BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 2024

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS, Investigation into Long-Term Direct Access Programs	))))))	CALPINE ENERGY SOLUTIONS, LLC'S OPENING COMMENTS

INTRODUCTION

Calpine Energy Solutions, LLC ("Calpine Solutions") hereby submits its opening comments to the Public Utility Commission of Oregon ("Commission") in this proceeding. Calpine Solutions is a national provider of retail energy services. Along with its predecessor entities, Noble Americas Energy Solutions LLC and Sempra Energy Solutions LLC, Calpine Solutions has been a certified electricity service supplier ("ESS") under Oregon law and regulations for almost two decades. Calpine Solutions has actively participated in numerous proceedings related to retail direct access before the Commission and appreciates the opportunity to provide its comments on the topics at issue in this investigation.

The procedural ruling in this proceeding calls for stakeholder comment on several background and policy topics to frame the remainder of the Commission's investigation. The comments set forth below will respond to the issues in the sequence provided by the Parties' Issues List and Phasing Proposal attached to the Administrative Law Judge's procedural ruling dated February 21, 2020.

COMMENTS

1. What are the potential benefits and potential costs to customers from long-term direct access participation? What are the potential cost shifts?

a. Potential Benefits

The potential benefits of direct access are numerous. As Oregon legislature recognized when it enacted the direct access statute, direct access provides commercial and industrial businesses and institutional customers such as colleges and universities with the ability to obtain a competitively supplied electricity product and therefore strengthens the state's competitive position to attract those businesses and help keep the cost of education affordable. Direct access allows these customers to negotiate a customized electricity supply that meets the customer's particular energy needs, sustainability goals and budgetary requirements. At the same time, due to the competitive nature of direct access service, the electric suppliers (or ESSs, in Oregon) compete with each other to supply the products sought by customers at the best prices possible. Thus, the products offered evolve over time in response to changing customer interests. The practical effect is that direct access provides an opportunity for sophisticated customers to negotiate a special contract with their electricity supplier, but unlike traditional special contracts in use by the investor owned utilities ("IOUs"), the Commission does not need to review each and every ESS contract in order to prevent harm to the other customers of the IOU due to the cost protections afforded through the direct access program participation requirements, such as transition charges, limitations on return to cost-of-service supply, participation caps, etc.

Although each customer's chosen electricity product in direct access is unique to that customer, examples of the types of products commonly supplied illustrate the benefits of the program to customers and thus Oregon's competitive electricity markets as a whole. One distinct advantage direct access offers is the ability of the customer to obtain price certainty on its electricity supply over the term of the contract that the customer elects. Through the services offered by ESSs, the direct access customer can avail itself of financial hedging products in order to ensure its electricity costs will not unexpectedly change for a term, up to several years into the future. In Calpine Solutions' experience, customers in some states currently hedge their electricity costs for up to 10 years. This ability to obtain price certainty provides businesses and institutions of higher learning the ability to remove the risk of the regulated electricity rates which allows for longer term cost and budget planning. Additionally, in times of low wholesale electricity market prices, customers can lock in those low prices and improve the financial viability of their business operations. In contrast, similar long-term price certainty is not available with cost-of-service energy supply because, by its nature, the cost-of-service energy supply is subject to regulatory fluctuations that are not financially hedge-able.

Direct access customers can also choose to customize other elements of their electricity supply, including a supply that is tailored to their load shape, load factor, or that aggregates varying load shapes and load factors that exist at the customer's multiple locations. For example, if a business operates at different locations in the IOU's territory, it may use direct access to combine the load at the customer's multiple facilities to procure an aggregated electricity product from the ESS that has a more cost-competitive load shape and load factor than the individual locations individually may possess. By aggregating a customer's loads, efficiencies in pricing and product offerings may be obtained through direct access that are not available through cost-of-service electricity supply.

In recent years, large customers have also increasingly sought to green their electricity supply beyond the traditional least-cost portfolio percentages offered by the IOU, and direct access provides an opportunity for customers to negotiate a customized green electricity supply that meets the customer's sustainability goals while holding other customers of the IOU financially harmless to these decisions. Through direct access, Oregon customers have been able to purchase a lower carbon content energy supply through procurement of regional hydropower.[1] The developer of a data center explained: "We purposely sought the direct access right with the intent to source low-carbon power for our Portland facility[,]" and "we prefer to develop data centers in areas with open and competitive markets."[2] Another example is Apple's procurement of renewable energy supply from newly constructed solar and wind facilities to serve its Prineville data center through direct access, which helps Apple meet its corporate goal of 100-percent renewable energy supply.[3] The Portland Business Journal reported: "Apple's deal breaks new ground in Direct Access in Pacific Power's territory, and, in the process, paves the way for a big swath of new renewable energy to come onto the grid."[4] An Apple representative explained: "To strengthen the connection between Apple and these projects, we use Oregon's Direct Access program to schedule the renewable energy from these projects directly to our data center[.]"[5] Thus, in this case, direct access enables a source-to-sink supply of renewable energy and additionality of new renewable generation to the local grid for customers that wish to go beyond Renewable Portfolio Standard's ("RPS") requirements.

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1 *See* "This Hillsboro data center now gets all its energy from BPA system," *Portland Business Journal* (April 27, 2016), https://www.bizjournals.com/portland/blog/sbo/2016/04/thishillsboro-data-center-now-gets-all-its-energy.html.

2 *Id.*

3 *See* "Exclusive: Apple backing two huge Oregon renewable-energy projects," *Portland Business Journal* (April 23, 2017), https://www.bizjournals.com/portland/news/2017/04/23/exclusive-apple-backing-two-huge-oregon-renewable.html (noting Apple signed PPAs for purchase of 200 MW from the Montague Wind Farm and 56 MW from the Galla Solar Facility, both located in Oregon).

