BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829)	)
BLUE MARMOT VI LLC (UM 1830)	)
BLUE MARMOT VII LLC (UM 1831)	)
BLUE MARMOT VIII LLC (UM 1832)	)
BLUE MARMOT IX LLC (UM 1833)	)
Complainants	)
vs.	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
Defendant	)
Pursuant to ORS 756.500.	)
	)

REPLY TESTIMONY OF

KEEGAN MOYER

ON BEHALF OF THE

BLUE MARMOT V, VI, VII, VIII, AND IX

June 18, 2018

I. INTRODUCTION AND SUMMARY

Q. Please state your name for the record.

A. My name is Keegan Moyer.

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

A. I am a Principal at the firm of Energy Strategies, LLC. Energy Strategies is an independent consulting firm specializing in economic, policy, and power system analysis applicable to energy production, transmission, and consumption.

Q. Have you previously filed testimony in this matter?

A. Yes. On behalf of Blue Marmot V, VI, VII, VIII, and IX (collectively, "Blue Marmots"), I filed a revised version of my Direct Testimony in this docket on December 20, 2017.

Q. What is the purpose of your Reply Testimony?

A. This testimony further supports the Blue Marmots' position that Portland General Electric Company's ("PGE") refusal to counter-sign the Blue Marmot power purchase agreements ("PPAs") and accept the Blue Marmot output is inconsistent with my understanding of how Public Utility Regulatory Policies Act ("PURPA") works. I respond to the transmission study PGE introduced to support its view that transmission constraints restrict its ability to accept the Blue Marmot power. My testimony shows that the study is flawed and that PGE has not reasonably considered the wide range of options it has to accommodate the Blue Marmot output. In taking these positions, my testimony replies to certain arguments in the Response Testimony of PGE submitted on January 12, 2018. I address PGE's "Policy Testimony" submitted by Brent Greene and Geoffrey Moore, its "Energy Imbalance Market ("EIM") Testimony" submitted by Brett Sims, Aaron Rodehorst, and Pam Sporborg, and its "Transmission Testimony" submitted by Frank Afranji, Season Larson, and Matthew Richard. I do not address all issues raised in PGE's testimony, and my silence on any issue should not be construed as supporting PGE's position.

Q. Please summarize your testimony.

A. I revisit and expand on themes from my Direct Testimony. I assert that, despite PGE's arguments, the Blue Marmots have made the required and appropriate transmission arrangements to deliver output to PGE as an off-system qualifying facility ("QF") via a third-party's transmission system. PGE claims that PURPA does not require PGE to accept the Blue Marmots' net output because it would require PGE to sacrifice current transmission capability dedicated to participation in the EIM or impose expensive transmission upgrades.[1] My testimony demonstrates that: 1) PGE has not made a reasonable determination of what, if any, upgrades might be required to accept the Blue Marmot output; and 2) PGE's EIM operations would not be significantly impacted, if it used portions of its transmission capability to accept the Blue Marmot output, including transmission that became available after PGE refused to counter sign the Blue Marmot PPAs.

PGE's testimony seeks to shift its transmission obligations onto the Blue Marmots by taking the position that the Blue Marmots are responsible for arranging transmission on PGE's own system and that PGE alone can select the POD. Requiring the Blue Marmots to do so would be unprecedented and inconsistent with my understanding of PURPA. This opinion is based in part on the fact that I am not aware of either an off-system QF paying for transmission upgrades on the purchasing

[1] PGE/100, Green – Moore/5.

utility's system after it has arranged for delivery to that utility's system or of a utility being allowed to dictate where off-system QFs must deliver their output.

