation of the transition adjustment. However, if the transition adjustment calculation is extended to ten years as proposed by PGE, then the avoided fixed generation costs I discussed above should be credited against the fixed generation charge that PGE proposes to levy on opt-out customers in years six through ten.

Q. How do you respond to PGE's contention that a ten-year transition adjustment should be adopted in its service territory because PacifiCorp's

[12] Derived using the updated supply side resource costs for a combined-cycle combustion turbine (1x1 GE 7HA.01), used in PGE's March 2018 IRP Update. Workpapers supplied in PGE's First Revised Response to Calpine Solutions Data Request No. 020(c.), Confidential Attachment 020-B. My analysis assumed a commercial operation date of 2024 instead of 2021; all other inputs were unchanged. Values provided on a nominal basis, and exclude fixed wheeling costs as a wheeling credit is included in the variable component of the transition adjustment. Although the derivation of my calculation required the use of a Confidential PGE workpaper, PGE has agreed that neither my avoided fixed generation results, nor Exhibit Calpine Solutions/103, in which my calculation is summarized, are confidential.

[13] From the "fixed gen" tab of PGE's workpaper "Ratespread_ 2019 GRC."

opt-out program recovers ten years of fixed generation costs from participants?

A. PGE's arguments concerning PacifiCorp should not be used as the basis for determining the appropriate transition adjustment period for PGE. Each utility's unique circumstances should be considered in determining the appropriate transition adjustment period for its respective long-term opt-out program. Certainly, the Commission did not feel obliged to limit the fixed costs included in PacifiCorp's transition adjustment to five years on the grounds that PGE's recovery was limited to five years. The reverse should also be true. Just because PacifiCorp is permitted to include ten years of fixed cost recovery in its transition adjustment does not mean that PGE should be so allowed, especially since PGE's load and resource circumstances are significantly different.

Q. In what ways are PGE's circumstances today different from PacifiCorp's circumstances when the Commission allowed the latter to include ten years of fixed cost recovery in its transition adjustment?

A. PacifiCorp argued for ten years of fixed cost recovery in its transition adjustment in UE 267, an argument that was accepted by the Commission in Decision No. 15-060 on February 24, 2015. At that time, PacifiCorp was experiencing relatively flat Oregon load growth and had no displaceable generation investments in its planning horizon between 2015 and 2023.[14] In contrast, PGE is experiencing load growth of 1.1% per year [15] and is facing a resource deficiency of 225.7 MW in year six of the forthcoming 2019 opt-out period (2024), with the deficiency increasing to 824.7 MW in year ten (2028). Thus, unlike PacifiCorp at the time its opt-out proposal was being considered, PGE has significant resource needs in years six through ten of its forthcoming opt-out period that can be partially displaced or deferred by new opt-out load. While I disagreed with, and respectfully continue to disagree with the Commission's decision with respect to PacifiCorp, it is clear that the circumstances that applied to PacifiCorp at the time of that prior decision are very different from, and inapplicable to, PGE's circumstances. Moreover, the ten-year fixed generation cost requirement incorporated into PacifiCorp's transition adjustment has contributed to the general failure of that utility's direct access program, whereas PGE's Five-Year Opt-Out program at least has had a modicum of success, garnering far greater participation levels than PacifiCorp's opt-out program. Emulating PacifiCorp's transition adjustment calculation would only serve to unduly thwart new direct access service in PGE's service territory, rather than help implement it in a reasonable manner.

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[14] Order No. 15-060 in Docket No. UE 267, which allows PacifiCorp to recover ten years of fixed generation cost in its transition adjustment, was issued February 24, 2015. PacifiCorp filed its opening testimony in that docket on June 14, 2013 and parties' reply testimony was filed September 13, 2013. Thus, the primary planning context in which that case was conducted was PacifiCorp's 2013 IRP. The 2013 IRP Preferred Portfolio, presented in Table ES.3 on page 11 of the 2013 IRP showed the next planned utility supply side resource after 2014 coming on line in 2024. In Table A.9 of Appendix A of the 2013 IRP, Oregon load growth over the 2013-2022 period was projected to be just 0.48% per year. In January 2015, PacifiCorp released its draft preferred portfolio for the 2015 IRP. By that time, the next PacifiCorp supply side resource had slipped to 2028.

[15] Based on PGE's 2016 IRP Update- March 2018, p. 15. Over 2022-50, PGE projects annual growth rates of 1.1% for energy, 0.8% for winter peak, and 1.1% for summer peak.

Q. Are you recommending any changes to the terms of the Five-year Opt-Out program?

A. Yes. I am recommending changes both to the overall program cap and the participant eligibility requirements.

Q. What changes are you recommending to the overall program cap?

A. As I noted above, total participation in the Five-Year Opt-Out program is subject to a 300 MWa cap. While program participation levels are still reasonably within the cap, I recommend that the Commission adopt a contingency provision for such time as the participation level may approach the cap, e.g., if it comes within 10 MWa of the cap. At such time, I recommend that the total program cap be converted into an annual program cap of 50 MWa of incremental opt-out load each year.[16]

Q. What is the reason for your recommended change to the cap?

A. The current cap is the product of a negotiated settlement agreement. In advancing an innovative program such as the Five-Year Opt-Out, it was reasonable to incorporate a negotiated cap to protect against unforeseen impacts of a sudden migration of a very large amount of customer load to the program. As it turned out, a sudden large-scale migration to the program did *not* occur, but the cap provided the needed reassurance on the front end that allowed the parties to reach agreement on program design. Going forward, if the overall cap were to be reached, it would not be in the public interest to permanently deny new entry to

[16] I note that section II.3(b) of the Stipulation approved by the Commission in UE 236 (establishing going-forward the terms of the Five-Year Opt-Out program) provides a mechanism for accommodating the first customer causing an annual cap to be exceeded. I recommend that the same "first customer over the cap" mechanism be applied to the 50 MWa annual cap I am proposing here.

interested participants. As I noted above, the Five-year Opt-Out is the only PGE program that offers a permanent transition to market pricing for existing load. Permanently denying – or significantly delaying – new entry to interested participants would not appear to be congruent with the intent of Oregon's direct access statutes.