4 *Id.*

5 *Id.*

Additionally, cost-of-service customers can also benefit from a successful direct access program. Similar to the effects of a demand-side management program, direct access reduces or delays the load growth that the IOU must serve with "lumpy" utility generation and transmission facility acquisitions. Cost-of-service customers benefit from the reduced or delayed capacity needs of the IOU and avoid costly incremental generation additions. This is a commonly acknowledged benefit of other load reduction programs that are actively promoted by state policy, such as demand-side management programs. Cost-of-service customers also benefit from the direct access customers' continued payment of the full costs associated with transmission and distribution charges, which supports the IOU's system costs. Additionally, cost-of-service customers benefit from the payment by the direct access customers of five to 10 years of transition charges in Oregon's long-term opt-out programs and ongoing (i.e. never-ending) transition charges in the one-year and three-year programs, even in cases where an argument could be made that no generation resources were necessarily acquired to serve the direct access customer.

Finally, cost-of-service customers may benefit from the economic development that occurs with direct access programs. As noted above, direct access attracts business to the state and provides a competitive economic advantage for Oregon over states that do not offer direct access. The direct access programs attracts businesses to the state that might not otherwise locate, expand, or retain their business in Oregon. This is particularly the case with the New Large Loads Direct Access ("NLDA") program, but is also true more generally of the other direct access programs. Direct access also enables existing Oregon businesses to continue operating or choose to expand their business in the state. These direct access loads strengthen the local economy, tax base, and job opportunities – all of which will indirectly benefit cost-of-service customers living and operating in the IOU's service territory.

b. Potential Costs

In identifying the potential costs to customers associated with direct access, it is important to note that an inadequately designed direct access program could impose unnecessary costs on cost-of-service customers *or* on direct access customers. Frequently, the discussion of "cost shifts" focuses only on costs that could be increased on cost-of-service customers to make up for a claimed revenue shortfall by the IOU, but there can be unjustifiable cost shifts to direct access customers as well.

The costs that could potentially be imposed on cost-of-service customers are increased fixed-cost rates for the utility's generation assets assigned to cost-of-service customers. These fixed costs of generation could potentially increase for cost-of-service customers under the direct access scenario only if all of the following circumstances existed: (i) the utility planned to serve the direct access load and acquired generation assets to do so; (ii) the load stopped paying cost-of-service rates and did not pay adequate stranded cost payments (or "transition charges" in Oregon law) to make up for the anticipated loss of revenue; and (iii) the IOU began under-earning its authorized rate of return as a consequence and sought to increase cost-of-service customers' rates to recoup the shortfall directly caused by the loss of direct access load. In Oregon, this problem is fully addressed through the assessment of substantial transition charges that each direct access customer must pay. In the long-term direct access programs, the direct access customer must pay five years of such transition charges for generation assets they do not use in the case of Portland General Electric Company's ("PGE") program and 10 years of such charges in the case of PacifiCorp's program. In the NLDA program, the customers must pay 20 percent of the utility's fixed generation costs for five years, even though the premise of the program is that the utility did not plan to serve the new large load. In both cases, while the IOU is entitled to collect the transition charge revenue, there is no Commission review of whether the revenue received was warranted to offset under-earnings of the IOU. The utility's collection of transition charges is credited to rates charged to cost-of-service customers. Thus, the risk of IOU under-earning related to the revenue shortfall associated with Oregon's direct access programs to cost-of-service rates is addressed through these transition charges.

Additionally, it is worth noting that this risk of stranded generation costs associated with direct access is indistinguishable from the risk that exists whenever the utility incurs a loss of load for which the utility previously acquired resources to serve. Yet only direct access customers pay stranded cost charges without a review of the IOU's rate of return and whether these revenues are warranted to avoid an increase in cost-of-service rates. Other common ways that fixed costs of generation could be increased for other customers include: (i) a loss of large customers that go out of business or relocate out of the service territory, (ii) customers' participation in net metering or on-site generation which decreases payment for and/or use of utility-supplied energy, and (iii) customers' reduction in their energy use through participation in demand-side management programs. In each of those scenarios, the utility loses load that it may have acquired generation resources to serve and, absent offsetting load growth, will eventually increase the remaining customer's fixed costs for generation to recover its full revenue requirement. None of the customers causing these "non-DA" revenue losses of load pay transition charges or other stranded generation cost charges, even though the losses of load and thus the potential cost shifts can have a substantial impact on cost-of-service rates. Additionally, in many instances with these non-DA types of loss of load, the customer will also reduce its payment for transmission and distribution charges to the utility, resulting in additional cost increases to the other customers, whereas the direct access customers continue to pay their full transmission and distribution charges.

With respect to costs that could be shifted unjustifiably to direct access customers, the most obvious cost occurs when the customer is charged an excessive transition charge that is set higher than the level of the unrecoverable fixed costs directly attributable to the direct access election. As noted above, there may be circumstances where certain direct access customers are required to pay transition charges even though it could not be fairly asserted that the utility actually acquired generation resources to serve the customer, such as in the case of a new large customer moving to direct access immediately but not able to participate in the NLDA program. Another mitigating factor often overlooked in setting high transition charges is the impact of load growth in reducing the risk of increased fixed costs to the cost-of-service customers. Additionally, in light of the fact that numerous other categories of customers also cause other forms of loss of load that result in indistinguishable costs being imposed on other customers, an argument could be made that stranded cost charges assessed to direct access customers are unjustifiable in comparison.

2. How are other states handling customer choice and access to wholesale markets for different customer classes (with a focus on other WECC states)?