I note that the avoided cost for which the Blue Marmots are eligible does not reflect the cost of transmission upgrades that PGE may contend are needed to deliver the Blue Marmot power on the PGE system. However, the Blue Marmots have done what is needed to lock in the stated avoided cost for its power, and I understand it is now too late now to revise those rates to provide remuneration for transmission upgrades or any other operational costs. Proactive, state-specific implementation of avoided costs and QF policies would be the better way to create a uniform institutional climate for QF development in Oregon, whereas PGE's attempts to reflect its alleged concerns, constraints and costs on a retroactive basis is not.[2]

An important backdrop regarding PGE's position toward QF development is the fact that QF power purchases may avoid the construction of generation on which utility shareholders would have otherwise earned a return, even if ratepayers are indifferent to the purchase of QF power. Given this natural tension, utilities generally have an economic interest in discouraging QF projects.

Whatever PGE's motivation, as a technical matter, I have concluded that PGE has not performed a sufficiently robust and technically accurate inventory of the options it has to manage the Blue Marmots' power. For those options that PGE has considered, I believe that PGE has inflated their costs.

---

[2] ORS 758.515(3) states: It is, therefore, the policy of the State of Oregon to: (a) Increase the marketability of electric energy produced by qualifying facilities located throughout the state for the benefit of Oregon's citizens; and (b) Create a settled and uniform institutional climate for the qualifying facilities in Oregon.

I describe a number of the options I believe PGE can use to manage the Blue Marmot power. These options include use of the power off-system, and transferring onto the PGE system. Though I believe PGE fails to make the case that transmission constraints prohibit it from bringing the Blue Marmot power onto its system, if the Commission finds that the system is constrained, this issue should be addressed prospectively, and not allow PGE to reject the Blue Marmots' offer to sell power under PURPA.

Q. Please outline how your response testimony is organized.

A. I have organized the remainder of this testimony as follows:

SECTION II: Reply to Policy Testimony
SECTION III: Reply to EIM Testimony
SECTION III: Reply to Transmission Testimony
SECTION IV: Summary

Since PGE's Policy Testimony covers both policy issues and the technical issues detailed its Transmission and EIM Testimony, I have attempted to limit my discussion in Section II to issues unique to the Policy Testimony.

II. REPLY TO POLICY TESTIMONY

Q. Please summarize your understanding of PGE's Policy Testimony.

A. The Policy Testimony outlines PGE's interactions with the Blue Marmots, including how it notified the Blue Marmots that it would not accept delivery of their project via the PACW-PGE interface and that the Blue Marmots could either: 1) deliver to PGE via the BPA-PGE interface, which would require a second transmission "wheel" on the Bonneville Power Administration ("BPA") system; or 2) request a System Impact Study ("SIS") to determine if upgrades could increase the capacity of the PACW-

PGE interface (since the interface's existing capacity has been dedicated to the EIM by PGE). The Policy Testimony goes on to explain PGE's EIM participation and summarizes the results of the SIS. PGE's Policy Testimony relies heavily on the results of the SIS and its assertion that the PACW-PGE interface should be completely dedicated to EIM transfers. It also addresses PGE's views on the Blue Marmots' Legally Enforceable Obligations ("LEOs").

Q. Please summarize your response to PGE's Policy Testimony.

A. First, I think that PGE has taken an unreasonably restricted view of the options it has to manage the Blue Marmots' output. Given that there is currently no available transfer capability ("ATC")[3] on the PACW-to-PGE path, PGE's Policy Testimony alleges that PGE's only options for accepting the power at the PACW.PGE point-of-delivery ("POD") are: 1) the Blue Marmots funding a 300-mile transmission project identified in the PGE SIS;[4] or 2) PGE relinquishing certain transmission rights, which PGE says will result in "severely eroded" EIM benefits.[5] This narrow set of available options is a product of PGE's own actions, at least partially, and PGE has not considered other options that would enable it to meet its purchase obligation under PURPA while allowing it to maintain its current level of EIM benefits.

---

3 ATC is the amount, in megawatts ("MW"), of transfer capability that is available to be reserved on a given transmission path over a given increment in time. It is a transmission capacity product that can be calculated on a long-term, short-term, firm- and non-firm basis. Relevant to this case, there is no long-term firm ATC over the PACW-PGE interface and the Blue Marmots and PGE disagree as to what that means regarding PGE's obligation to accept the Blue Marmots' output.

