CASE: UM 1953
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Cross-Answering and Reply Testimony

July 16, 2020

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. I previously sponsored Staff/200 and Staff/300 in this docket.

Q. What is the purpose of your testimony?

A. I provide Staff's response to PGE/600 and PGE/700, as well as intervenors' opening testimony of Phase II of this docket on all of the issues which remain outstanding in this case.

Q. How is your testimony organized?

A. My testimony is organized as follows:

BACKGROUND

Q. Please provide a general background for this case and the issues at hand.

A. During the 2014 regular session, the Oregon Legislature passed House Bill 4126 (HB 4126). This bill directed the Commission to study the impacts of allowing utilities to offer a voluntary renewable energy tariff (VRET) to customers.[1] In accordance with the direction from the legislature, the Commission opened Docket No. UM 1690 and directed Staff to conduct a study to consider the impact of allowing electric companies to offer VRETs to their non-residential customers.[2] As a part of UM 1690, the Commission adopted conditions that outlined the proper design considerations for any VRET to be found in the public interest. The nine conditions include:

1. Renewable Portfolio Standard (RPS) definitions that must apply to voluntary renewable energy products are for resource type, location, and bundled Renewable Energy Certificates (RECs).
2. VRET options should only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants, unless the participants consent to RECs being retired by the utility or the developer.
3. The year in which a VRET eligible renewable resource became operational should be no earlier than 2015.
4. The VRET program size is limited to 300 aMW for PGE and 175 aMW for PacifiCorp.
5. VRET product design should be sufficiently differentiated from existing direct access programs.

[1] HB 4126 Section 3(2).
[2] *In re Public Utility Commission of Oregon*, OPUC Docket No. UM 1690, Order No. 15-258 at 1 (Aug. 26, 2015).

6. VRET terms and conditions (including the timing and frequency of VRET offerings), as well as transition costs, must mirror those for direct access. PGE and PacifiCorp may propose VRET terms and conditions that differ from current direct access provisions but must proposed changes to their respective direct access programs to match those changes.

7. The regulated utility may own a VRET resource, but may not include any VRET resource in its general rate base. It may recover a return on and return of its investment in the VRET resource from the VRET customer; however, the utility must share some of the return on with other utility customers for ratepayer-funded assets used to assist the VRET offering.

8. All direct and indirect costs and risks are borne by the VRET customers, shareholders of the utility, or third-party developers and suppliers with provisions allowing independent review and verification by the Commission Staff of all utility costs. Costs include but are not limited to ancillary services and stranded costs of the existing cost of service rate based system.

9. All VRET offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.[3]

The Commission ultimately decided to defer its decision as to whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide VRETs to nonresidential customers.[4] Instead, the Commission indicated it would make this determination with the benefit of a program designed by an interested electric utility.[5]

On April 13, 2018, PGE filed to reopen docket UM 1690 with an application for a VRET that included more specific design elements by which the Commission could determine the reasonableness and public interest of PGE’s proposed VRET. On May 24, 2018, docket UM 1953 was opened and the Commission

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[3] Order 15-405 at 1-2.
[4] *Id.*
[5] *Id.*

ultimately approved PGE's Green Energy Affinity Rider through Order No. 19-075. The Commission's Order directed parties to consider more complex policy issues in a second Phase. Under Phase I of the program, PGE was permitted to offer up to 300 MW of new nameplate resources through PPAs under this program.

On May 31, 2019, PGE opened customer enrollment for Phase 1 of its GEAR. PGE's first offering was largely a success with 160 MW of demand expressing interest and ultimately subscribing to the program in a matter of minutes. Since that time, two customers have expressed interest and are pursuing enrollment using the remaining 140 MW of cap space under the Phase 1 program. The cap was split into two programs: 100 MW of PGE procured resources (PGE Supplied Option, PSO), and 200 MW of customer procured resources (Customer Supply Option, CSO).

PGE filed opening testimony in Phase II of this docket on June 14, 2019, related to both the VRET conditions, generally, and proposed changes to its GEAR program. Staff and Intervenors filed opening testimony on July 26, 2019. Following a schedule suspension to attempt to settle, PGE filed reply testimony on October 17, 2019. The procedural schedule for Phase II was again suspended following the Commission's direction at the October 22, 2019, public meeting, to allow parties to better define the differences in procurement and application of the cap for the CSO and PSO programs. PGE filed a second reply testimony on April 15, 2020.

ISSUE 1. VRET CONDITIONS

Q. Does Staff have any overarching comments regarding the Commission's reconsideration of the nine VRET conditions?

A. Yes. As Staff noted in opening testimony of Phase II of this docket, PGE has proposed some changes that may seem reasonable when considered in relation to PGE's GEAR program. However, the nine conditions apply to any and all future VRET offerings from any utility. Staff does not find it reasonable to amend the conditions based on the specific circumstances of PGE's GEAR when future changes to the GEAR or another future VRET may not follow the same structure.

Renewable Northwest (RNW) also raised an issue regarding the Company's proposal to change the nine conditions to guidelines. Neither the Company nor RNW has explicitly explained how the change in vernacular would apply to Commission oversight or Company compliance, however Staff does not support this change. The Commission was clear when setting up the conditions that they should be more than mere suggestions to VRET structure; to the contrary, it is based on these guidelines that the Commission found that Oregon utilities offering a VRET could be in the public interest. Staff's goal in proposing changes to the conditions is to set up a framework for any VRET to ensure that the construct continues to be in the public interest. Staff is concerned that changing the conditions to guidelines may cause them to lose some of their impact. This calls into question the necessity to adhere to the conditions, which in turn calls into question the VRET's ability to meet the public interest mandate.

Condition 1

Q. Please restate the current Condition 1.

A. Renewable Portfolio Standard (RPS) definitions that must apply to voluntary renewable energy products are for resource type, location, and bundled Renewable Energy Certificates (RECs).

Q. What are parties position regarding Condition 1?

A. PGE, RNW, PacifiCorp, and NIPPC all support that the original condition be unchanged. CUB suggests a modification to allow battery storage to be included in VRET applications. RNW also proposes the inclusion of battery storage in VRETs but does not do so in reference to Condition 1.