According to the Energy Information Administration, seventeen states and the District of Columbia have adopted electric retail choice programs that allow end-use customers to buy electricity from competitive retail suppliers, and in most of these states a majority of commercial and industrial customers have signed up with competitive suppliers.[6] Of these states, thirteen have fully restructured electricity markets with competitive wholesale and retail markets.[7] With respect to focusing on WECC states, the WECC states other than Oregon with some form of retail choice include California, Montana, Arizona, and Washington. However, the market structures and programs in these states are not all necessarily analogous to that in Oregon. Montana and Washington's programs are closed to new participants, and therefore may have limited relevance to Oregon. Arizona's only active programs are limited to a wholesale buy-through program where the customer brings the wholesale purchase arrangement to the utility for the utility to take ownership of the electricity and deliver the power to the customer. California has an active direct access program open to new customers, as well as active Community Choice Aggregation programs, but is also unique from Oregon and other WECC states due to its competitive wholesale market and independently operated transmission system maintained by the California Independent System Operator ("CAISO"). Nevertheless, policies in these other WECC states and elsewhere are informative and could have applicability in Oregon on some points.

The comments below address each of the subtopics regarding other states' policies under retail choice programs. Much of this information is also available in previously compiled reports

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6 *See* U.S. Energy Information Administration, *State Electric Retail Choice Programs Are Popular With Commercial and Industrial Customers* (May 14, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=6250. The report identifies Oregon, California, Montana, Texas, Illinois, Michigan, Ohio, Pennsylvania, Maryland, Delaware, New Jersey, New York, Connecticut, Rhode Island, Massachusetts, New Hampshire, and Maine, as well as the District of Columbia.

7 National Renewable Energy Laboratory, *An Introduction to Retail Electricity Choice in the United States*, https://www.nrel.gov/docs/fy18osti/68993.pdf. This report identifies most of the same states as the EIA report, but also includes Georgia and Virginia as states with partial retail choice programs.

in other states. The California Public Utilities Commission ("CPUC") has recently produced useful reports, including its Customer Choice Report[8] and its subsequently produced Gap Analysis.[9] Additionally, the Staff of the Arizona Corporation Commission ("ACC") recently completed a review of direct access policies throughout the country.[10]

a. Provider of last resort obligations

The provider of last resort obligation (also referred to as "default service") refers to a Load Serving Entity that is available to offer retail service as a safety net for customers whose chosen Load Serving Entity is unable to continue service or, in most states, for customers who elect not to shop for competitively supplied electricity. The provider of last resort could be the interconnected distribution utility or it could be a third-party supplier. If the distribution utility is the provider of last resort, often referred to as default service or standard offer service, protections are often put in place to protect any other customers of the utility from absorbing the costs of the unexpected return of load.

In California, the incumbent regulated utility retains the obligation to serve as the provider of last resort.[11] This is consistent with how most restructured states manage provider of

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8 CPUC, *California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market* (August 2018), https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Cal%20Customer%20Choice%20Report%208-7-18%20rm.pdf (*hereafter referred to as* "*CPUC Choice Paper*").

9 CPUC, *California Customer Choice Project: Choice Action Plan and Gap Analysis* (December 2018), https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy__Electricity_and_Natural_Gas/Final%20Gap%20Analysis_Choice%20Action%20Plan%2012-31-18%20Final.pdf (*hereafter referred to as* "*CPUC Gap Analysis*")

10 ACC Staff, *Retail Electric Competition: Jurisdictional Issues, Recent Events* (February 2012), filed on February 12, 2019, in ACC Docket No. RE-00000A-18-0405 (*hereafter referred to as* "*ACC Staff 2019 Report*").

11 *CPUC Choice Paper* at 64.

last resort obligations as well.[12] In contrast, in Texas's restructured market, the market operator assigns the provider of last resort obligation among multiple competitive retailers, as opposed to assigning the responsibility to a single distribution entity.[13] However, Texas's market is restructured such that the incumbent distribution utility does not serve any retail load. In California, the CPUC implemented re-entry fees to cover administrative and procurement costs to serve the returning load if it migrates back to the IOU when market prices exceed cost-of-service rates.[14] In the case where the market prices exceed the cost-of-service rates, the CPUC implements significant bonding requirements on retail suppliers to protect against the cost risk to cost-of-service customers in the event of a return of customers to the incumbent utility.[15]

In Oregon, the provider of last resort obligations are currently with the interconnected investor-owned electric utility, and the customer returning from direct access must pay a market index price (plus an administrative adder) until any applicable return-to-service notice provisions are met.[16] In the case of the long-term opt-out programs, that means that the customer pays the market index price for three years in the case of PGE or four years in the case of PacifiCorp before it could take service under the utility's cost-of-service rates. Thus, in the case where the market price exceeds the cost-of-service prices, the customer is precluded from paying the lower cost-of-service prices or depleting the utility's least-cost portfolio to the detriment of the remaining cost-of-service customers until the next resource planning cycle. It appears that Oregon's policy of the incumbent utility serving as the provider of last resort is consistent with

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12 *Id.* at 36, 40, 43.
13 *Id.* at 48, 52.
14 *CPUC Gap Analysis* at p. 33.
15 *CPUC Gap Analysis* at p. 34 & n. 7.
16 *See* OAR 860-038-0250, OAR 860-038-0280.

policies in other states where the incumbent utility continues serve load, and it does not appear that any changes are needed.

b. Price disclosure

Price disclosure generally refers to policies some states have put in place to make prices offered through the retail market transparent to customers shopping among many suppliers. Generally speaking, price disclosure is only a concern with residential customers who lack the sophistication and resources to research the various pricing options available and negotiate with retail suppliers. For example, in the CPUC's Gap Analysis, the CPUC expresses the concern that there is no single centralized location for residential customers to compare rates and offerings, including terms of service, of all Load Serving Entities, including the IOUs, and instead the rates must be researched on the various Load Serving Entities' websites.[17] The CPUC's concern has become more prominent with the proliferation of Community Choice Aggregation ("CCA"), and the need of residential customers to determine if they will remain with the CCA or opt-out back to the incumbent utility. However, in general, California does not have detailed consumer protections in place for the sophisticated commercial, industrial or institutional customers. The CPUC has determined that these classes of customers have the necessary resources available to negotiate and enforce the provisions of their retail contracts.