4 The length of the transmission upgrade has been cited as 250-miles in the SIS and 300-miles by PGE's testimony. I use 300-miles in this testimony for consistency.

5 PGE/100, Greene-Moore/4

My second concern pertains to the Policy Testimony's description of PGE's actions when ATC was made available on the PACW-to-PGE path. PGE said they would not counter-sign the Blue Marmot PPAs because there was no ATC on the PACW-to-PGE path. However, when ATC became available on the PACW-to-PGE path PGE chose to reserve the transmission to increase its EIM-dedicated capacity rather than reserving transmission on behalf of the Blue Marmots. PGE's view appears to be that as additional transmission on its own system becomes available, it will purchase and use the transmission for whatever purpose it desires, except to accept the Blue Marmots' output. This is concerning not only for the Blue Marmots and other QFs, but for the long-term efficient use of the PGE transmission system. This concern regarding PGE's use of its existing and future transmission rights on its own system is amplified by the analysis I present later in this testimony, which shows that the transmission that PGE *already has* in the EIM is not frequently used.

Lastly, I disagree with PGE's claim that the Blue Marmots have not made all necessary transmission arrangements because the Blue Marmots will not be able to schedule power across the PACW-PGE interface.[6] This scheduling requirement wrongly shifts responsibility for arranging transmission on PGE's system to the Blue Marmots. The Blue Marmots made the appropriate PURPA-required transmission reservations to PGE's system, and any operational challenges associated with scheduling power are PGE's to resolve.

Q. Please explain why you see PGE's two alternatives for accepting power at the PACW POD (the 300-mile transmission project or giving up EIM transmission rights) as unreasonably limited.

---

[6] PGE/100, Greene-Moore/17.

A. I see these two options as too limited for technical and policy reasons. I cover the technical reasons in my reply to the EIM Testimony (Section III) and the Transmission Testimony (Section IV). PGE limits the options available to manage the Blue Marmot power as a way of avoiding its purchase obligation, while ignoring alternative uses of the power and transmission. PGE also overstates its claim that it cannot simultaneously purchase power from the Blue Marmots while maintaining participation in the EIM. There are numerous ways in which PGE can manage the Blue Marmots' output. For example, one way that PGE could choose to manage the power is by reselling it to a third-party utility. PGE does not include this among its options. Alternatively, PGE could resell a *portion* of the power to a third-party and use a *portion* of it to serve native load – again, not considered among PGE's options. Another way to manage the power is through the concept of displacement. At the end of the day, PGE is the entity best positioned figure out the most economical solution.

Q. Explain how the displacement approach might work.

A. I see no reason why the Blue Marmot power cannot be used by PGE as a surrogate for power PGE would otherwise ship to market. This may be accomplished in support of EIM transactions or any other off-system sales PGE may undertake. I am not aware of anything in PURPA that stipulates that the power a utility is obligated to purchase from a QF must physically move onto the purchasing utility's system. I note that in FERC Order No. 69 (implementing PURPA), FERC describes how the power a utility purchases need not move physically onto its system but may be used on the system to which the QF is physically interconnected and moved to the purchasing utility by displacement. By the same token, nothing stops a purchasing utility from using the purchased power in support of an off-system transaction.

Q. In what other ways is PGE limiting the options that PGE has available to it or overstating their costs?

A. PGE's SIS performed in response to the point-to-point ("PTP") transmission service request ("TSR") on the PACW-to-PGE path is flawed as a technical matter, and even if accurate, provides no basis for mitigating PGE's purchase obligation. I address the SIS in detail within my response to the Transmission Testimony, but, to summarize the main points here as well, PGE has:

(1) Not considered transmission expansion options that could more effectively increase the total transfer capability ("TTC")[7] of the PACW-PGE interface relative to the option considered in the SIS;

(2) Arrived at an unreasonable study conclusion that a 300-mile generation tie line is needed to deliver the output – an impractical conclusion that overstates cost implications;