At the appropriate time, converting the overall cap to a 50 MWa annual cap for incremental opt-out load can meet the objective of protecting against unforeseen impacts of a sudden migration of a very large amount of customer load to the program, while at the same time not imposing an unreasonable permanent cap on the ability of Oregon customers to transition permanently to market pricing. I believe my recommended approach is better aligned with the intent of Oregon's direct access statutes.

Q. What changes are you recommending to the participant eligibility requirements?

A. As I noted above, the Five-Year Opt-Out program is currently limited to customers with at least one MWa of aggregated load with each Point of Delivery having a Facility Capacity of at least 250 kW. As noted in PGE Exhibit 1300, this eligibility requirement was put into place to limit the number of accounts that must be separately tracked, thereby helping to mitigate the administrative burden to PGE.[17] However, with the program now well established, I do not believe this rationale is sufficient to deny access to smaller customers going forward. Therefore, I recommend that the load aggregation minimum be reduced from one

[17] PGE Exhibit 1300, pp. 36-37.

MWa to 200 kWa and the minimum Facility Capacity reduced from 250 kW to 30 kW.

Q. Why are these changes to the eligibility requirements reasonable?

A. There are two main reasons to make this change. First, as I discussed above, the Five-Year Opt-Out is the only PGE program that offers a permanent transition to market pricing for existing load. While it may have been reasonable to temporarily exclude smaller customers for administrative reasons while the program was being initiated, it is no longer reasonable to deny these customers the opportunity to permanently transition to market pricing. Oregon law permits direct access service to all non-residential customers. I believe that extending program eligibility to loads of 30 kW and above – which the Commission's rules consider to be large non-residential customers – would better align the opt-out program parameters with the statute than the current limitations do.

Second, in its recent VRET filing, PGE proposes that customers be eligible for participation if their aggregate load exceeds 30 kW – and the Company will even allow smaller individual loads to be aggregated to reach the 30 kW threshold. This is a far more aggressive aggregation provision than the Five-Year Opt-Out program currently has – and is even more aggressive than I am recommending for the Five-Year Opt-Out program going forward. Certainly PGE's VRET proposal demonstrates that the Company has the willingness and capacity to manage smaller customer aggregation for the purpose of program eligibility. Administrative feasibility should no longer be a barrier to smaller customer participation in the opt-out program.

<u>Treatment of Renewable Energy Credits for Direct Access Service</u>

Q. Please describe the issue relating to the Oregon RPS requirements that needs to be addressed in this docket.

A. The Oregon RPS applies to both cost-of-service and direct access customer loads. When direct access customers purchase power from an ESS, the energy provided by the ESS must meet RPS requirements, which as applicable to the PGE service territory, requires that 15% of supply come from qualifying renewable electricity in calendar years 2018 and 2019, 20% of supply come from qualifying renewable electricity in calendar years 2020 through 2024, and 27% in calendar years 2025 through 2029.[18] At the same time, direct access customers pay for the renewable energy that PGE has acquired to meet the RPS for its cost-of-service customers through PGE's transition adjustment.[19] In the case of the Five-Year Opt-Out program, for example, customers opting out later this year would pay projected costs of the existing portfolio of RPS-compliant resources through the transition adjustment through the year 2023. In paying both the ESS and PGE for RPS power, direct access customers are paying twice to meet RPS requirements, a circumstance that I believe is unreasonable and inequitable.

Q. When a customer switches to direct access and acquires its RPS resources from its ESS, what happens to PGE's RPS requirement?

A. When a customer switches to direct access, PGE's RPS obligation is reduced proportionately.[20] Thus, just as the electric energy is freed up when the

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[18] ORS 469A.052(1), 469A.065.
[19] *See* PGE Response to Calpine Solutions Data Request 021(d), included in Exhibit Calpine Solutions/102.
[20] *See* PGE Response to Calpine Solutions Data Request 021(b), included in Exhibit Calpine Solutions/102.

customer moves to direct access, the Renewable Energy Certificates ("RECs") associated with the direct access customer's RPS requirements are also freed up. The freed-up RECs may be banked by PGE for future use, sold, transferred, or otherwise used to meet PGE's RPS requirements for its cost-of-service customers.[21]

Q. Are direct access customers currently compensated for the value of the RECs procured to serve their load by PGE or otherwise allowed to recognize the benefits of those RECs PGE procured on their behalf prior to the direct access election?

A. No. The current transition adjustment mechanisms recognize and credit the customer for the value of the freed-up energy. However, the current regime provides no credit for the value of the freed-up RECs, even though it is indisputable that PGE's portfolio of RPS-compliant resources paid for by the direct access customer will generate RECs.

Q. Do you believe the status quo is reasonable?

A. No. It is not reasonable for direct access customers to be required to pay twice to meet the RPS requirements, and effectively subsidize the cost of RECs for the benefit of cost-of-service customers.

Q. What is the appropriate way to fix this problem?

A. This problem can reasonably be resolved one of two ways: either by assigning an appropriate value to the freed-up RECs in the calculation of the transition adjustment, or by PGE transferring the freed-up RECs to be used on

[21] *See* PGE Response to Calpine Solutions Data Request 021(c), included in Exhibit Calpine Solutions/102.

behalf of the direct access customer during the period that the customer pays a transition adjustment.

Q. Has this issue been addressed in other Commission dockets?

A. Yes. This issue has been litigated extensively in the last three PacifiCorp TAM proceedings, UE 296 ("2016 TAM"), UE 307 ("2017 TAM"), and UE 323 ("2018 TAM"). Over that series of cases, PacifiCorp and Calpine Solutions ultimately agreed that it was reasonable for the value of freed-up RECs to be included in the calculation of the transition adjustment, but the two parties could not agree on a valuation method. Ultimately, the Commission directed PacifiCorp to investigate a REC transfer approach. As the Commission stated in Order No. 17-444:[22]

> We recognize that the valuation of RECs has been a primary point of disagreement among the parties for three TAM proceedings, with parties explaining the REC markets are volatile and illiquid. Parties believe that REC transfers may be a simpler solution, and we are interested in this option. PacifiCorp began working on two proposals for REC transfers before this TAM, and proposes to conduct another workshop on REC transfers before the 2019 TAM. We agree with the company's workshop proposal, and add a requirement for the 2019 TAM. In the 2019 TAM, the company is to present its best proposal for REC transfers, so that parties may weigh in and build a full record on this issue that will enable us to decide whether REC transfers are practical and feasible.