In Oregon, residential customers are currently not allowed to participate in direct access through an ESS, and therefore detailed price disclosure databases and consumer protections that might apply in states with retail access for residential customers are not relevant. The Commission's administrative rules require ESSs to post "estimates of prices for electricity services" on their websites when the utility announces its prices for the upcoming year, and the

[17] *CPUC Gap Analysis* at pp. 41-42.

rules suggest the Commission's website will supply links to all of the ESS and utility websites where all such prices can easily be located.[18] The rules also contain general requirements that ESSs not engage in misleading marketing and advertising, and the rules provide the option for disputes between customers and ESSs to be resolved by the Commission to the extent the dispute is with within the Commission's jurisdiction.[19] However, because Oregon's direct access customers are sophisticated business and institutional entities, there should not be a need for further price disclosure and consumer protection provisions. Indeed, many direct access customers may consider prices paid to an ESS for electric energy to be commercially sensitive information, and the same is often true of the prices paid by an ESS to any other third-party in the wholesale market. Therefore, Calpine Solutions recommends against any changes to Oregon policy on this point.

c. Data disclosure

Data disclosure issues can arise with respect to the balance between protecting the privacy of the individual customer's energy usage data and the need to access that data for legitimate purposes. The CPUC's Gap Analysis notes that in California, the investor-owned utilities are generally barred from sharing a customer's usage data unless it is aggregated with enough other customer's data to mask any individual customer's data.[20] However, California is also exploring ways to share customer usage data with third parties where necessary to achieve greater benefit to customers or the grid, such as sharing the data with distributed energy resource

18 OAR 860-038-0275.
19 OAR 860-038-0420(1), (7).
20 *CPUC Gap Analysis* at pp. 22-25.

providers, demand response providers and Community Choice Aggregators through streamlined customer authorization measures.[21]

Oregon's administrative rules bar the incumbent utilities from sharing historical energy usage and other proprietary data solely with their own affiliates,[22] and the utilities have policies in place to share historical energy usage with qualified ESSs to allow marketing to prospective customers with the customer's consent.[23] Calpine Solutions is not aware of any data disclosure issues that have arisen in Oregon or that warrant revision to the Oregon laws and rules at this time, but reserves the right to respond to comments of other parties on this point.

d. General enforcement authority

In general, the state utility commissions in states with retail choice possess the authority to impose penalties or revoke the certificate of any retail supplier that violates the applicable rules and policies. Oregon's laws and administrative rules are consistent with this enforcement authority, and the Commission has authority to certify ESSs and revoke such certification in the case of a violation of applicable rules or violation of basic consumer protection requirements.[24] Calpine Solutions is not aware of any need to change Oregon's existing rules, but reserves the right to respond to comments of other parties on this point.

e. Pricing of departing load

Calculating the cost of departed load is a complex topic that has been addressed in numerous ways by other states. The goal of any stranded cost charge is to ensure that customers

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21 *Id.*; *see also CPUC Choice Paper* at pp. 25-26.
22 OAR 860-038-0600(1)(e).
23 *See PGE's Electricity Service Supplier's Guide* at 27-29, available at https://www.portlandgeneral.com/business/power-choices-pricing/market-based-pricing/direct-access-operations.
24 ORS 757.649(1)(e);OAR 860-038-0400(14).

who remain with the incumbent utility are not required to pay the costs the utility incurred on behalf of the customers who leave the utility to become customers of a competitive supplier, while at the same time also ensuring that departing customers do not take on costs that were not incurred on their behalf. Different states have addressed this issue by developing various ways to calculate and allocate the unrecoverable, above-market costs of generation supply in the utility's portfolio at the time of the customer's election to purchase generation supply from an alternative supplier. The issue is a frequent subject of administrative and judicial litigation because it is factually and legally complex.

In California, the CPUC has developed a complex rate known as the Power Cost Indifference Adjustment ("PCIA") charge that it assesses to direct access customers and CCA customers.[25] PCIA calculations take an IOU total generation portfolio approach, valuing all the IOU power contracts and utility-owned generation costs at the time the customer leaves IOU cost-of-service (i.e. vintage) and marking those costs to the market prices published by the CAISO annually thereafter. When the market prices are high, the IOU has little stranded costs to collect and the PCIA is lower. When market prices are low, the IOU has more stranded costs and the PCIA is higher. As power contracts expire, they drop from the PCIA calculations and so, over time, the PCIA vintage only values the stranded costs associated with utility-owned generation still in service. Notably, California's PCIA charge may not be directly applicable in Oregon because the magnitude of the incumbent utilities' expected losses of load in California is far greater. The CPUC's Gap Analysis states that loss of load was expected to be up to 80

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25 *See, e.g., CPUC's Choice Paper* at 69.

percent from 2018 to 2021 or 2022 due to rooftop solar, direct access, community choice aggregation, and direct ownership of offsite generation by large companies.[26]

Many other states with retail competition adopted major one-time divestment and valuations of the incumbent utilities' generation assets. But these methodologies are not currently relevant in Oregon where the incumbent utilities retain their generation assets and the obligation to serve customers who choose not to participate in direct access or are not afforded the opportunity.