(3) Introduced a transmission service study conducted in accordance with FERC and NERC rules, methods, and standards into a state-jurisdictional proceeding and has cited debatable findings as fact, consistent with (1) and (2), above, thereby complicating the record; and

(4) Mischaracterized the TSR and resulting SIS as something the Blue Marmots were obligated to request from PGE Transmission when PGE Merchant should have been the entity requesting the study since the Blue Marmots had

---

[7] TTC is the MW-value of power that can be reliably transferred across all of the transmission lines that make up a given transmission path or interface. PGE determines TTC of its transmission paths using FERC methods developed through and enforced by the North American Electric Reliability Corporation ("NERC").

already made the appropriate transmission arrangements to the edge of the PGE system.[8]

Endorsing a process with such obvious infirmities does not promote good policy outcomes.

Q. Might some of these options, such as using the resource in the EIM or adding transmission, increase PGE's costs?

A. PGE has not demonstrated this. Based on what has been presented, it appears that PGE can accept the Blue Marmot output, avoid transmission upgrade costs altogether, and still maintain roughly the same EIM benefits.

I have a healthy skepticism toward PGE's position that there will be significant cost shifts, which is why I recommend that if this Commission finds PGE's concerns and purported costs as reasonable, then PGE should only be permitted to address them on a forward-going basis – perhaps through a more sophisticated avoided cost pricing methodology. For projects, such as the Blue Marmots, which have arranged for delivery to PGE's system, PGE should use its best judgement to manage their output in the most cost effective way possible.

Q. Is PGE's position regarding the Blue Marmots' obligation to deliver its output to PGE's border inconsistent with prior positions by PGE?

A. Yes. PGE has previously agreed that "an off-system QF…is responsible for arranging and paying for the transmission required to deliver its off-system QF energy to the Portland General border."[9]

---

8 When it is relevant, I use the term "PGE Transmission" to refer to PGE's transmission function and "PGE Merchant" to refer to its merchant function. When such a distinction is not warranted, I refer to the company as PGE.

9 PáTu Wind Farm, LLC, 151 FERC ¶ 61,223 at n.52 (citing PGE General Request for Rehearing at 9, n.24).

Q. The second issue you have with the Policy Testimony deals with the need for PGE to balance its desire to add transmission for EIM participation with its QF obligations. Please respond.

A. I have no better understanding of PGE's plans in this area now than when I prepared my Direct Testimony. PGE responded that when 15 MW of new ATC became available on the PACW-to-PGE path that the ATC could not be directed to just the Blue Marmots because PGE has obligations to other QFs delivering to the same location. PGE has not explained, however, what its policy will be for these other QFs with LEOs delivering to the same POD or even if it will use the transmission for any of those QFs. PGE's Policy Testimony couches the issue as a QF versus QF problem, when really it remains a problem of PGE unnecessarily prioritizing the reservation of transmission service for PGE's future EIM participation and continued Market Based Rate ("MBR") authority[10] over its QF obligations.

PGE's Policy Testimony says that the 295 MW of firm PTP rights PGE holds on the PACW-to-PGE path are less than the 418 MW they originally targeted for EIM-dedicated capacity.[11] PGE uses this simple justification for reserving all of the transmission on the path and dedicating it to the EIM. PGE's rationale falls short because: 1) the original target for EIM capacity on that path may not be optimal for PGE's customers; and 2) a target set *by* PGE *for* PGE does not mean it is absolved of

---

10 PGE can participate in the EIM using the ATC Methodology or the Interchange Rights Holder Methodology. PGE's chosen approach, the Interchange Rights Holder Methodology, reserves PTP transmission and dedicates it 100% to the EIM (blocking the transmission from serving multiple uses). On the other hand, the ATC Methodology is more efficient in the sense that it allows transmission to be used for other purposes then "releases" any unused portions into the EIM.