Q. Did the PacifiCorp workshop on REC transfers result in a reasonable approach for REC transfers being developed?

A. Yes. Participants in the workshop – including PacifiCorp, Staff, ICNU, CUB, and Calpine Solutions – agreed on an approach for transferring RECs from PacifiCorp to ESSs to account for the migration of direct access load. This

[22] UE 323, Order No. 17-444 at 19. Footnotes omitted.

agreement is explained on pages 46-47 of the Direct Testimony of PacifiCorp witness Michael G. Wilding in PacifiCorp's UE 339 filing, currently before the Commission.

Q. Do you believe that a REC transfer approach that is identical to, or at least very similar to, the approach negotiated with PacifiCorp is a reasonable way to address this issue for PGE?

A. Yes, I do.

Q. Has PGE expressed a willingness to consider REC valuation in the transition adjustment, or alternatively, adoption of a REC transfer approach?

A. While not committing to any specific details, PGE has stated that the Company "agrees that REC value should be considered within the context of an overall evaluation of transition adjustment obligations" and that PGE is "willing to discuss this issue with parties as part of settlement negotiations to determine an appropriate approach regarding treatment of RECs as it relates to a review of transition adjustment obligations overall including the proposal made by PGE in this case."[23] PGE has expressed a similar position with respect to adoption of a REC transfer approach.

Q. What is your recommendation to the Commission on this issue?

A. Absent the parties negotiating a resolution to this issue in a stipulation in this case, I recommend that the Commission require PGE to adopt a REC transfer approach that is either identical to, or substantially similar to, the approach that was developed by UE 323 stakeholders providing for the transfer of RECs from

[23] *See* PGE Responses to Calpine Solutions Data Request 021(e) and 022, both of which are included in Exhibit Calpine Solutions/102.

PacifiCorp to ESSs on behalf of direct access customers. As I noted above, the details of this approach are described in the Direct Testimony of PacifiCorp witness Michael G. Wilding in PacifiCorp's UE 339 filing.

ESS Scheduling Issues

Q. Please describe the basic construct of how an ESS schedules energy to PGE's system to serve the ESS's customers.

A. The ESS procures energy in the market and must deliver it to PGE's system. To do so, the ESS must arrange the delivery to PGE over the system of neighboring transmission providers, such as Bonneville Power Administration. The ESS arranges point-to-point transmission service to get the energy to a point of delivery on PGE's system. Additionally, the ESS must become a transmission customer on PGE's own transmission system to serve the ESS's customers interconnected to PGE's system. The transmission service offered to ESSs on PGE's system for this purpose is "Retail Network Integration Transmission Service." This service is offered under PGE's FERC-jurisdictional Open Access Transmission Tariff ("OATT"), which is vetted, approved, and regulated by FERC.[24] PGE's OATT describes Retail Network Integration Transmission Service as follows: "The Network Integration Service provided under Part III and Attachment N of the Tariff [i.e., the OATT] required to be taken by those Eligible Customers that provide direct access service to Retail End Users."

[24] PGE's OATT is available online at http://www.oasis.oati.com/PGE/PGEdocs/PGE-8_OATT.pdf.

The ESS must schedule the energy it procures to PGE's system and then the ESS's third-party transmission provider delivers that amount of energy to PGE's system. That same amount of energy is then further scheduled with PGE's transmission function for the purpose of serving the ESS's load interconnected to PGE's system. Because the load varies from hour to hour, it is commonly expected that there will be deviations between the scheduled/delivered amount of energy and the load. PGE serves as the Balancing Authority for the ESS's load and therefore balances the deviations between the scheduled/delivered amount of energy and the actual load in each hour.

Q. Does the FERC-approved OATT address the circumstance in which the amount of energy scheduled/delivered by the ESS deviates from the ESS's actual load?

A. Yes, the OATT specifically addresses this issue. As part of Retail Network Integration Transmission Service, the OATT requires the transmission customer (which is the ESS) to take "Retail Energy Imbalance Service," which is described in Schedule 4-R of Part III of PGE's OATT. It provides: "Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour," and further explains that PGE must offer this service for load within its control area (which is another term for balancing authority).

PGE's Schedule 4-R includes its FERC-approved charges for imbalances, which is determined using locational marginal pricing calculated by the CAISO EIM, in which PGE is a participant.

Q. What concerns has PGE raised with respect to ESS scheduling?

A. PGE states that it does not have a mechanism to enforce reasonable hourly scheduling by each ESS. PGE claims that while ESSs are subject to penalty charges, some are scheduling with reasonable accuracy and some are not. PGE characterizes some ESSs as scheduling energy on a fairly flat basis over a month, largely disregarding the hourly shape of the energy used by their customers.

Q. What has PGE proposed in response to its concerns?

A. PGE proposes to modify PGE's Rule K to allow PGE to ask the Commission to decertify an ESS if the ESS has excessive imbalances as defined by PGE. ESSs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month would receive notification from PGE of the poor scheduling practice. A second occurrence within 12 months would result in PGE requesting the Commission decertify the ESS.

Q, What is your response to PGE's proposal?

A. PGE's proposal to modify Rule K to provide for decertification is draconian and grossly disproportionate to the problem the Company is alleging. I recommend that the Commission reject the Company's decertification proposal.

Q. Why should PGE's decertification proposal be rejected?

A. PGE's decertification proposal is a so-called "death penalty" provision through which an ESS could have its entire business in Oregon shut down if it falls outside the parameters proposed by PGE. It would also leave the ESS's customers scrambling to find a replacement provider of their generation services and upset their long-term reliance on the services contracted for with the nowdecertified ESS. There is no reason to introduce such an unnecessary and severe business risk to the provision of competitive generation services in Oregon.

Moreover, I have questions about PGE's characterization of the issue. Calpine Solutions is by far the largest ESS in PGE's service territory (measured by PGE load served) and has been an active ESS (through its predecessor company names) serving end-use customers in PGE's service territory since 2004. I have also examined Calpine Solutions' imbalance data covering recent months (as provided by PGE) and can find no indication that Calpine Solutions' current scheduling practices would reasonably be a source of PGE's concerns. Presumably, then, PGE's concerns relate to other ESSs serving smaller aggregate loads.