Q. What is Staff's response to parties' positions?

A. Staff believes the inclusion of battery storage in conjunction with a renewable resource, similar to PGE's Wheatridge Renewable Energy Facility (Wheatridge), may make sense for future VRET resources, particularly as battery storage costs decline and mixed resource facilities like Wheatridge become more common and economical. Staff sees VRET programs as means for interested customers to reduce their carbon footprint, and battery storage can be a potentially valuable part of this solution. It also reduces the risk that VRET procurements will result in a materially different resource portfolio mix than the traditional IRP process would otherwise select. This is because it includes one more viable solution in VRET procurement that is otherwise only considered in the IRP. The IRP may still select a materially different optimal resource solution based on need because it looks at a wider variety of potential solutions and utilizes battery storage as a potential stand-alone solution, but its inclusion in VRET would reduce this likelihood incrementally. Battery storage does raise several additional concerns for Staff, however, regarding the proper way to recompense the participants for the added benefit. Staff maintains that the VRET should not be used primarily as a means to reduce overall power costs, and fears that the inclusion of battery storage in a VRET may allow for more direct competition with Direct Access (DA) offerings. As such, Staff supports the inclusion of battery storage in Condition 1, but recommends that any future procurement of VRET resources with battery storage be required to receive Commission approval for credit calculation prior to implementation.

Q. What is Staff's proposed language for Condition 1?

A. *Renewable portfolio standard (RPS) definitions that must apply to voluntary renewable energy products are for resource type, location, and bundled renewable energy certificates (RECs). Non-carbon emitting energy storage resources may be included but only in conjunction with RPS compliant resources.*

<u>Condition 2</u>

Q. Please restate the current Condition 2.

A. VRET options should only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants, unless the participants consent to RECs being retired by the utility or the developer.

Q. What are parties' positions regarding Condition 2?

A. PGE, RNW, PacifiCorp, Staff, and CUB all support that the removal of the "gifting" option in Condition 2. CUB further suggests a modification to reduce the utility's RPS requirements by the load being served by the VRET resource. NIPPC opposes any changes to the original nine conditions.

Q. What is Staff's response to parties' positions?

A. Staff maintains its original position that "gifting" of REC's back to the utility adds potential confusion and runs counter to the additionality goal of VRETs. Staff believes CUB's concern may have merit if the load subscribed to VRET programs were to increase substantially; however under the current size of VRET resources, CUB's modification only serves to reduce additionality of the program and limit a customer's ability to have a meaningful impact on the amount of carbon consumed in the state. Staff recommends that the Commission follow Staff's guidance regarding the review of VRETs in the IRP to identify if and when VRET load is have a potential impact on the utility's ability to meet RPS compliance.

Q. What is Staff's recommended language for Condition 2?

A. *Voluntary renewable energy options include only bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants.*

Condition 3

Q. Please restate the current Condition 3.

A. The year in which a VRET eligible renewable resource became operational should be no earlier than 2015.

Q. What are parties' positions regarding Condition 3?

A. PGE, CUB, RNW, PacifiCorp, and Staff recommend that Condition 3 be changed to ensure additionality of VRET procurement moving forward. The proposal changes the static "2015" date to "one year prior to program enrollment." NIPPC opposes any changes to the original nine conditions.

Q. What is Staff's response to parties' positions?

A. Staff maintains its original position that the Condition should be made more dynamic and applicable to VRET programs moving forward. Utilizing a static date will become less and less impactful in the future. Staff believes that the term "program enrollment" listed below should be defined as when the customer signs a binding agreement to participate in the program.

Q. What is Staff's recommended language for Condition 3?

A. *The year that a voluntary renewable energy program eligible resource became operational should be no earlier than one year prior to program enrollment.*

Condition 4

Q. Please restate current Condition 4.

A. The VRET program size is limited to 300 aMW for PGE and 175 aMW for PacifiCorp.

Q. What are parties' positions regarding Condition 4?

A. PGE and RNW support a change to Condition 4 from 300 aMW to 500 MW. Staff and CUB opposed raising the cap until empirical evidence from Phase I of the GEAR was available.

Q. What is Staff's response to parties' positions?

A. Staff supports the change from average megawatts to megawatts in order to provide a more direct limiting factor on the procurement process. As PGE notes, the capacity factor of renewable resources can vary based on location, type, and performance. Unlike Direct Access caps, which are based on customer load, VRET programs are procured in tranches for specific resources. As such, the cap is clearer when expressed as MWs as opposed to aMWs. Staff will address its thoughts concerning raising the cap for the GEAR in a subsequent section of testimony.

Q. What is Staff's recommended language for Condition 4?

A. *The VRET program size is limited to 300 MW for PGE and 175 MW for PacifiCorp.*

<u>**Condition 5**</u>

Q. Please restate current Condition 5.

A. VRET product design should be sufficiently differentiated from existing direct access programs.

Q. What are parties' positions regarding Condition 5?

A. PGE and PacifiCorp propose the removal of Condition 5. CUB, NIPPC, and Staff oppose changes to Condition 5. RNW states that removal of Condition 5 may be reasonable if the utility offers regular updates to the Commission regarding the relative success of the VRET and DA to ensure both programs remain competitive.

Q. What is Staff's response to parties' positions?

A. Staff continues to believe that Condition 5 is reasonable as currently written. As Staff noted earlier, the Conditions need to be applicable to any and all future VRET programs. PGE notes that an ESS could develop a product that would mimic PGE's GEAR thus prohibiting PGE from continuing to offer the product. Staff notes that an ESS would not be able to offer any product that allows the customer to continue to receive service from the incumbent utility, at rates that cannot go below standard COS rates, with a fixed crediting methodology based on IRP valuation methods. Staff, the Commission, and parties have worked to ensure PGE's GEAR is sufficiently differentiated from DA, but in order to ensure that any future program is subject to the same consideration, Condition 5 must be maintained. PGE and PacifiCorp argue that as long as the utility ensures that the VRET does not result in cost shifting, then there is no concern for a VRET's impact on the competitive retail market. As Staff will discuss further in briefing, the Commission has an obligation to ensure that it does not create barriers to the competitive marketplace. Therefore, the Commission's considerations must go beyond simple cost-shifting to non-participating cost-of-service customers.

Q. Please provide an example of your concerns regarding the elimination of Condition 5.

A. As an example, PGE's first GEAR phase with some changes that theoretically do not result in any cost shifts:

- Fixed credit methodology with no ceiling (allowed net bill savings)
- No program cap
- CSO option where PGE can perform procurement for customer
- Utility ownership of VRET resources allowed as PGE proposes
- All other aspects of GEAR maintained