11 Note that since the filing of my Direct Testimony PGE has reserved an additional 15 MW of transmission capacity on the path, bringing its total reservations to 310 MWs of the 320 MW of total (summer) capacity.

its other responsibilities. Also, as you will see later, the amount of transmission that PGE currently has in the EIM is not being well utilized so the stockpiling of EIM-dedicated transmission capacity is not reasonable, especially since PGE has options for EIM participation that could maintain the vast majority of EIM transfers over the path while still allowing PGE to accept Blue Marmots' output.

What I am voicing, more generally, is concern with the practice of unnecessarily reserving transmission solely for use in the EIM and preventing that transmission capacity from being used for any other purpose. PGE does this by utilizing the Interchange Rights Holder Methodology for EIM transfers over the PACW-to-PGE path.[12] The other method that is available to PGE puts unused transmission into the EIM "as-available" (*see* the "ATC Methodology" description in the PGE EIM Testimony on page 11). By reserving transmission solely for use in the EIM using the Interchange Rights Holder Methodology, the transmission is "locked up" so PGE (and its resources) and other EIM entities (and their resources) can use the transmission in combination with the EIM real-time dispatch to economically serve loads. However, anyone seeking longer-term use of that transmission, such as the Blue Marmots, are locked out.

This tension exists because, from a system planning and contracting perspective, transmission in the West is generally managed through the traditional contract path construct. Typically, transmission is reserved by an entity seeking to

[12] The Interchange Rights Holder Methodology is a form of EIM participation where the transmission provider commits firm transmission to the market, and that transmission is exclusively dedicated to that purpose. PGE has selected this method for its EIM participation, as explained further in its testimony.

deliver a specific resource to a specific delivery point, or to facilitate a specific bi-lateral power transaction. In stark contrast, here we have a utility reserving almost all of the capacity on a given path and *hoping* that the transmission is well utilized in a real-time energy market. PGE cannot control the utilization of the path in the EIM and, as my analysis shows, PGE overestimated the amount of transmission that it needs to *efficiently* facilitate economic EIM imports[13] on the PACW-PGE interface.

Q. You state that the Blue Marmots will have fulfilled their transmission obligations by delivering power to the PACW-PGE Interface. PGE asserts that the Blue Marmots' transmission obligation will not be complete until they also schedule power on the PGE system. Do you agree?

A. No. PGE's scheduling argument confuses the facts surrounding what is required of the Blue Marmots. To see this, we must revisit the difference between the role of transmission reservations and transmission schedules. A *transmission reservation* is typically made well in advance – years or months prior to any actual energy transaction taking place.[14] It entitles the transmission customer to a certain amount of transmission capacity, represented in MW, from a point on the transmission system to another point on the transmission system for a given time period. A *transmission schedule* is a much shorter-term operational tool that, in quantity, aligns with the expected output of the generator for a given hour or series of hours – essentially serving as a request to complete a shorter-term transaction. The transmission schedule can be submitted, more or less, a day- or an hour-ahead of the transaction, and it requires a *transmission reservation* equal to or greater than the *transmission schedule*

---

[13] EIM imports are EIM transfers into the PGE Balancing Area. In this instance, those transfer occur on the PACW-PGE interface, which connects the PACW Balancing Area with the PGE Balancing Area.

[14] Transmission can be reserved on a short-term basis, but this is not applicable to the Blue Marmots.

being arranged. You cannot schedule power on a transmission system without having the right to do so, and that right is conveyed via a transmission reservation. This explanation is consistent with what PGE represented in its Transmission Testimony.

Q. Why is this distinction important given that PGE states that the Blue Marmots will not be able to schedule their power?