The fact that PGE's concerns are apparently directed to ESSs serving smaller aggregate loads is relevant because schedules are only submitted in whole MWs, and a 1 MW deviation is a greater percentage imbalance for a smaller load than it is of a larger load. For example, if an ESS is serving a total load, say, of only 6 MW, then a 1 MW imbalance would equal 17% of the load, close to the 20% threshold that PGE wants to use to denote poor scheduling practices. While this may be a significant percentage deviation, it hardly constitutes a reliability or financial problem for PGE. To the extent that PGE's claims of "poor scheduling practices" are distorted by imbalance percentages applied to small load sizes, then the Company's depiction of the problem is overstated.

Q. Do you have other concerns about PGE's characterization of the issue?

A. Yes. As I stated above, PGE characterizes some ESSs as scheduling energy on a fairly flat basis over a month, largely disregarding the hourly shape of the energy used by their customers. This gives the impression that some ESSs are not even bothering to differentiate their schedules across the hours of the day. However, I have had the opportunity in discovery to examine the scheduling and imbalance data for the five active ESSs and observed that none of them with significant load are simply submitting flat schedules. So while some ESSs may not be balancing their schedules as well as PGE would like, those with significant load appear to be making an attempt to vary their schedules to match load to some degree.

Further, my own close examination of the PGE imbalance data applicable to Calpine Solutions that was used by PGE to illustrate the "scheduling problem" in Table 8 of PGE Exhibit 1300 revealed that the December delivery data used by PGE to measure imbalances was preliminary in nature. Using more updated (and accurate) delivery data reduces the depiction of the December imbalance attributable to Calpine Solutions, a correction that PGE has confirmed. PGE corrected its Table 8 in its Response to Calpine Solutions Data Request Number 025, which is included in Exhibit Calpine Solutions/102.

Q. Have you examined the hourly deviations of ESS schedules in the aggregate?

A. Yes, I have. Table KCH-2, below, reproduces PGE's Table 8, as subsequently corrected in discovery, while Table KCH-3 shows the same results on an aggregated basis for the four largest ESSs depicted by PGE. This comparison shows that when viewed in the aggregate, the percentage deviations are significantly less pronounced than the individual results reported by PGE. This is an indication that PGE is overstating the extent of the alleged problem at the system level.

Table KCH-2
Percent of Hourly Deviations Greater than 20%
PGE Corrected Table 8[25]

	Dec-17	Nov-17	Oct-17
ESS-1	11.4%	5.5%	6.9%
ESS-2	0.3%	0.0%	9.3%
ESS-3	30.5%	0.0%	0.9%
ESS-4	33.3%	19.2%	38.4%
ESS-5	N/A	N/A	N/A

Table KCH-3
Percent of Hourly Deviations Greater than 20%
PGE Corrected Table 8 - Aggregated

	Dec-17	Nov-17	Oct-17
ESS 1-4 Comb.	0.0%	0.0%	4.6%

Q. Do you believe that the scheduling practices of ESSs are causing a reliability problem for PGE?

A. No, even though PGE depicts reliability as being one of its chief concerns with regards to ESS scheduling practices. PGE asserts:

> [P]oor scheduling may affect PGE's reliability. PGE is ultimately responsible to serve all customers, including direct access customers. If PGE faces a system or regional emergency such as when a plant goes offline, PGE must find the energy to fill the gap. PGE needs each ESS to schedule accurately so that they are covering the energy needs of direct access customers. In the case of a regional emergency, the market may not have energy available, and poor ESS scheduling will make an already bad situation worse.[26]

Q. Why do you believe that the scheduling practices of ESSs are not causing a reliability problem for PGE?

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[25] See PGE's response to Calpine Solutions Data Request No. 025, included in Exhibit Calpine Solutions/102.
[26] PGE Exhibit 1300, p. 42.

A. Scheduling imbalances can be caused either by over-scheduling (i.e., the ESS scheduling/delivering to PGE's system more power than is required to serve the ESS's load in a given hour) or under-scheduling (i.e., the ESS scheduling/delivering less power than is required to serve the ESS's load in a given hour). To cause the reliability problems that PGE describes above, ESSs would have to be significantly under-scheduling because it is only in the under-scheduling scenario that PGE may need to procure energy from the market. In the over-scheduling scenario, PGE could readily cure the problem by simply backing down its own flexible generation resources. To ascertain the extent of the alleged reliability risks described by PGE, Calpine Solutions asked PGE in discovery to restate the imbalance information presented in PGE Exhibit 1300, Table 8, but limited only to under-scheduling. Table KCH-4, below, is directly comparable to Table KCH-2, above (which reproduces PGE's Table 8, as subsequently corrected in discovery) but is limited to under-scheduling deviations.

Table KCH-4
Percent of Hourly Deviations Greater than 20%
Under-Scheduling Only[27]

	Dec-17	Nov-17	Oct-17
ESS-1	5.4%	0.1%	0.0%
ESS-2	0.0%	0.0%	0.1%
ESS-3	0.0%	0.0%	0.0%
ESS-4	0.0%	0.0%	0.0%
ESS-5	N/A	N/A	N/A

[27] Data source: PGE response to Calpine Solutions Data Request No. 024, included in Exhibit Calpine Solutions/102.

It is evident when comparing Table KCH-2 – which includes over-scheduling and under-scheduling – to Table KCH-4, which is limited to under-scheduling, that ESS under-scheduling is *not* occurring to any significant degree. The data show conclusively that to the extent that ESSs "miss" their schedules, they are clearly erring on the side of over-scheduling, i.e., providing more power to PGE's system than their customers' load. In this case, PGE can simply back down its own generation and has no need to procure additional power from the market. The specter raised by PGE of reliability problems caused by ESS under-scheduling and the alleged need to procure additional power on the market is revealed to be a red herring; this specter is not a valid rationale for introducing a decertification provision into Rule K.