Based on the results of PGE's first GEAR where the ceiling price was reached based on IRP credit methodology and PPA price, it is not unreasonable to believe that a VRET with this setup would allow for cost savings beyond COS rates. Theoretically, this setup should not result in cost shifting and would not conflict with HB 4126; however, it would raise concerns about the impact on the competitive marketplace. Although, the accuracy of the valuation methodology is subject to forecast error, it is inherently the same risk as any long-term PPA. Program caps, CSO procurement, utility ownership (which ensures no cost-shifting as PGE proposes) do not violate cost shifting principles; however, the result is a program where any small customer could sign-up for guaranteed bill savings regardless of its desire to reduce greenhouse gas emissions. Any large customer could approach PGE and ask it to procure a resource that would meet particular energy price goals. In addition, PGE could go out, build resources for both the smaller customers and larger customers, without adhering to the competitive bidding rules (CBRs were waived for Phase I), and earn rates of return on the VRET resources and all other investment from the program participants. ESSes would be harmed because the VRET would no longer just appeal to those looking to have a meaningful impact on carbon emissions, but instead on customers that simply want the opportunity to save money on their bills—a scenario that is typically within the purview of direct access.[6] The competitive marketplace would be impacted because PGE would be able to appeal to all of the demand for service from its own resources, thereby chilling competition. This may be an unlikely example, but it is meant to illustrate the point that there are many other concerns regarding protection of the competitive retail market than cost shifting alone. A VRET must not allow COS customers to subsidize a product that would otherwise be subject to the competitive marketplace. Even if you could exactly match a Direct Access offering to PGE's GEAR, incumbent utilities generally benefit from the established customer relationship and there are fewer administrative and financial constraints (such as notice windows, transition charges, etc.). When Staff noted that cost-shifting was the only way a VRET could be a "better deal" than direct

[6] This also raises issues of equity to customers that are not eligible to participate in a VRET program, such as residential customers, who must pay a premium relative to COS rates for green products.

access in its UM 1690 Staff Report, it was in reference to the benefits of the VRET, not the potential impacts to the competitive marketplace.[7] Without proper differentiation and forethought into program design, VRETs could harm the competitive market based solely on the fact that they are offered by the incumbent utility with no need to require the customer to venture out on their own.

Q. What is Staff's recommended language for Condition 5?

A. *VRET product design should be sufficiently differentiated from existing direct access programs.*

<u>Condition 6</u>

Q. Please restate current Condition 6.

A. VRET terms and conditions (including the timing and frequency of VRET offerings), as well as transition costs, must mirror those for direct access. PGE and PacifiCorp may propose VRET terms and conditions that differ from current direct access provisions but must proposed changes to their respective direct access programs to match those changes.

Q. What are parties' positions on Condition 6?

A. PGE, CUB, and PacifiCorp propose the removal of Condition 6. NIPPC advocates for Condition 6 to be maintained as-is. RNW states that an amendment toward parity and not mirroring may be warranted. All other intervenors took no position on the matter. Staff proposed an amendment to Condition 6, along similar lines as RNW. Staff's thought was that one-to-one

[7] PGE/500, Sims-Tinker/24, line 7.

mirroring may not be the most reasonable approach in all aspects, but ensuring fairness between VRET and Direct Access programs should continue to be a condition to VRET programs.

Q. Why do some parties propose the removal of Condition 6?

A. CUB notes that Conditions 5 and 6 are potentially somewhat contradictory. Condition 5 states that VRET and Direct Access programs must be different, whereas Condition 6 can be interpreted to mean they have to be the same. PacifiCorp relies on similar arguments although the Company did recommend removal of Condition 5 thus alleviating the apparent contradiction. Nevertheless, PacifiCorp notes that Direct Access programs allow a customer to opt-out of retail service while a VRET customer remains a cost-of-service customer. Thus, mirroring is not realistic due to the inherent difference in the programs. PGE argues that mirroring of program offerings would hinder competition and create "a more homogenous marketplace with less attractive options for customers."[8]

Q. Why does NIPPC propose Condition 6 be maintained?

A. NIPPC summarily notes that there have been no significant changes in law or fact since the Commission issued its order adopting the nine conditions. NIPPC further notes that the Commission is charged with the protection and development of the competitive retail market and Condition 6 is paramount to this charge. The Commission only found VRETs to be in the public interest if all nine of the conditions were met, and even then, Commission Chair Ackerman

[8] PGE/500, Sims – Tinker/28, line 18 – 19.

dissented. Chair Ackerman's position was that VRET's were not in the public interest even when all nine conditions were met.

Q. Has any parties' testimony made Staff reconsider its position?

A. No, not substantively. Staff can appreciate the perspective that each party has provided, but continues to believe that a condition which ensures that both DA and VRET programs can coexist and results in fair treatment for both is warranted. Staff further notes that these conditions apply to any future VRET as well as PGE's currently approved and proposed GEAR. Some of PGE's and Parties' proposed changes to the conditions are only based on the circumstances surrounding the current program under consideration. However, Staff does not believe this is an appropriate approach, and thus seeks to implement conditions which apply more broadly.

Q. Did PGE offer any response to Staff's proposed amendment?

A. Yes. PGE noted an appreciation for an emphasis on fairness as opposed to mirroring; however, PGE did maintain some reticence regarding the subjective nature of Staff's proposed amendment. PGE noted that should the Commission be inclined to modify Condition 6, it would propose the follow verbiage:

> *If a utility seeks to offer a voluntary renewable energy product outside of or in lieu of cost-of service, the following guideline applies:* Such VRET terms and conditions must fairly account for differences from Direct Access programs. The Utility may propose terms and conditions that differ from current Direct Access provisions, but must provide

evidentiary support for those differences and must consider changes to their direct access programs to match such VRET terms and conditions, as appropriate.[9]

PGE's proposal would maintain Staff's language but include the italicized conditioner.

Q. Does Staff agree with PGE's proposal?

A. No. Whether or not a VRET program is outside of COS has no bearing on its potential implications for DA programs. Staff notes that it can be inferred from PacifiCorp's testimony that all VRET products are cost-of-service products.[10] Although Staff does not necessarily agree with that assertion, Staff does believe that PGE's addition to Staff's language would severely limit the applicability of Condition 6 to the detriment of the competitive marketplace.

Q. How would a VRET program designed as a COS rider unfairly compete with Direct Access?

A. Staff argued in the first phase of the docket that a fixed credit methodology which allows the participant to realize energy prices below COS rates would present an unfair advantage for the VRET over DA programs. The VRET presented a program with more cap space than is currently available under PGE's Long-term Direct Access (LTDA) program, is open to smaller customers, allows the customer to maintain its relationship with the utility, offers price assurance, avoids transition charges, and allows the customer to

[9] PGE/600, Sim-Tinker/22, lines 8-14.
[10] PAC/100, Lockey/5 line 6-7.

access lower power prices available in the wholesale market. With PGE's proposed addition to Staff's language, there is no condition which would require the Company to account for this concern.

Q. Why does Staff believe Condition 6 is important?

A. As noted in earlier rounds of Staff's testimony, the interaction between VRET programs and DA programs is a major concern regarding the determination that a VRET is in the public interest. The Oregon legislature has made it abundantly clear that the protection of competitive retail energy markets is central to the Commission's goals and all consumer choice options outside of standard COS product offerings.