A. In the Transmission Testimony, PGE acknowledges that the Blue Marmots have *reserved* capacity on PacifiCorp's system, which gives the Blue Marmots the right to *schedule* power on that particular segment to the PACW-PGE interface. However, PGE says that since there is no ATC on the PACW-to-PGE path, the power cannot go across the PACW-PGE interface and, according to PGE, "despite having made a reservation on PacifiCorp's system, the Blue Marmots would be unable to schedule delivery of their output to PGE … and PGE cannot receive their output".[15]

This assessment of the Blue Marmots' ability to schedule power is technically accurate, but only if you consent to certain assumptions. It assumes that the Blue Marmots, or someone other than PGE, is responsible for making the "second" transmission reservation on the PGE transmission system from the PACW.PGE POR (at the PACW-PGE interface) to the PGE POD.[16] This reservation, if made, would enable the complete scheduling of the Blue Marmot power to PGE load. As such, if PGE were to make this reservation or otherwise arrange transmission using its existing rights, then PGE's scheduling argument deflates and the Blue Marmot power could indeed be scheduled to PGE's load. PGE begins its logic where it seeks to end – the argument is circular and is based on PGE not taking appropriate action.

---

15 PGE/100, Greene – Moore/17

16 As explained in PGE's Transmission Testimony, the PacifiCorp balancing area PACW.PGE POD/POR is mapped to the PGE balancing area PACW POD/POR.

There is no other action that I am aware of that the Blue Marmots should, or could have, taken in this area to facilitate a transmission reservation to PGE's load. PGE agrees that there is no way for the Blue Marmots to reserve transmission across the PACW-PGE interface.[17] The Blue Marmots made the correct transmission reservation on the PacifiCorp system, which leaves only the PGE system reservation, and that is not the Blue Marmots' responsibility.

III. REPLY TO EIM TESTIMONY

Q. Do you have any general observations regarding the EIM Testimony?

A. Yes. In my Direct Testimony, I assert that PGE could manage its EIM participation in a manner that accommodates delivery of the Blue Marmots' output. PGE's response presents technically misleading and unsubstantiated conclusions regarding the levels of transfers that have taken place on the PACW-to-PGE import path and PGE's dependence on the path for EIM benefits. PGE also does not support its claim that PGE's EIM benefits are dependent on its ability to maintain MBR authority. These arguments are important to PGE's position that *any* allocation of transmission to the Blue Marmots would mean they could not "participate meaningfully" in the EIM.

In the summer months, the time of year when the PACW-to-PGE import path is constrained, its TTC is 320 MW.[18] Since PGE submitted its testimony, is has reserved an additional 15 MW of point-to-point transmission on the path, bringing its

---

[17] Blue Marmot/401, Moyer/3-4 (PGE Response to Blue Marmot Data Request No. 134: There is no "transmission service across the interface.").

[18] PGE can accept the Blue Marmot power in the winter months – there is sufficient ATC during that time according to the SIS.

total reserved capacity to 310 MW.[19] At least 295 MW of this transmission is dedicated to EIM transfers, meaning it serves no other purpose than to facilitate real-time economic exchanges via the EIM. My testimony shows that this 295 MW of EIM-dedicated transmission is not well utilized by the market – it often sits idle. Transfers greater than 200 MW happen in only 10% of market intervals and transfers greater than 250 MW happen only 3% of the time. This means there is copious amounts of EIM-dedicated transmission on the PACW-to-PGE import path that goes unused for significant period of the time. I believe this transmission could be used for dual purposes, first importing the Blue Marmot power when the Blue Marmots are generating, and then second, facilitating EIM imports when the Blue Marmots are not generating (and imports are economic). PGE was, and still is, excessively bullish on the amount of transmission capacity it needs to reserve on the PACW-to-PGE import path to facilitate *efficient* EIM participation.

If PGE were to reallocate 50 MW of its 310 MW of existing transmission rights on the PACW-to-PGE path to the Blue Marmots and manage this portion of its EIM transmission using the ATC Methodology, there may be very little, or even no, reduction in EIM benefits to its customers.[20] This is especially true since the Blue Marmots have, roughly, a 30% capacity factor and thus, 70% of the energy associated

[19] The remaining 10 MW is set aside for PacifiCorp's use serving load in PGE's area. PGE had 295 MW of PTP reservations when this proceeding started, but now that number is 310.