Q. Are there potential problems with ESS over-scheduling?

A. When an ESS over-schedules, its imbalance is cleared through the CAISO EIM at prices determined to be just and reasonable by FERC. As I noted above, PGE's FERC-approved OATT relies on this CAISO EIM pricing for imbalances. Notably, FERC has found that the CAISO's locational marginal pricing for imbalances is an adequate inducement for the customer to act in accordance to market rules.[28] Therefore, as a general proposition, a FERC-approved mechanism already exists for properly pricing imbalances, including over-scheduling, and incenting good scheduling practices. In seeking a state decertification option relating to ESS imbalances, PGE gives the appearance of

[28] See *Arizona Public Service Company EIM Order*, 155 FERC ¶ 61,112 at pp. 40-41. Issued April 29, 2016.

proposing to "work around" prior decisions by FERC finding that CAISO EIM pricing is just and reasonable and provides appropriate scheduling incentives.

In discovery, PGE could only provide a theoretical example of a potential financial impact that could occur from ESSs over-scheduling. The theoretical example was limited to a circumstance in which "the PGE EIM Entity cannot resolve power balance infeasibilities, and the CAISO market software may apply the power balance constraint at the relaxation parameter value (i.e., $1,000/MWh for under-generation and $-150/MWh for over-generation) to resolve the infeasibility." In this special circumstance, PGE claims that if the ESSs have over-scheduled and PGE generation were forced to back down, under-scheduling charges would be applied to PGE load (and customers) and over- scheduling credits would be applied to ESSs.[29] However, it is not clear from PGE's response how rare or common this circumstance is, and PGE has not provided any evidence that it has experienced any actual financial impact arising from ESS over-scheduling.

If PGE is seriously concerned with the compensation it receives under its FERC tariff and the tariff's inability to deter conduct that might cause a reliability problem, it seems that the proper forum for such a complaint is FERC, not this general rate case proceeding. PGE's fundamental complaint here is the proper level of charges and penalties for transmission scheduling imbalances. Those are matters within FERC's exclusive expertise, which are governed by FERC-approved tariffs.

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[29] See PGE Responses to Calpine Solutions Data Requests No. 016(d.) and 023, included in Exhibit Calpine Solutions/102.

Q. Does this conclude your opening testimony?

A. Yes, it does.

Docket No. UE 335

EXHIBIT

Calpine Solutions 101

Status Report

Oregon Electric Industry Restructuring

(Number of Participating Customers as of June 2017)

Status Report

Oregon Electric Industry Restructuring
(Number of Participating Customer as of June, 2017)

Portfolio Options*	PGE	PP&L
Fixed Renewable	8,762	12,024
Renewable Usage	154,838	40,914
Habitat		5,772
Habitat Rider**	9,453	
Time-of-use	5,764	1,506
Eligible Customers	853,859	582,871

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** Habitat Rider is available to existing renewable customers only, and should not be included in calculation of total renewable enrollment numbers.

Direct Access and Standard Offer Service

Certified Electricity Service Suppliers: 6
Registered Electricity Service Aggregators: 12

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	81.5%	1.3%	17.2%
PP&L	95.0%	0.3%	4.7%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Energy Resources & Planning
(503) 378-6917

Docket No. UE 335

EXHIBIT

Calpine Solutions 102

PGE Responses to Data Requests Referenced in Testimony

April 9, 2018

TO: Greg Bass
Calpine Energy Solutions, LLC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to Calpine Energy Solutions, LLC's Data Request No. 001
Dated March 26, 2018

Request:

Reference PGE/1300, Macfarlane-Goodspeed/40-41, discussing the proposal to "Modify the Schedule 129 transition adjustments to reflect 1 ten years of fixed generation costs over ten years, with annual updates to fixed generation costs to reflect actual costs." Please provide a sample calculation of PGE's proposed transition adjustment charge with all work papers and supporting data included.

Response:

PGE has not prepared sample work papers. However, the calculation for transition adjustments for ten years would use the same method currently used, but for ten years rather than five.

April 10, 2018

TO: Greg Bass
Calpine Energy Solutions, LLC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to Calpine Energy Solutions, LLC's Data Request No. 012
Dated March 27, 2018

Request:

Reference PGE/1300, Macfarlane-Goodspeed/40-41, stating that the current direct access program results in harm to remaining COS customers of $76 million and providing such alleged calculation in Exhibit 1308.

a. **Please provide all work papers and documents supporting this assertion and the assumptions underlying the Exhibit 1308.**
b. **Is the assumption in Exhibit 1308 that the 50 aMW customer(s) is opting out for service commencing in year 2019? If not, please identify the assumed year of commencement of service in the direct access program for the 50 aMW customer(s) in the exhibit.**
c. **Isn't it true that PGE is allowed to update fixed generation costs to the customer for the first five years of service, or through 2023 for service commencing in 2019, under the currently approved five-year program?**
d. **Please explain the basis for PGE's table that holds fixed generation costs constant for five years in Exhibit 1308 when in fact PGE's currently approved five-year opt-out program does not hold fixed generation costs constant for those five years.**

Response:

a. See PGE Exhibit 1308.
b. The fixed generation figure of $34.60/MWh for Schedule 89-P is based on the fixed generation in PGE's UE 335 filing for 2019. For purposes of this analysis, PGE believes it is a reasonable proxy for the fixed generation for 2020.
c. Yes. PGE Exhibit 1308 is provided as an estimate of fixed generation over ten years. Under both the current and proposed programs, PGE would update fixed generation costs during the relevant period.
d. For purposes of the analysis in Exhibit 1308, PGE assumed a constant fixed generation figure over the relevant period. As indicated in PGE Exhibit 1300 page 41, the fixed generation assumption in PGE Exhibit 1308 is likely to be understated as is the harm to remaining COS customers associated with the current five-year program. In practice, PGE would update fixed generation in years two through ten, just as it updates fixed generation in years two through five under the current mechanism.