Condition 5 requires that VRET and DA programs are sufficiently differentiated, or in other words that they not directly compete with each other for the same customers. It ensures that the VRET is not simply a more favorable replacement for DA. In talking to customers who have enrolled in PGE's first phase or are interested in pursuing further VRET programs, Staff has found that there is a unique space for VRET offerings to meet customer's needs that DA programs are not able to meet. In general, Staff found that these customers are more environmentally focused in their energy related goals. They are hesitant to move outside of PGE's service because they have a level of trust with the utility that they value. They are less concerned with the economic impact of their energy choice than they are concerned with the environmental impact. They would like to meet their climate goals without a large economic impact to their power bill, but it is not their top priority. DA customers, on the other hand, seem to value the freedom and choice provided by DA. They can pursue their individual economic and environmental goals with fewer restrictions at the cost of venturing out beyond the ‘safe harbor’ the incumbent utility presents. Staff believes that the differentiation noted in Condition 5 is targeted at ensuring these two somewhat competing programs are designed to meet these different types of customers or appeal to different customer preferences.

Condition 6 on the other hand, ensures that one program does not have an unfair advantage over the other. A VRET could be designed with certain aspects which would appeal to potential DA customers more than DA programs currently can, as noted in Staff’s example for Condition 5. If a customer could be afforded the same freedom and access to the cheapest available power on the market without having to “leave the nest,” it could have a significant impact on the competitive retail market. Likewise, if VRET programs are so restrictive and cost prohibitive that no customer finds them appealing, it forces customers to either venture out on their own for green products, or settle or the status quo in terms of environmental attributes of their energy supply. This is why Staff believes that both Conditions 5 and Staff’s amended Condition 6 are necessary. Staff believes that the original Condition 6, which relies on mirroring, assumes that sameness equates to fairness between the VRET and DA. Staff is concerned that this approach is at the expense of customer preferences, without a demonstrated benefit. Staff’s proposed language ensures that while the two programs will be differentiated under Condition 5, those differences are inappropriately favoring one program to the detriment of the other.

Q. Why does Staff believe Condition 6 has been particularly difficult to agree upon?

A. Condition 6 has implications not only for the GEAR and any future VRET, but for Direct Access programs as well. With UM 2024, the investigation into long-term DA programs, currently underway, parties realize that the ultimate decision on the 'mirroring condition' will have direct impacts in UM 2024. If the Commission upholds the mirroring standard, then changes to DA would likely follow. If the Commission removes Condition 6, then the interaction between the GEAR and DA would likely become moot. Staff believes that the appropriate course of action is to set a principle that ensures this interaction between the two programs is reasonable and fair, but does not require the rote one-to-one mirroring currently in place.

Q. What is Staff's recommended language for Condition 6?

A. Staff supports the its original proposal for Condition 6:

VRET terms and conditions must fairly account for differences from Direct Access programs. The Utility may propose terms and conditions that differ from current Direct Access provisions, but must provide evidentiary support for those differences and must consider changes to their direct access programs to match such VRET terms and conditions, as appropriate.

Staff also supports this alternative language:

Voluntary renewable energy product offering terms and conditions (including the timing and frequency of offerings), as well as transition costs must match terms and conditions of direct access to the extent practicable. The Utility may propose terms and conditions that differ from Direct Access provisions, but must demonstrate that the different terms and conditions are reasonable, in the public interest, and consistent with the Commission's legal authority. The utility maintains the burden of proof with regard to the difference between direct access offering terms and conditions and proposed VRET offering terms and conditions.

Condition 7

Q. Please restate current Condition 7.

A. The regulated utility may own a VRET resource, but may not include any VRET resource in its general rate base. It may recover a return on and return of its investment in the VRET resource from the VRET customer; however, the utility must share some of the return on with other utility customers for ratepayer-funded assets used to assist the VRET offering.

Q. What are parties' positions regarding Condition 7?

A. PGE, PacifiCorp and Staff support a modification to Condition 7. The proposed language would read:

The regulated utility may own a voluntary renewable energy resource, and when it does, it must continue to ensure there is no cost shifting to non-participants.

CUB expressed some concerns regarding the change but agrees that the requirement to share some of its return on investment may not be needed in the context when a green tariff is a COS rider. Other parties expressed concern or oppose the prospect of utility ownership.

Q. What is Staff's response to parties' positions?

A. Staff believes that CUB's comment regarding the return on investment when a VRET is a COS rider is a bit misguided in that it again applies specifically to PGE's GEAR. The cost-shifting principle considers the appropriate compensation to COS customers, regardless of program design. Staff does, however, believe that some modification to Condition 7 is appropriate after reviewing other parties' testimony and considering the condition further.

Q. What is Staff's concern with PGE's proposed language?

A. Staff's report in UM 1690, which largely shaped the nine conditions, notes a concern for the impact of utility ownership on the retail market. Conditions 5 and 6 ensure that the VRET and DA can coexist as they relate to value propositions to potential customers, but do not consider what impact utility ownership may have on the retail market. If a utility were to offer a utility owned resource in a VRET, the impact to other suppliers needs to be considered. Staff aims to ensure that utility ownership does not result in crowding out of suppliers, particularly since there are potentially some customers who would otherwise choose direct access. Consider the scenario where a utility owned resource is always the least cost, least risk option. It would reasonably be selected in every future VRET tranche. This may provide a benefit to participants in the short-term, but as fewer and fewer other viable projects are selected, the number of participants in any RFP may fall. This would result in less competition for not only the VRET, but also DA and COS resource procurement, particularly if some customers who would have otherwise elected to pursue DA instead sign-up for a VRET. Condition 7 needs to ensure that utility ownership does not create a barrier to the competitiveness of the retail market. This involves reviewing the longer-run impacts of utility ownership and the relative size of VRET offerings compared to energy demand in the region. It is not to say that any utility project that is selected as a VRET resource is inherently counter to competition, but the Commission must consider whether or not the utility's size, access to cheaper capital, and regulated utility status is resulting in an unfair competitive advantage. PGE's proposal does not take this concern into consideration and as such is insufficient for a condition.

Q. What is Staff's recommended language for Condition 7?

A. *The regulated utility may own a voluntary renewable energy resource. When it does, it must continue to ensure there is no cost shifting to non-participants and the offering does not create a barrier to the competitive retail market.*

<u>Condition 8</u>

Q. Please restate current Condition 8.

A. All direct and indirect costs and risks are borne by the VRET customers, shareholders of the utility, or third-party developers and suppliers with provisions allowing independent review and verification by the Commission Staff of all utility costs. Costs include but are not limited to ancillary services and stranded costs of the existing cost of service rate based system.