Oregon currently uses a methodology for assessing transition charges which compares the market value of the energy freed up by the direct access election to the incumbent utility's revenue requirement for the generation producing that increment of energy. In the case of the long-term opt-out programs, the customer pays under this methodology for five years in the case of PGE and 10 years in the case of PacifiCorp, whereas the rate is calculated on a year-to-year basis in the utilities' one-year and three-year direct access programs. One outstanding issue that warrants further consideration in the future is whether the Commission should implement an avoided capacity credit for direct access customers in the transition charges, as was proposed in PGE's last general rate case (UE 335) but left unresolved by the stipulation of the parties in that case.[27] Additionally, AWEC's petition in this case suggests that PacifiCorp's use of a 10-year transition charge calculation is excessive and deterring participation in direct access.[28] Aside from these details in the calculation method, Calpine Solutions generally believes the overall methodology employed in Oregon is reasonable given Oregon's circumstances, but Calpine

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[26] *CPUC's Gap Analysis* at 47.

[27] *In the Matter of Portland General Elec. Co.*, Docket No. UE 335, Order No. 19-129, at 18-19 (April 12, 2019).

[28] *AWEC's Petition* at 5-6.

Solutions reserves the right to respond to proposals made by other parties' position on the point in this proceeding.

f. Market design and alignment with customer choice

It is important for states to design the retail market consistent with the retail choice options to ensure the markets are providing customers with options consistent with state policy. In California, the CPUC acknowledged increasing desire by customers for retail choice and examined whether adjustments to its market design were needed to accommodate new retail choice options and state policy objectives, resulting in the CPUC's Gap Analysis.

The magnitude of the potential load shifts are not as significant in Oregon as California because Oregon has no Community Choice Aggregation and much less rooftop solar penetration than California. However, it is worthwhile to consider whether the market design in Oregon is adequately aligned with customer choice and whether improvements can be made to the market to enable retail choice consistent with Oregon's policy goals. One gap in Oregon's market design and customer preference is the current limitation on participation by smaller commercial customers in Oregon's long-term direct access programs. The programs require a minimum load of 1 MW with limited aggregation by the same corporate entity of meters of at least 200-250 kW. However, Calpine Solutions perceives demand for participation by smaller commercial customers in the long-term direct access programs. Expanding the programs to smaller commercial customers is a subject the Commission could consider in this proceeding.

g. Oversight, compliance and reliability responsibilities

While the state utility commissions typically maintain oversight and compliance responsibilities with respect to the incumbent utilities and the competitive suppliers (discussed above), states may differ on reliability compliance depending on whether the state is located in an organized wholesale market. The issue of reliability and resource adequacy is discussed in more detail below. Generally speaking, because Oregon is not located in an organized market, Calpine Solutions believes it is appropriate for the Commission to oversee reliability and resource adequacy issues. However, this is a complex topic discussed further below.

Additionally, this subtopic could include compliance with the RPS. Compliance with a state RPS will be administered by the agency charged with implementing the state's RPS. In Oregon, the Commission is logically the government authority with jurisdiction over ESSs' compliance with the RPS requirements because Oregon law requires the Commission to implement the RPS compliance requirements.[29]

One policy that is being pursued in California that is also notable in this context is the proposal for the incumbent utility to take on the role of providing a centralized procurement of renewable energy, which is then available for purchase from competitive suppliers. Under this model, the competitive suppliers and their customers could also secure their RPS resources elsewhere, but the centralized procurement would ensure procurement of certain products and state policy goals. This is similar to the model that the CPUC is considering for certain elements of the Resource Adequacy product. In the Gap Analysis, the CPUC considered a centralized procurement by the incumbent utility as one means of harmonizing the state's goals for decarbonization with the goals and utilizing markets to achieve lower costs and retail choice.[30] This model has been used in Illinois and New York where the costs of centralized procurement of renewable and certain reliability products are allocated to market participants, but in these states an independent entity without the profit motives of the incumbent utility conducts the

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[29] *See* ORS 469A.170, 469A.180, 469A.200; OAR 860-083-0350(1)(b).
[30] *CPUC Gap Analysis* at p. 61-62.

centralized procurement.[31] This type of model is intended to mitigate the tension between the need for long-term investment for new renewable generation and the short-term financial incentives of Load Serving Entities operating in a market with retail competition and customer switching.[32] Given Oregon's market structure, the model being investigated by the CPUC with the incumbent utility acting in the central procurement role may make the most sense if the Commission is interested in a centralized procurement program for certain products offered to direct access customers.

h. Capacity and reliability

Capacity and reliability are addressed in more detail below with respect to the resource adequacy topic, including how other regions and states address the issue. To the extent this subtopic is intended to include other subjects, Calpine Solutions reserves the right to respond to comments of other parties on other issues related to capacity and reliability.

i. Cost of legislative requirements

Calpine Solutions understands this issue to ask how other states treat the costs of legislative requirements, such as Oregon's public purpose charge, and whether such charges are paid by customers engaged in retail direct access. In general, Calpine Solutions supports policies that require direct access customers to pay their fair share of legislative directives so long as the direct access customers are also allowed to participate in such programs or otherwise share in the benefits of such programs. In Oregon, direct access customers pay the public purpose charge and the charges of many other legislatively directed programs, either directly through tariffs applicable to the direct access customers or through payment of transition adjustment charges

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31 *CPUC Choice Paper* at pp. 43-46, 64.
32 *Id.*

where such costs are incorporated into the otherwise applicable generation rates. However, Calpine Solutions is open to reexamining the details of this issue in this proceeding with other parties and reserves the right to respond to comments of other parties on treatment of this issue in Oregon.

With respect to demand-side management, Calpine Solutions' experience in California is that direct access customers pay for and may participate in demand-side management programs offered by the state's independent provider of demand-side management programs. Calpine Solutions would support an expansion of participation by direct access customers in Oregon's demand-side management programs, and looks forward to investigating this issue with the other parties and the Commission.

3. Resource Adequacy

a. What is resource adequacy?