April 30, 2018

TO: Gregory Adams
Richardson Adams, PLLC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to Calpine Energy Solutions, LLC's Data Request No. 016
Dated April 17, 2018

Request:

Reference PGE's response to Calpine Solutions' DR 008(b), stating: "PGE's cost of service customers may be harmed if the energy market is not available to provide energy based on poor scheduling practices of an ESS."

a. **Identify all times in the past decade when the energy market has not been available to supply energy in the quantities roughly equivalent to the scheduling errors PGE has experienced with ESSs.**
b. **Identify all reliability problems that have occurred in the last decade related to poor scheduling practices of ESSs, including date, nature of the problem, and PGE's solution to the problem.**
c. **Identify all instances where cost-of-service customers were curtailed due to poor scheduling practices by an ESS (or ESSs), including the date, and amount of cost-of serve load curtailed, and the details of the occurrence.**
d. **Does PGE agree that participation in the Energy Imbalance Market will decrease the likelihood that energy will be unavailable to supply imbalance service required by ESSs' scheduling errors. Please explain the basis for the response.**

Response:

a. PGE objects to this request on the basis that it is overly broad and unduly burdensome. PGE does not align ESS deviations to the requested detailed market information on an hourly basis. Without waiving its objection, PGE responds as follows:

   PGE has a reliability obligation to ensure that the supply of the energy on its grid is balanced to its load. When this does not occur, it can result in voltage problems, frequency deviations, and in the worst case, breaker open curtailments. PGE's obligation under the NERC Reliability Criteria is to avoid these types of events.

   As provider of last resort, when schedule and actual deviations occur, PGE responds by making economic transactions/dispatches, if possible. However, because PGE is responsible for ensuring that load and generation are in constant balance, actions may be taken that are uneconomic if necessary to ensure reliability.

If the energy market (including PGE's own generation) could not cover a sustained under-scheduling error of any size, the grid operator would ultimately have to curtail load after other contingency reserves were exhausted. Because this is not a situation that is desirable to any of the organizations involved, NERC has taken steps to ensure that there are neighboring sources of energy supply that may be called upon during constrained system operations that may normally not be available in the typical markets at substantial cost. This tiered reliability protection has prevented many curtailments in the West, which PGE has exercised as recently as 2016 when market supply was significantly constrained.

b. PGE objects to this request on the basis that it is overly broad and unduly burdensome. The definition of "reliability problems" is unclear as stated in the question. Without waiving its objection, PGE responds as follows:

There are reliability events that trigger multiple levels of response by PGE and the neighboring grid operators and energy suppliers. At this time, PGE does not investigate reliability events to the level of detail to assign cause specifically to ESS scheduling behaviors. However, as provider of last resort, PGE is aware that poor scheduling practices with ESS entities could contribute to decreased reliability and includes this consideration in its planning for load following reserves to ensure these issues are minimal. Thus, a lack of reliability events does not indicate that ESSs are submitting reasonable schedules.

c. As mentioned in response to part (a), PGE is obligated to ensure supply equals demand per the NERC Reliability Criteria. While PGE has not been forced to curtail loads on its system, PGE has triggered criteria set forth in the Reliability Coordinator's Operating Procedure (OP-301) for Capacity and Energy Emergencies to ensure that there is enough supply to meet demand.

d. PGE objects to this request on the basis that it is seeking opinion and calls for speculation. Without waiving its objection, PGE responds as follows:

No, PGE does not agree. PGE's participation in the Energy Imbalance Market (EIM) provides an additional source of imbalance management to the PGE grid. Before EIM, the PGE grid operators utilized existing generation to balance hourly and 15-minute scheduling discrepancies in real time. The EIM market is using those existing generators as well as neighboring (i.e., non-PGE grid) generators, within the EIM transfer capability available between the neighbors. Thus, the EIM provides a new imbalance supply source. However, this source comes with market design constraints that can heavily influence the economics of the imbalance energy source in ways that have not been previously observed. For example, PGE EIM Entity, i.e. the transmission provider in performance of its role as an EIM Entity under the Market Operator Tariff and PGE's Open Access Transmission Tariff, aims to balance projected load and supply within +/- 1% ahead of each operating hour. During the operating hour, there can be instances when the PGE EIM Entity cannot resolve power balance infeasibilities, and the CAISO market software may apply the power balance constraint at the relaxation parameter value (i.e., $1,000/MWh for under-generation and $-150/MWh for over-generation) to resolve the infeasibility. In these instances, allocation of the cost is dependent on the schedules submitted by an ESS and PGE. If the ESSs have over-scheduled and PGEM generation was forced to back down, under scheduling charges would be applied to PGE load (and customers) and over scheduling credits would be applied to ESSs.

May 24, 2018

TO: Gregory Adams
Richardson Adams, PLLC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE *First Revised* Response to Calpine Energy Solutions, LLC's Data Request No. 020
Dated May 24, 2018

Request:

PGE/1300, Macfarlane-Goodspeed/39-41 discusses PGE's transition adjustment and PGE's resource needs of the next few years. Reference PGE's 2016 IRP update, filed March 8, 2018 in Docket No. LC 66.

a. **Please provide the numerical capacity deficit amounts in MW for each year 2020 through 2040 underlying Figure 3 on page 18.**
b. **Have there been any updates to the capacity deficit amounts reflected in Figure 3 since PGE filed its March 8, 2018 IRP update? If so, please provide the updated annual capacity deficit amounts in MW.**
c. **Please provide the workpapers in Excel format used to derive the Updated Real Lev. Fixed Cost ($/kW-year) for each resource in Table 7 on page 26. This workpaper should separately state the nominal annual cost components as applicable (fixed capital carrying cost, depreciation expense, fixed O&M, fixed gas transportation wheeling, ongoing capital additions, land lease payments and any other components), and should demonstrate how the real levelized fixed cost is derived using the discount rate and inflation rate assumptions.**
d. **Does PGE have specific plans to acquire new capacity resources in the years 2022-2023? If so, please identify the new resources PGE plans to acquire, provide the projected in-service dates and nameplate capacity, and describe the actions taken by PGE thus far to accomplish that acquisition.**
e. **Does PGE have specific plans to acquire new capacity resources in the years 2024-2028? If so, please identify the new resources PGE plans to acquire, provide the projected in-service dates and nameplate capacity, and describe the actions taken by PGE thus far to accomplish that acquisition.**
f. **Does PGE have specific plans to acquire new capacity resources in the years 2029-2040? If so, please identify the new resources PGE plans to acquire, provide the projected in-service dates and nameplate capacity, and describe the actions taken by PGE thus far to accomplish that acquisition.**

Initial Response (dated May 1, 2018):

a. Attachment 020-A provides PGE's capacity deficit amounts from 2020 through 2040.
b. No, PGE has not updated its capacity need analysis since the March 8, 2018 IRP Update filing.
c. PGE objects to this request on the grounds that it requests IRP models that were not used to prepare PGE's general rate case filing and are, therefore, not relevant to this docket. PGE provided the requested IRP revenue requirements model confidentially as part of discovery associated with Docket No. LC 66 under Protective Order No. 16-408.