Q. What are parties' positions regarding Condition 8?

A. PGE, CUB, RNW, and PacifiCorp support a modification to Condition 8 to:

All direct and indirect costs and risks are borne by the participating voluntary renewable energy customers, shareholders of the utility or third-party developers and suppliers with provisions allowing independent review and verifications by Commission Staff of all utility costs.

This amendment would remove "Costs include but are not limited to ancillary services and stranded costs of the existing cost of service rate-based system." PGE notes that this streamlines the condition and removes an apparent redundancy. Staff and NIPPC opposed this change.

Q. What is Staff's response to parties' positions?

A. Staff continues to believe that the inclusion of the final sentence of the original Condition 8 is appropriate. Staff reiterates that this condition is not solely meant to apply to PGE's GEAR and its position as a COS rider should have no material impact on the implication for the conditions. Staff does not see any material benefit in the removal of the sentence, and believes the change only serves to reduce clarify to any reader who may not be intimately familiar with cost shifting concerns. Staff has not seen any persuasive evidence on the record as to why the change should be made. One change that Staff would support in regards to potential cost shifting of

VRET programs relates to IRP planning. One of the major long-term concerns for VRETs as they potentially grow in size and popularity in the state is in regards to how they impact the utility's least cost/least risk planning. Staff has noted previously in UM 1953 that regardless of what the utility puts in place to ensure there is no cost shifting, the mere fact that procurement is occurring outside of the IRP process for load being served by the utility, it will have an impact on the preferred portfolio of the Company in the IRP. There are no other conditions that even potentially address this major concern. Staff will address how PGE's GEAR should be considered during the Company's IRP, but again these conditions are not meant to specifically address the GEAR and they do not currently consider this issue. Staff proposes that the language in the second sentence of Condition 8 be altered so that it would apply to long-term planning.

Q. What is Staff's proposed language for Condition 8?

A. *All direct and indirect costs and risks are borne by the participating voluntary renewable energy customers, shareholders of the utility or third-party developers and suppliers with provisions allowing independent review and verifications by Commission Staff of all utility costs. Cost include but are not limited to ancillary services and costs of the existing* ***and future*** *cost of service rate-based system.*

<u>Condition 9</u>

Q. Please restate current Condition 9.

A. All VRET offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.

Q. What are parties' positions regarding Condition 9?

A. All parties agree that Condition 9 should be maintained as currently approved.

Q. What is Staff's proposed language for Condition 9?

A. *All voluntary renewable offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.*

Q. Does Staff have any further comments regarding the Conditions and PGE's GEAR?

A. Yes. It pertains specifically to Condition 6. PGE is the only utility that currently has a VRET. Any change to the methodology of PGE's GEAR or any application for the approval of a new VRET must consider compliance with approved conditions. This includes the interaction between the VRET proposal and DA. Differences may be warranted, but approval of those differences should be based on testimony that discusses why the differences are appropriate or not. The testimony should either provide a substantive reason for the difference or explain how the utility is going to implement the proposed change to DA programs. This is not to imply that any change to the GEAR need be made in a contested case; the utility is able to and has included testimony in support of tariff changes that the Commission considered in the public meeting process.

For PGE's GEAR, Staff believes that should the Commission adopt Staff's language or otherwise maintain or amend Condition 6, the proper course of action would be to direct the Utility to address differences in the VRET and DA in UM 2024. One example is that of capacity credits. In the GEAR, customers are credited for capacity during times the utility is short, however currently in PGE's LTDA program, DA customers are not credited for any capacity they may free up by leaving the system. Whether or not this difference is warranted or reasonable can be discussed in UM 2024.

ISSUE 2. ENERGY AND CAPACITY CREDITS

Q. Please provide a background for this issue.

A. In its opening testimony, PGE proposed the continued use of its currently approved credit methodology from Phase I. This utilizes the IRP methodology to value energy and the RECAP model to calculate capacity value during times of resource deficiency. Staff supports this methodology although noted some concerns regarding the risk imposed on COS customers inherent in assuming a 15 or 20-year fixed price forecast. Staff agrees with PGE, however, that this risk is the same for any long-term PPA contract for COS customers. CUB, Walmart, and RNW prefer a floating credit methodology, that would allow VRET participants to achieve net bill savings compared to COS rates. CUB proposes the use of Staff's preferred floating credit methodology, which is based on the actual power cost impact for COS customers using the MONET model. CUB's argument is that this approach would reduce the market price risk for COS customers. RNW believes that a floating credit may spur more customers to enroll in the program if a reduction in energy costs were possible. Walmart proposes the use of a marginal cost based credit similar to AWEC's proposal from the first Phase of UM 1953.

Q. What is Staff's response to parties' positions?

A. Staff continues to find that a fixed credit, utilizing the IRP methodology is the optimal solution. Staff prefers this method for a number of reasons. First, the methodology is directly tied to PGE's need as assessed in the IRP. This reduces the potential cost shifts and makes the program more in line with the traditional planning process for COS customers. Second, a fixed credit provides participants with price assurance, which PGE noted was valued by customers. Last, because the credit cannot result in net bill savings, it creates a larger difference between VRET and DA offerings, reducing concerns that the VRET could be considered a barrier to the competitive retail market. Staff agrees with PGE that COS customers should be indifferent between a fixed and floating credit, as both require COS customers to assume risk and both are based on the available information at the time. Staff continues to support the consideration of floating credits for the CSO option, utilizing the methodology proposed by CUB in this phase as described above. As noted previously by Staff, this is the most direct way to ensure no cost shifting occurs, and is based on the way that power costs are actually set. Using marginal cost studies to value energy and capacity lacks the direct connection to actual power cost recovery. CUB further argues that the likelihood of net bill savings from a floating credit are unlikely, however Staff would caution against this belief as evidenced by the resulting credits from the first phase of this program.

Q. CUB recommends a change in the capacity valuation methodology, does Staff support this change?

A. CUB proposes to use a technology-neutral proxy to value capacity during resource insufficiency times, as opposed to a single cycle combustion turbine. Staff supports this specific change in methodology as it better reflects the actual capacity cost that is avoided due to the VRET program. PGE's preferred portfolio is largely based on the least cost means to meet customer needs for energy and reliability. Thus, the avoided cost associated with procurement in the VRET is the least cost IRP solution. This may be a single cycle combustion turbine, but may likely not be.

ISSUE 3. CAP SIZE

Q. Please provide a background for this issue.

A. PGE is proposing to increase the cap size of the GEAR from 300 MW to 500 MW. In PGE/700, PGE updated its request to effectively remove the distinction between CSO and PSO caps moving forward, allowing either type of customer to enroll up to the cap with no single participant allow to take up more than half. RNW supports PGE proposal while CUB and Staff do not support an increase.