Resource Adequacy means having adequate capacity to serve load under most conceivable conditions, at various time horizons. The balancing authority ("BA") that ensures Resource Adequacy can be run by a monopoly utility or it can constitute a market run by an Independent System Operator ("ISOs"). Resource Adequacy regimes require mechanisms for load forecasting and resource and transmission planning and procurement to ensure that forecast requirements can be met.

Resource Adequacy is the culmination of the nexus of the electricity markets and reliability planning, protocols and requirements to ensure that there is sufficient available generation and transmission available to meet system demand plus contingencies at least cost or maximum market benefit.

It should be noted that the Resource Adequacy can be broken down into distinct components, depending on the operations, scheduling or planning time horizons under consideration, which include long-term planning, day-ahead operations, and real-time operations.

b. How is Resource Adequacy provided?

Resource Adequacy is provided by owners of firm capacity resources, including physical generation assets (for both long-term and short-term markets) and Firm Liquidated Damages ("Firm LD") off-system purchase contracts (for short-term markets).

Day-Ahead Operations – The BA sets up the generation and interchange based on the BA's hourly forecasted demand. The BA's forecasted demand is system-wide. It is determined by historical analysis, based on weather, day of the week, holidays, and year-over-year growth. This system-wide demand is allocated to bus locations for transmission analysis. From the forecasted demand, the BA must forecast how it will meet the expected customer demand and provide for reliable operation of the transmission system under BA control, and withstand reasonable system contingencies of generation and transmission system elements, without overloading the system or forcing load to be shed. Reasonable contingencies are forced (or unplanned) outages to any single generation or transmission element. These contingencies are modeled by running a load flow analysis on the effects of an outage of any single contingency, and ensuring Resource Adequacy is available to withstand any single contingency.

The procedures to ensure Resource Adequacy in a vertically integrated monopoly construct are distinct to those in a competitive market construct. Under a vertically integrated monopoly utility, the BA runs a least-cost dispatch based on its available internal generation and off-system resource procurement to meet forecasted load plus contingencies. Under a market construct, the BA uses the market-cleared energy, ancillary services and capacity resources to meet the load and reliability needs. In either case, the BA retains final dispatch authority over all resources.

The BA first generates a preliminary least-cost hourly generation solution based on “unconstrained dispatch” that does not take into account the transmission system limits and capabilities. In the case of a vertically integrated monopoly utility, the unconstrained dispatch is conducted with Unit Commitment/Economic Dispatch software. Unit Commitment/Economic dispatch generation inputs are either the generation characteristics (start-up, no-load, fuel cost, heat rate/incremental cost curves) or market bids and offers and self-schedules. In the case of competitive markets, the BA develops the unconstrained dispatch with Bidding Optimization software utilizing market bids and offers. The least-cost solution in Bidding Optimization software will be an hourly solution to meet hourly forecast but must consider generation characteristics such as start-up and minimum-run times. This least-cost solution is either based on the generation heat rate/incremental cost data of offer curves.

In either case, this preliminary unconstrained dispatch solution must be incorporated into a transmission system model, with the hourly loads and generation injections at the transmission nodes.[33] The generation is revised, based on the transmission constraints. This may require generation at some locations to be increased and generation at other locations to decrease to prevent overloading the transmission system.[34] This is sometimes referred to as Security Constrained Economic Dispatch.

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[33] Transmission nodes are the points of interconnection of the generators to the transmission system, as well as the other high voltages busses within the BA.

[34] Transmission systems are typically not protected from overloads (very sophisticated fault protection). This is required to prevent “cascading” outages of the transmission system under stressed conditions. When a transmission line overloads (carries load beyond its physical operating load-carrying capability), the conductors will heat and anneal, damaging the conductors, and possibly stretching the conductor so it sags, which is unsafe.

The BA must also ensure Resource Adequacy to meet any reasonable contingencies. This may require quick-start generation[35] to be available, additional generation to be committed, and ancillary services needed for real-time operations and dispatch. The next day plan must allow for adequate start-up times for generators. The BA's schedulers confirm schedules with all generators and other market participants as needed, then pass down the dispatch and interchange schedule to the "Real-Time" operators, as well as any other transmission constraints or special operating instructions. In addition to on-system generation, Firm LD off-system purchases are also counted as Firm capacity for Resource Adequacy in the Day-Ahead markets and operations. Firm LD resources have been shown, historically, to have performance that matches or exceeds generation capacity resources.[36] Firm LD resources are also under the BA dispatch, in that the BA is the final approval authority for all interchange schedules imported to serve BA load.

Real-Time operations – The Real-Time BA operator must manage the BA generation, transmission and interconnections on a near real-time basis. The day ahead schedule will provide a plan of generation that not only will cover the forecasted load but will have adequate ancillary services to meet voltage,[37] ramping,[38] and operating reserve[39] requirements needed for reasonable contingencies.

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35 Quick Start Generation is typically combustion turbines, which are offline (not connected to transmission grid) but can be remotely started and ramped up to their based load within 10 minutes.

36 *See* UE 358 Calpine Solutions/200, Bass/8-9.

37 Voltage is an ancillary service provided by generators and other transmission system equipment (such as shunt capacitors and reactors) to maintain voltage support.

38 Ramping refers to the capacity of units under control of the BA to follow the load and intermittent resource deviations, which is measured at a MW/min rate.

39 Operating Reserves is an ancillary service, primarily to manage contingencies. It consists of online (spinning reserves) and offline reserves that can be available within 10 minutes, such as quick-start turbines or dispatchable load.