Parts (d), (e), and (f):

At this time, PGE does not have specific plans for RPS resource acquisitions through the periods specified. However, PGE must forecast for the increasing RPS requirements beginning in 2025 through 2040. Those RPS requirements will need to be met for existing cost of service load.

PGE does plan to acquire cost-effective energy efficiency resources, as forecasted by the Energy Trust of Oregon. The current forecast for energy efficiency resources includes 54 MWa of additions over the period 2022-2023, 131 MWa of additions over the period 2024-2028, and 283 MWa of additions over the period 2029-2040.

In addition, PGE plans to acquire cost effective demand response resources. The current forecast for demand response resources includes 42 MW of additions over the period 2022-2023, 39 MW of additions over the period 2024-2028, and 14 MW of additions over the period 2029-2040.

Finally, PGE is also obligated to take energy and capacity from Qualifying Facilities regardless of whether these resources are included in PGE's resource plans.

First Revised Response (dated May 24, 2018):

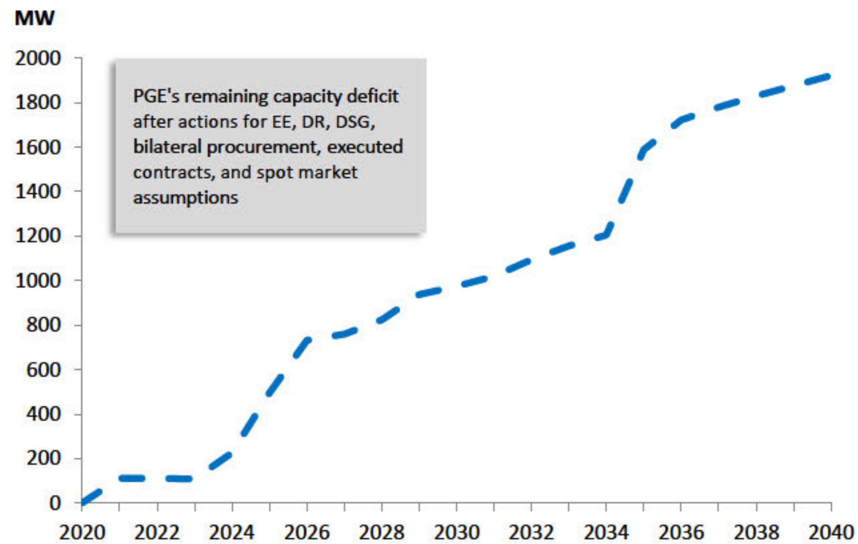
PGE is revising its initial response to part (c). Confidential Attachment 020-B provides the requested work papers for the March 8, 2018 IRP update.

Attachment 020-B is protected and subject to Protective Order No. 18-047.

UE 335 PGE Response to Calpine DR No. 020
Attachment 020-A
Page 1

Year	Capacity Need (MW)
2020	0.0
2021	111.8
2022	111.4
2023	108.5
2024	225.7
2025	494.8
2026	732.6
2027	759.5
2028	824.7
2029	937.6
2030	974.9
2031	1019.6
2032	1093.7
2033	1156.3
2034	1204.3
2035	1588.7
2036	1722.4
2037	1780.4
2038	1829.6
2039	1875.7
2040	1921.6

Figure 3: Annual Capacity Deficit



May 8, 2018

TO: Gregory Adams
Richardson Adams, PLLC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to Calpine Energy Solutions, LLC's Data Request No. 021
Dated April 24, 2018

Request:

Reference PGE/1300, Macfarlane-Goodspeed/41, lines 2-7.

a. **Does PGE agree that when a customer selects direct access service, PGE is not responsible for providing RPS resources to that direct access customer for as long as the customer remains on direct access service? If not please explain why not.**
b. **Does PGE agree that when a customer selects direct access service, PGE's obligation to meet its RPS requirements is reduced in proportion to the direct access load? If not please explain why not.**
c. **What does PGE do with the Renewable Energy Credits ("RECs") that are freed up when a customer elects direct access service?**
d. **Does PGE agree that a new direct access customer would pay for PGE's RPS resources through the transition adjustment? If not, please explain why not.**
e. **Does PGE agree that it would be reasonable to provide a credit to direct access customers for the value of RECs that are freed-up as a result of their selection of direct access service? If PGE disagrees, please explain the basis for the disagreement. If PGE agrees, please explain how this value should be calculated.**

Response:

a. Yes, PGE agrees.
b. Yes, PGE agrees.
c. PGE does not assign specific RECs to individual customer accounts. RECs that are acquired by PGE may be either banked, sold, transferred, or otherwise used to meet PGE's RPS requirements.
d. Yes, PGE agrees that the transition adjustment obligation is inclusive of RPS eligible resource costs.

e. PGE agrees that REC value should be considered within the context of an overall evaluation of transition adjustment obligations. We are willing to discuss this issue with parties as part of settlement negotiations to determine an appropriate approach regarding treatment of RECs as it relates to a review of transition adjustment obligations overall including the proposal made by PGE in this case.

May 8, 2018

TO: Gregory Adams
Richardson Adams, PLLC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to Calpine Energy Solutions, LLC's Data Request No. 022
Dated April 24, 2018

Request:

Please see the attached excerpt from pages 46-47 of the Direct Testimony of PacifiCorp witness Michael G. Wilding in Docket No. UE 339, describing the REC transfer arrangement developed by PacifiCorp stakeholders.

a. **Is PGE willing to agree to the same or substantially similar arrangement?**
b. **If not, please explain why not.**
c. **If PGE would agree to a modified version of the PacifiCorp arrangement, please describe in detail the modifications that PGE would propose.**

Response:

PGE objects to this request on the basis that it calls for speculation and asks PGE to provide its opinion for including a new modification in its direct access program. Without waiving its objections, PGE replies as follows:

PGE is aware of the general terms agreed to by stakeholders in the PacifiCorp docket. We are willing to discuss this issue with parties as part of settlement negotiations to determine an appropriate approach regarding treatment of RECs as it relates to a review of transition adjustment obligations overall including the proposal made by PGE in this case.