Q. What is Staff's response to parties' testimony?

A. Staff stands by the concerns it raised in opening testimony of this phase. There has been little to no information or experience garnered from the first phase outside of the fact that a fixed credit methodology is desirable by customers. The Commission set the cap as a reasonable risk threshold for COS customers to bear given the known and unknown factors at the time. Without operational experience, the unknown factors remain, and any increase to the cap would further increase those risks. For example, the likelihood that the VRET will materially alter the IRP process increases, because a larger program has larger impacts on resource needs. The likelihood that market price fluctuations will harm COS customers goes up, because a higher percentage of COS power would be provided by a fixed price PPA, all else equal. In addition, the potential for unforeseen cost shifting goes up, because we have not been able to empirically prove that the design is without fault. Staff understands PGE's desire to meet customers' goals, particularly in a timely manner given some customers current climate goals. However, optionality for a certain subset of customers should not come at the expense of COS customers. Non-residential customers have the option to participate in direct access programs to meet environmental and economic requirements, whereas COS do not. A participation cap, for the time being, strikes an appropriate balance between these two competing goals: limiting the risk for COS customers and allowing some customers to meet their climate goals.

Q. Does Staff have any further recommendations regarding cap size?

A. Yes. If the Commission is inclined to increase the cap to some extent in order to allow PGE to meet customer demand, Staff recommends that the Commission set the cap at the amount it believes reasonable for the PSO portion of the program. As PGE noted in reply testimony, the CSO program is slower moving, likely because the process is more involved for a single customer to undertake and procurement is more foreign than to PGE. The use of a single cap as proposed by PGE would result in PGE filling up the cap with PSO customers as quickly as demand allowed. The inclusion of CSO in the cap would likely not result in any meaningful participation by these customers other than to enroll in the PSO program if the economics were desirable. Staff believes that the structural distinction, as agreed to by parties, is a meaningful and warranted one. Providing large customers with the freedom of choice inherently reduces the risk that PGE's GEAR program is a barrier to the competitive retail market for customers located within its service territory. Staff's proposal would be to have the Commission set the cap for the PSO offering and allow CSO customers to apply for program participation on a case-by-case basis. This would maintain the distinction between the two programs and allow the Commission to only consider increases in the CSO cap based on actual customer demand. This may limit the amount of risk COS customers are required to bear as a result of increases to the VRET program.

ISSUE 4. RISK ADJUSTMENT FEE

Q. Please provide a background for this issue.

A. PGE proposes four total risk categories to be included in its risk adjustment fee. The first is undersubscription, which PGE notes in PGE/500 was discussed and ultimately approved in Phase I of this docket.[11] This risk involves misalignments between term length of customer subscription and PPA length. The second is customer load variability risk, which results when a customer uses less (or more) energy than subscribed for. The third is variable resource risk, which is occurs when the renewable resource produces above or below expected levels. The final is PPA risk, which is the general risk of deal with a third-party to develop, construct, and operate a resource.

In response, Staff and RNW requested further detail regarding the methodology for quantifying these risks. Staff further noted that the PPA risk effectively resulted in a return on investment for PPA's, one that could be reasonable applied to any PPA for COS customers. PacifiCorp expressed support for the appropriate quantification and compensation of risk to shareholders.

In reply testimony, PGE agreed with Staff that the PPA risk could be applied to any COS PPA and noted they recommend exploring a risk adjustment COS PPAs in another docket. Further PGE stated that Staff's "return on investment" correlation was accurate. PGE also provided a range of "no

[11] PGE/500, Sims-Tinker/13, line 14 to 16.

more than 10%" for comprehensive program- and PPA-based risks as well as providing further detail regarding the source of the risks.

Q. What is Staff's response?

A. As PGE has noted, if equally applicable to any and all COS PPAs, the consideration for this risk has implications far beyond the VRET program. Staff recommends that the Commission not approve this portion of the risk adjustment fee and instead direct PGE to raise this concern in a more generic docket like a general rate case, which would apply to any future PPA for COS or VRET customers. This is not the proper venue to consider such a drastic shift in the traditional PPA pricing process.

This leaves Staff to wonder, what the appropriate risk adjustment fee may be. PGE has not provided any quantification of each specific risk, but based on PGE's testimony, Staff believes some inferences can be made. PGE notes in reply testimony that the undersubscription risk as approved by the Commission in Phase I was estimated to be in the range of 1 to 5 percent. The additional three risks raised the overall "comprehensive program and PPA-based risks" to a maximum of 10 percent. This means that customer variability, variable resource, and PPA risks account for between nine and five percent. Assuming that these three risks are approximately equal in size, this means that the appropriate risk percentage would be between 7 and 8.3 percent when not including PPA risk. Obviously, this is an imprecise approximation, but it illustrates the vague methodology of the Company's proposal. Staff continues to request that the Company provide a more concrete means of quantifying these risks. Given the expected cost to shareholders of each particular risk and the likelihood of each risk occurring, the utility should at least be able to provide a more transparent means of estimation. Staff continues to maintain that these risks (other than PPA risk) may be reasonable if quantified in a sufficient manner, but PGE's proposal in this case is unsupported by any evidentiary basis.

Q. Does Staff have any other concerns?

A. Yes. Staff is concerned that apart from the imprecise and apparent ad hoc nature of PGE's methodology thus far, PGE has failed to consider or account for potential changes in the risk profile for shareholders which are specific to the circumstances surrounding each tranche. Staff assumes that in the event of excess energy above subscribed amounts, shareholders would be compensated at the same fixed credit as subscribers. To continue to charge COS customers the PPA price would then result in cost-shifting concerns and violate the terms of the VRET as COS customers would enjoy free energy to the detriment of PGE shareholders. For example, consider a CSO customer who enrolls for a 100 MW resource for 20 years, and in year five they shut down. It would not be financially viable to provide a free resource for fifteen years. This means that the risk to shareholders for excess energy is contingent upon the fixed credit amount and PPA price. In the case of PGE's first phase, these numbers are the same, meaning they offset and PGE is only left with its own administrative costs for shareholders to pay. The PPA price is the same as the VRET credit, the resource's estimated output is included in PGE's annual power cost like any other PPA, so effectively the VRET PPA functions the exact same as a standard PPA and there is no additional risk for shareholders. This applies to the energy portion of all the three remaining risks PGE has identified but it is not considered when setting the risk adjustment fee. Staff believes that the total identified risk by PGE when the PPA price is the same as the credit methodology is the cost of purchasing or selling RECs from resource variability risk. Further, PGE notes concerning the potentiality of resource under-generation that "PGE includes performance guarantees in the PPA to significantly reduce the risk that material under-generation occurs."[12] Further, PGE notes that resource over-generation can be used to bank RECs to help mitigate the risk of future under-generation.