Energy Imbalance Markets ("EIM"), including the CAISO EIM, have been implemented to provide the resources available for intra-hourly dispatches to follow the load during the hour. Energy imbalance results from the changes in demand during the hour and deviations from scheduled supply and demand. The real time re-dispatch horizon is as short as five minutes, where the system operator must constantly review and re-evaluate system conditions and adjust, using the resources that were made available for the EIM. These resources must specify an offer curve at relevant transmission locations, as well as the amount of electric power available (MW) and ramp rates (MW/min.). Locational clearing prices based on the results of the EIM determine the price paid or received by participants in the EIM based on the clearing prices nexus for bids or offers, as well as the price paid or received for any deviations from day-ahead schedules.

The BA manages the second-to-second fluctuations with Regulation/Automatic Generation Control ("AGC"),[40] where generators under the BA AGC control automatically respond in an economic and ramping capability to respond to Area Control Error ("ACE").[41] The BA must have generation connected to an AGC to automatically dispatch generators up or down. In addition, the BA must have resources to follow the load, ramping up or down to load fluctuations. This has become a larger issue with intermittent generation because the resources under BA control must follow the fluctuations of the intermittent resources. The BA must have

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[40] In markets, the ISO typically bifurcates regulation services to up regulation service (URS) and down regulation service (DRS). This is because the economic incentives can be different for which direction the generator moves from set point.

[41] The ACE requires 3 inputs from metering and schedules: 1) Scheduled Net Interchange vs. Actual Net Interchange, 2) Scheduled vs. Actual Frequency, and 3) Time error.

- ACE = I(a) – I(s) + 10Bf (F(a) – F(s)) + Bt, where
- I = Net interchange (Actual, Scheduled)
- F= Frequency (Actual, Scheduled (typically 60 hz)
- Bf = Frequency bias – this converts hz to MW
- Bt= Time error – this is the accumulation of frequency error.

Resource Adequacy to manage transmission outages and constraints as well. Operating reserve, which is available within 10 minutes typically, based on spinning units ramp rate, or quick-start offline capability, is required to recover from generation contingencies. A BA's Resource Adequacy portfolio must include resources under BA dispatch, regardless of whether Resource Adequacy resources are from markets or monopolies.

However, it is important to note that ESSs in Oregon (and thus direct access customers) already compensate the BA for many or all of these real-time operations through the payment of ancillary service charges assessed through the network transmission the ESS must purchase from the BA of the direct access load under the Open Access Transmission Tariff.

Long-Term Planning for Resource Adequacy – In the longer term, the BA needs to plan for both transmission and Resource Adequacy to meet long-term forecasted loads, considering construction lead times and system maintenance. Annually, the BA needs to review seasonal and monthly peaks to ensure Resource Adequacy, and to coordinate generation maintenance scheduling. Typically, the BA must also have a five-year forecast and plan to address generation retirements, which allows adequate lead time for any necessary new construction of generation and transmission to meet Resource Adequacy shortfalls in the planning horizon.[42]

As noted above, the Firm LD resources can support a BA's Resource Adequacy. In considering the contribution of Firm LDs as long-term capacity resource, the BA or regional entity administering the Resource Adequacy program should ensure that the Firm LD resource has a firm transmission path to the load and should ensure that the Firm LD resource is not

[42] However, the Resource Adequacy plans may include a combination of generation, transmission, imported resources, and may not require any construction.

double counted towards Resource Adequacy requirements in order to ensure there is capacity to support the Firm LD transaction.

c. What regulatory or market structures are used in other states with direct access to ensure resource adequacy?

Traditionally, in states with a vertically integrated monopoly construct, a utility can maintain generation capacity that is not needed and is not normally scheduled except during peak load conditions. These peaking generators cannot make enough money in the energy or ancillary services marketplaces to cover their fixed costs, but the utility will normally recover its capital and expenses for such inframarginal units in rates if allowed by the state utility commission as a prudent resource. Planning for acquisition of such units would occur through an integrated resource planning process overseen by the state utility commission. However, outside of the vertically integrated monopoly construct, Resource Adequacy markets have been created to provide an additional revenue stream to keep these capacity resources available without uplifts or direct payments.

In states with organized wholesale markets, the ISO/Market Operator typically has a Resource Adequacy market secure sufficient capacity. The Resource Adequacy units receive payments either bilaterally or from Resource Adequacy auctions. In return for a capacity payment, the capacity supplier generally agrees to participate in energy and ancillary services markets in the operational time frame. Capacity requirements and procurement may be geographically specific. For example, CAISO has requirements at the system level as well as in specific load pockets. Virtually all ISOs have the capability to contract with specific generators to meet capacity requirements that cannot be met through competitive markets, for example, if a specific requirement can be met only with one specific resource.

In California, the CAISO and the CPUC oversee a bilateral Resource Adequacy market through a bilateral market, where capacity providers, transact with Load Serving Entities to meet Resource Adequacy requirements. Load serving entities covered by these Resource Adequacy requirements include utilities (both IOU and public), Community Choice Aggregators, and Electricity Service Providers (i.e. ESS in Oregon). The Load Serving Entities must demonstrate through compliance filings that they have procured sufficient capacity to meet their forecasted customer load plus reserves as well as sufficient capacity in specific load pockets. Resource Adequacy resources must be registered and certified with the CAISO, and may include both physical generation resources and Firm LD resources with limitations. Specifically, Load Serving Entities regulated by the CPUC are limited in the amount of Firm LD contracts that can count towards a Load Serving Entity's Resource Adequacy showing. Currently, the limitations require that the Firm LD contract must be delivered from outside the CAISO BA and have sufficient CAISO intertie allocations to support the energy deliveries.