May 21, 2018

TO: Gregory Adams
Richardson Adams, PLLC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to Calpine Energy Solutions, LLC's Data Request No. 023
Dated May 7, 2018

Request:

Reference PGE/1300, Macfarlane-Goodspeed/42, at Table 8. The table of ESSs' hourly scheduling deviations of greater than 20% includes overall deviations. Please explain whether the potential harm and risk to PGE and its cost-of-service customers is equal in the circumstances of (i) an ESS being long (i.e. scheduling and delivering more energy than actual ESS customer load) and (ii) an ESS being short (i.e. scheduling and delivering less energy than actual ESS customer load). Please explain the basis for the answer.

Response:

PGE has not quantified and compared the potential harm and risk to PGE and its cost-of-service (COS) customers in circumstances of long or short scheduling by an ESS. In general, all scheduling deviations by an ESS have the potential to create adverse impacts to reliability and may result in financial consequences. PGE as the Balancing Authority (BA) must ensure that its load is balanced with supply. Thus, the BA may need to ramp up or ramp down additional generation to accommodate ESS scheduling deviations, as necessary. While minor scheduling deviations are expected, consistent and excessive deviations are problematic. The impacts to PGE and its COS customers will vary depending on the market conditions during such ESS scheduling events. Please see PGE's response to Calpine Energy Solutions, LLC's Data Request No. 016 for an explanation of reliability concern and imbalance implications.

May 21, 2018

TO: Gregory Adams
Richardson Adams, PLLC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to Calpine Energy Solutions, LLC's Data Request No. 024
Dated May 7, 2018

Request:

Reference PGE/1300, Macfarlane-Goodspeed/42, at Table 8. Please reproduce the table reflecting only the percent of hourly deviations of greater than 20% in the hours where the ESS in question was short (i.e. scheduling and delivering less energy than actual ESS customer load).

Response:

PGE disagrees with this request because an analysis that considers only circumstances of an ESS being short, or long, will disregard the overall impacts of scheduling deviations.

Notwithstanding its disagreement, PGE provides the table below to reflect the requested changes:

	Dec-17	Nov-17	Oct-17
ESS-1	5.4%	0.1%	0.0%
ESS-2	0.0%	0.0%	0.1%
ESS-3	0.0%	0.0%	0.0%
ESS-4	0.0%	0.0%	0.0%
ESS-5*	N/A	N/A	N/A

*Proposed scheduling requirement is not applicable to an ESS with less than ten MWa of energy.

May 25, 2018

TO: Gregory Adams
Richardson Adams, PLLC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to Calpine Energy Solutions, LLC's Data Request No. 025
Dated May 14, 2018

Request:

Refer to PGE/1300, Macfarlane-Goodspeed/42, Table 8, lines 2-7.

a. **Does PGE agree that the "Delivered" data used to prepare Table 8 was preliminary and has been subsequently updated?**
b. **Does PGE agree that if the "Delivered" data used to prepare Table 8 was updated to the more recently available data, the number of hours with imbalance greater than +/- 20% would be reduced for Calpine Solutions? If no, please explain why the number of hours greater than +/-20% would not be reduced.**
b. **Please prepare an updated Table 8 using the most recent data available.**

Response:

a. Yes, PGE agrees. PGE was unaware that a metering issue had caused under reporting in the historical data that was used to prepare Table 8.
b. PGE confirms that only one ESS listed in Table 8 was affected. The corrected data reduces the number of hourly deviations greater than 20% of the scheduled amount for ESS-2.
c. An updated Table 8 reflecting the corrected data is provided below:

	Dec-17	Nov-17	Oct-17
ESS-1	11.4%	5.5%	6.9%
ESS-2	0.3%	0.0%	9.3%
ESS-3	30.5%	0.0%	0.9%
ESS-4	33.3%	19.2%	38.4%
ESS-5*	N/A	N/A	N/A

*Proposed scheduling requirement is not applicable to an ESS with less than ten MWa of energy.

Calpine Solutions Estimate of Fixed Generation Cost Avoided by 50 MWa of Direct Access Load

	2024	2025	2026	2027	2028
MWa	50	50	50	50	50
Annual Energy (MWh)	438,000	438,000	438,000	438,000	438,000

Load Adjustments (Estimated Peak Demand based on MWa)

485/489 Estimated Load Factor:[1]					
77.25%	65	65	65	65	65

Demand Loss Factor - Primary:[2]					
5.305%	68	68	68	68	68

Nominal Fixed Cost per kW-year[3]						**Total**
1x1 GE 7HA.01 (Combined-cycle combustion turbine)	**2024**	**2025**	**2026**	**2027**	**2028**	**Years 6-10**
Capital[4]	$228.29	$222.97	$216.25	$209.76	$203.46	
Fixed O&M	$9.01	$9.19	$9.37	$9.56	$9.75	
Fixed Gas Transp.	$31.11	$31.73	$32.36	$33.01	$33.67	
Total Fixed Costs Excl.Wheeling	$268.40	$263.89	$257.99	$252.33	$246.88	
Fixed Generation Credit	$18,293,909	$17,986,331	$17,584,278	$17,198,280	$16,827,200	$87,889,997
Fixed Generation Credit $/MWh	**$41.77**	**$41.06**	**$40.15**	**$39.27**	**$38.42**	

Data Sources/Notes
1. Derived from PGE NCP-CP 2019 workpaper.
2. From "losses" tab, Ratespread_ 2019 GRC workpaper.
3. Costs determined using Confidential Attachment 020-B, provided in PGE's First Revised Response to Calpine Solutions Data Request No. 020(c.)
   For this analysis, the commercial operation date of the CCCT was changed from 2021 to 2024; all other inputs were unchanged.
4. Capital costs include property taxes and inventory carrying costs.