Q. What is Staff's recommendation for this issue?

A. Staff recommends that the Commission deny PGE's inclusion of a generic PPA risk adjustment fee. This should be addressed in a separate, more appropriate docket. Staff further recommends that the Commission require PGE's risk adjustment fee to consider the risks to shareholders based on a more accurate consideration of the circumstances. Staff recommends that the Commission approve the new risks as reasonable but not allow PGE to increase the maximum risk adjustment fee beyond what it already approved in Phase I of the docket until they file a tariff filing with a more appropriate methodology which Staff and the Commission can review.

[12] PGE/600, Sims-Tinker/34, lines 5 and 6.

ISSUE 5. UTILITY OWNERSHIP

Q. Please provide a background for this issue.

A. In the first phase of the GEAR, PGE stated it had no intent to pursue utility ownership of a VRET resource. In the second phase, PGE indicated that it was not currently interested in utility ownership but would like the ability to pursue it in the future. PGE followed up its request in reply testimony by stating that it was seeking clarification from the Commission. PGE goes on to note that it believes including a VRET in rate base should be an option, and that current regulatory processes are sufficient to ensure oversight of any potential utility owned GEAR offering.

Q. Did any parties offer thoughts or concerns on this issue?

A. Yes. NIPPC opposes utility ownership. RNW supports it as long as the Competitive Bidding Rules (CBR) apply. CUB noted some concerns particularly with including projects in rate base and recommends "enhanced scrutiny at the Commission," to ensure there is no cost-shifting.[13] In opening testimony, Staff noted that the Company had not made a proposal and reserved judgment until such time that PGE offered more details. Staff is not opposed to utility ownership of a VRET resource, and notes that it is expressly allowed under the previously approved Condition 7.

Q. What is Staff's response to parties' testimony on the matter?

[13] CUB/200, Jenks/16.

A. Staff agrees with RNW that utility ownership makes the procurement process particularly important. Staff also agrees with CUB that additional scrutiny is warranted given the potential for cost-shifting and risks for COS customers.

Q. Has PGE provided a proposal for utility ownership in the GEAR?

A. No. PGE has generally discussed a few high level approaches that may or may not be reasonable depending on the details of the proposal. Staff continues to believe that the ultimate decision on the reasonableness of a utility owned VRET program must occur once all of the details are laid bare. Staff believes that the concerns regarding cost-shifting and the implications for COS customers are diminished should the Company elect to utilize an affiliate or treat the resource as a below-the-line cost. Further, Staff agrees with CUB's concern that the Company's financial health—should it be stuck owning a resource for which it has no customer—could result in significant impacts to COS customers regardless of the protections put in place to eliminate cost-shifting. Staff noted that PGE should provide further details regarding a specific proposal should it desire the Commission to approve a methodology over 10 months ago. PGE has filed two rounds of testimony since then, and to this point has only provided a non-exhaustive list of examples of utility ownership. PGE noted:

> PGE has not decided on a model for ownership that it would seek to implement at a future date. The industry is constantly changing, and the ownership model that makes the most sense for PGE and its

> customers, both non-subscribers and subscriber, will depend on the context at the time it seeks to pursue utility ownership.

Staff believes this is a reasonable approach, and believes that when PGE determines the appropriate ownership model, Staff, parties, and the Commission should review the merits of the proposal at that time.

Q. Does Staff agree with PGE's proposal to utilize the standard regulatory proceedings for review?

A. Not necessarily. Staff believes that a thorough review of the utility ownership proposal is warranted prior to PGE offering it to customers. If the Company would like to discuss the appropriateness of its proposal as an issue during a general rate request or other filing, Staff does not object, so long as this occurs prior to program offering. If PGE is interested in pursuing utility ownership in a VRET prior to a rate case filing, Staff believes that the Company should file an application that includes evidentiary support for the adherence to the nine conditions. Staff sees this the same as any substantive change to the methodological nature of PGE's approved GEAR and would as such be subject to the same considerations and scrutiny as all VRET programs. Staff is concerned that the Company is asking the Commission for some sort of preapproval of utility ownership, and recommends that the Commission clarify the regulatory approval process it expects the Company to follow prior to offering a VRET where utility ownership is an option.

Q. Are there any other considerations Staff would like the Commission to make?

A. Yes. Staff finds the implementation of utility ownership in the CSO of particular concern for several reasons. The first is that the resource would likely be built for and utilized based on the demand of a single customer. This makes CUB's concern regarding a customer's closure or loss of demand more pertinent. It also raises concerns regarding the application of the competitive bidding rules (CBRs) as it relates to the procurement process in the CSO. As Staff will note below, utility ownership is of particular concern for the CBR process. It is unclear, how the Commission could ensure a fair process for the interested customer in a CSO if the utility is including resources which it has an inherent interest in pursuing. Staff does not support both the waiver of the CBR process and utility ownership of a VRET resource. This could effectively turn into a special contract for the CSO customer, with minimal oversight from the Commission. Staff will discuss the interaction of the CBRs and CSO program in testimony below.

ISSUE 6. COMPETITIVE BIDDING RULES

Q. Please provide a background for this issue.

A. PGE is requesting that the CBRs be waived for GEAR related procurement. It states generally that it needs the flexibility and faster decision timelines associated with procurement made outside of traditional RFPs in order to meet customer demand and limit costs being borne by a small number of customers.

Q. How have parties responded?

A. NIPPC believes that the CBRs should apply for all VRET procurement. RNW as noted earlier, believes that the CBRs should apply when the utility is offering utility owned resources in the procurement process. PacifiCorp supports PGEs position that the CBRs should be waived for VRET programs. Staff proposed that the CBR be waived for the second tranche of the GEAR program, but not for VRET programs or future GEAR tranches generally. Further, as Staff noted previously, Staff does not believe the Company has sufficiently laid out a proposal for utility ownership, and as such, would not recommend the waiver of the CBRs for any procurement which included a utility owned project.

Q. Why are parties particularly concerned with application of the CBRs in regard to utility ownership?

A. As noted earlier, the Company would have an inherent bias in the ultimate resource selected for the VRET if it were to include a utility owned resource. The CBRs and RFP process are designed to ensure a fair outcome and process for both customers and suppliers. If the CBRs are amended are waived such that PGE becomes the ultimate decisionmaker for which resource is selected, the utility must be in a position where it is not already inclined towards a particular resource.

Q. Does Staff agree with PGE's concern regarding the cost and timeliness of procurement for VRET offerings?

A. Yes. Staff understands that due to the limited number of customers and the iterative nature of sign-up for a VRET program, full RFPs may unnecessarily limit the number of options available to meet customers' needs. Staff may also be open to a modified process which limits costs and expedites decisions, but believes it must include the following principles:

1. All interested parties are able to provide feedback on the scoring, selection, RFQ criteria, and independent evaluator selection. The Commission sets the criteria at a public meeting.
2. A qualified independent evaluator who reviews the Company's adherence to agreed upon process and proper selection of chosen resources.
3. Ability for interested parties and the Commission to review the scoring and decision-making process.
4. Shareholder assumption of risk for any decisions or outcomes deemed to be outside of the agreed upon standards by the Commission during a second public meeting
5. Review of and potential amendments to this process following procurement.