In the Midcontinent Independent System Operator ("MISO"), Resource Adequacy is also met through a bilateral market construct and requirements contained in MISO's Module E. Load serving entities demonstrate compliance through filings to demonstrate that their customer load plus reserves has adequate firm resources dedicated to it. In the Northeast markets (PJM, NYISO, NEISO), Load Serving Entities have an annual capacity tag (based on peak load analysis) and are charged this capacity tag amount times the Resource Adequacy rate determined by auction prices. This capacity is called UCAP (Unforced capacity) in PJM, and ICAP (Installed capacity) for NYISO and NEISO. The capacity that a resource can claim is "derated" by its outage history by capacity protocols. Load serving entities can procure capacity (ICAP UCAP, or Resource Adequacy) bilaterally as well as market auctions.

The Southwest Power Pool ("SPP") enables both bilateral transactions and markets for energy and capacity. It runs a coordinated BA, with day-ahead and real-time energy markets, as well as ancillary services markets, but relies solely on bilateral transactions for capacity. The SPP compares market results with their own Reliability Unit Commitment and will dispatch additional resources as needed.

In the Northwest states, Resource Adequacy has not been a major concern in the recent past due to regional capacity surpluses. However, going forward, Resource Adequacy has become a concern for BAs in Northwest states, and developing a coordinated form of Resource Adequacy for the region's BAs would be prudent given upcoming resource retirements and projected capacity shortfalls. A coordinated approach should result in lower overall costs.

In Oregon, with a long history of tightly coordinated operations among the IOUs and federal and municipal entities, a coordinated bilateral market may be preferable to implementing a competitive wholesale market structure through an ISO. One possible framework could be based on the bilateral construct used in the SPP, but coordinated by the Northwest Power Pool ("NWPP"), which is currently working on developing a Resource Adequacy protocol. The NWPP's preliminary assessment late last year astutely identifies three key driving principles and recommendations: 1) the program should take a regional approach; 2) the Resource Adequacy program should be tailored to reflect the specific qualities and characteristics of the Pacific Northwest, including hydro availability, transmission systems, and interconnected operations protocols; and 3) the Resource Adequacy program should not usurp existing authority and responsibility for Resource Adequacy requirements.[43] Such a system should acknowledge the

[43] Northwest Power Pool, *Exploring a Resource Adequacy Program in the Pacific Northwest: An Energy System in Transition* (Oct. 2019), https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf.

different elements of Resource Adequacy and adequately utilize all existing resources and market features available, including the use of Firm LD resources with protections against double counting of resources by different BAs.

Additionally, in the context of imposing Resource Adequacy requirements on direct access customers and/or ESSs, the Commission should be careful not to double charge such entities for services they are already supplying. For example, as noted above, ancillary service charges assessed through the OATT already support the BA's Real-Time BA operations.

The Commission should also be careful not to impose requirements on direct access customers and/or ESSs that are more stringent than those imposed on incumbent utilities themselves. In that regard, while at least one Oregon utility has recently suggested that Firm LD resources cannot support Resource Adequacy, the long-standing practice in the region is to rely on such resources, which was demonstrated by Calpine Solutions in Docket No. UE 358.[44] Most notably, PacifiCorp's recently approved 2019 Integrated Resource Plan ("IRP") identifies plans to rely heavily on short-term market purchases (referred to as "Front Office Transactions") to support significant increments of PacifiCorp's load – indeed quantities that exceed the level of the available direct access programs. PacifiCorp's public statements confirm the conscious decision to rely on these Firm LD resources in the major trade publication *California Energy Markets*' article titled "PacifiCorp Will Use Market Purchases to Help Meet Peak Needs."[45] The article explains: "Without market purchases, PacifiCorp says it will have a summer capacity deficit through 2029, starting with a 746-MW deficit next year and rising to 1,038 MW in 2025

[44] *See Calpine Solutions' Opening Brief*, Docket No. UE 358, pp. 11-13 (Nov. 14, 2019).

[45] Steve Ernst, "PacifiCorp Will Use Market Purchases to Help Meet Peak Needs," *California Energy Markets*, No. 1562, pp. 14-15 (NewsData LLC, Oct. 25, 2019).

and 2,827 MW in 2029."[46] Further, "Market purchases (called front office transactions) give the utility a winter surplus in 2020 of 1,806 MW before dwindling to zero in 2024 and falling into a deficit in 2029 of 399 MW."[47] The article notes that "PacifiCorp's plan for market purchases comes as resource adequacy in the region has become a growing concern."[48] But it quotes PacifiCorp's Rick Link as stating: "We're confident the market will be there."[49] Link further explained: ""We aren't in a crisis mode, but we see a storm on the horizon and we recognize that we need to do something about it. The sky is not falling, we just need to address the issue in the region."[50] Calpine Solutions does not take a position on the merits of PacifiCorp's resource plans, which have historically been approved by the Commission. However, it is clear that the incumbent IOUs in the Northwest have relied, and continue to rely, on short-term market transactions, and the Commission should be careful to ensure that any requirements imposed on ESSs are consistent with these practices in the region.

d. Why is Resource Adequacy important or not important?

Without adequate planning for Resource Adequacy, the balancing authority will not have the mechanisms to bring on additional resources available to meet its forecasted load plus reserves, for both operations and planning. This could leave the system exposed to a circumstance of degraded system reliability and cause additional load shedding, most likely more than dispatchable load available. Thus, Resource Adequacy is critically important.

e. Issues for Further Consideration in the Contested Case Phase

- How Firm LD resources can contribute to Resource Adequacy

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46 *Id.*
47 *Id.*
48 *Id.*
49 *Id.*
50 *Id.*

- How dispatchable load can contribute as Resource Adequacy
- Derating capacity resources based on outages
- Use of bilateral markets versus capacity markets (or both)
- Who runs capacity markets?
- Protocols for capacity resources, such as must-offer requirements

CONCLUSION

Calpine Solutions appreciates the opportunity to submit its comments on the issues under consideration in this proceeding and looks forward to responding to comments of other parties and the Commissioners.

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