Q. What is Staff's recommendation for this issue?

A. Staff continues to believe that customer protections in the resource acquisition process are warranted and should be established and adhered to ahead of procurement, with the risk of prudence remaining with the Company. Staff recommends that the Commission adopt a set of principles by which the Company can propose an “RFP light” for review and approval in compliance with the Commission’s order. This process would allow the Company to utilize the amended RFP guidelines for the next GEAR procurement and provide for Commission and party review following the conclusion of the procurement. At that time, the adoption of the standard could be applied to future GEAR procurements should the Commission deem it prudent. If or when PGE offers a more concrete proposal for utility ownership, the Commission can determine if the modified CBR/RFP process is appropriate at that time.

Q. Staff has previously recommended the CBR be waived for Phase II, is this a change in position?

A. Yes. Staff believes the establishment of an amended RFP process will allow the Company to pursue any potential future offerings in a more efficient manner. It will also provide parties and the Commission with familiarity and confidence in the process should the Company pursue utility ownership. Although Staff believes that a one-time waiver of the CBR rules may be reasonable for Phase II, this approach will provide more information and better oversight for this and all future GEAR offerings.

Q. How should the CBRs apply to CSO procurement?

A. As part of the stipulated agreement,[14] parties have agreed to allow PGE to provide assistance in the procurement process should the customer request it. As part of this assistance, Staff recommends that the Company be required to offer the same RFP process it utilizes for the PSO for the CSO customer. The customer would not be under any obligation to utilize the CBR process, but the determination must be made in writing. Further, the ultimate resource selection must reside with the customer and not with PGE. If and when the Company elects to offer a utility owned resource as part of a CSO, the currently approved CBR process for PSO offerings with utility ownership, modified or otherwise, must be used to provide the customer with all the necessary information on which it can then make its selection.

Q. Does Staff have any further thoughts?

A. Yes. Staff notes that this recommendation for a modified RFP process is not intended to be applicable to any VRET or similar product outside of PGE's currently approved GEAR program. This includes any amendments PGE may make to the GEAR, any utility ownership of a GEAR resource, or any other PGE or PacifiCorp voluntary renewable tariff that may be filed in the future.

[14] Commission Order No. 20-036, Attachment A. Regarding the resolution of the queue and program differentiation between CSO and PSO offerings.

ISSUE 7. CUSTOMER SIZE REQUIRMENTS

Q. Please provide a background for this issue.

A. PGE recommends that the CSO be limited to customers larger than 10 MWa to limit the number of CSO applications to manage and limit administrative costs. Walmart argues that the threshold is arbitrary and should be set at 5 MWa to allow for customers with a smaller demand but national footprint to participate. Staff recommends that customers below 10 MWa be allowed to petition the Commission for approval in the CSO on a case-by-case basis. PGE supported Staff's proposal in reply testimony.

Q. What is Staff's response to parties' testimony?

A. Staff continues to believe that consideration of waivers to the 10 MWa threshold on case-by-case basis is the most reasonable means to both limit the administrative costs of the VRET program and allow for customers with unique circumstances to have the opportunity to participate in the program. Staff notes that under its cap proposal CSO expansion would already be handled on a case-by-case basis and the threshold consideration could be reviewed during the same process. This would likely begin in the public meeting process with an option for the Commission to suspend and investigate the matter based on the customer's application and circumstances surrounding the proposal.

ISSUE 8. IRP INTERACTIONS

Q. Please provide a background for this issue.

A. PGE proposes generally to include sensitivity analysis in each IRP to include VRET participation up to the currently approved program cap. It also proposes to include currently subscribed for VRET load in its base case analysis. RNW and Staff generally support this approach.

Q. Does Staff have any further recommendations?

A. Staff had one clarification to make. Staff believes that the Company should provide analysis in every IRP which examines the potential and expected growth of VRET products in the future as well as the total impact of all current VRET products on the utility's IRP planning process. The difference being that the sensitivity analysis should not only consider what is expected to come online in the future based on the currently approved cap, but should also provide the Commission and stakeholders with an idea of the overall total impact VRETs may be having on the planning. This total VRET impact analysis will provide the Commission with information that is useful in deciding upon potential future expansions to the program because the incremental change may be small but the overall total change may be material.

ISSUE 9. TRANSMISSION

Q. Please provide a background for this issue.

A. In opening testimony, PGE proposed that transmission issues in the VRET be considered in a larger transmission focused docket that would apply to all procurement moving forward. Staff and RNW supported this approach. PGE proposed in reply testimony to apply the interim transmission solution as outlined in its 2019 IRP Addendum on August 30, 2019 to VRET procurement.

Q. Does Staff support PGE's use of the IRP Addendum?

A. Yes. Staff believes in the general principal that the VRET transmission issues can be fairly handled in concert with general transmission related procurement issues. Fairness between DA, VRET, and regular COS procurement should be based on equal treatment and requirements for each of these three customer types. The use of the interim transmission solution makes sense in this case as a way to examine the appropriateness of expanded transmission options moving forward.

ISSUE 10. POST PHASE II

Q. What is the Company's proposal for this issue?

A. PGE proposes a streamlined, expedited review process for future cap expansions to this program that would follow a 60-day timeline following a tariff update.

Q. Does Staff have any concerns?

A. Yes. First, Staff is concerned that 60 days may be difficult to complete a sufficient review if the Commission's workload is particularly heavy. Staff believes that in most circumstances, 60 days may be a reasonable time period for Staff to review the filing and analyze the issues in order to make a final recommendation to the Commission at a public meeting. Particularly if the Company is able to provide a complete and in-depth support for its request in its initial filing; however 60 days may not be enough time if significant discovery is required, or if the issues are particularly controversial such that a contested case process may be necessary. Should that be the case, Staff anticipates that 60 days would be enough time to go to a public meeting with a recommendation that the Commission open a contested case proceeding to further investigate the issues. However, Staff prefers a 90 day timeframe, which would better ensure that Staff and interested parties could have time to work through issues in hopes that a final recommendation could be made to the Commission at a subsequent public meeting. Staff believes it is reasonable for the Company to ask that the process be handled in a public meeting, and allow the Company to request a simple "approve or deny" decision by the Commission, but does not believe it is possible to limit the Commission from requesting a more in depth investigation if it deems it to be necessary.

Q. Does this conclude your testimony?

A. Yes.