[20] PGE now has 310 MW of long-term firm transmission rights on the path. If PGE were to the transfer 50 MW to the Blue Marmots, PGE would still have 260 MW of long-term firm transmission rights that it could dedicate to the EIM. I explain later, in certain market intervals doing this will not necessarily change the level of transmission actually available to the EIM.

with the 50 MW of Blue Marmot-dedicated transmission can be *repurposed* for the EIM when it is not being used by the Blue Marmots. The inverse is not true – EIM-dedicated transmission, as currently managed by PGE, cannot be repurposed for the Blue Marmots. The first route is clearly more efficient from a transmission-use standpoint. The transmission will be used more often if dedicated to the Blue Marmots than if it remains idle in the EIM, and based on PGE's EIM operations to date, this use will not significantly impact PGE's EIM benefits.

Finally, even if PGE did dedicate transmission to the Blue Marmots, it would not drop it below its 200 MW commitment to FERC supporting its MBR Authority. If it did drop below that level, say, because of other QFs delivering across the interface, PGE provides no evidence supporting its conclusion that its EIM benefits would be compromised – PGE has not proven that EIM benefits are dependent on MBR Authority. Plus, if it so important to PGE to maintain MBR Authority, it could seek to regain it with a filing at FERC. There are multiple scenarios for PGE to continue to participate in the EIM in much the same manner that it does today, while still accepting the Blue Marmot output at the PACW-PGE interface.

Q. Do you have any other concerns surrounding how PGE is portraying its EIM benefits?

A. Yes. PGE also fails to consider the cost associated with it procuring PTP transmission on the PACW-to-PGE path that is solely dedicated to the EIM. PGE should be expected to explain its EIM benefits in terms of *net* benefits, accounting for the cost of transmission.

Q. Why are PGE's conclusions regarding the frequency of transfers on the PACW-to-PGE import path incorrect?

A. PGE produces Table 1 in the EIM Testimony as its first and primary piece of evidence to support its position that PGE frequently imports over the PACW-to-PGE path. The data is from October, November, and December of 2017 – the first three months of PGE EIM operations and the months available at the time of PGE's testimony. Based on the data, PGE claims that the capacity that PGE has dedicated to the EIM is used and useful, and that if any amount of that capacity was used to accept the Blue Marmots' power, PGE's EIM benefits will be significantly compromised.

I have reviewed the analysis and underlying data PGE used to develop Table 1.[21] I conclude that PGE has misrepresented the magnitude and frequency at which imports have occurred on the PACW-to-PGE path.

First, the analysis used to develop Table 1 represents that, if a transfer occurred in a single 5- or 15-minute market interval, then the transfer occurred at that level for the *entire* hour. In essence, PGE's Table 1 shows a need for an hour's worth of transmission based on the transfers in a single 5- or 15-minute market interval. In the EIM, there are 16 market intervals in every hour: twelve 5-minute "real-time" intervals and four 15-minute intervals. The correct way to calculate the utilization of a path is to compare the transfer in a given market interval, or set of intervals, against the total market intervals in the period over which the comparison is being drawn. This gives an accurate representation of the frequency of imports over a given period. PGE's analysis, on the other hand, represents the transfer "need" for the entire hour when the "need" could have been for 5 or 15 minutes, which overstates the frequency

[21] Blue Marmot/401, Moyer/5 (PGE Response to Blue Marmot Data Request 159).

of imports on the PACW-to-PGE path (since they can vary within an hour) and the implied value of the EIM-dedicated transmission.

By way of example, in a given hour if imports were 150 MW for a given 5-minute interval, and then zero MWs for the remaining eleven 5-minute intervals, the energy transfer across the path for that first 5-minute interval is 150 MW, but the total energy transfer across the path is 12.5 MWh *for the hour*. PGE implies that the value of the transmission in this *hour* is 150 MW.[22] In reality, the path enabled a small total energy transfer with one significant interval transfer, and it was utilized for only 1/12th of the available intervals in the hour. In the analysis that follows this summary, I recalculate PGE's metrics using a factually representative metric based on the frequency and magnitude of transfers during available market intervals.[23]

Second, in the third column PGE represents the "% of Import Hours that the Import Reached or Exceeded 200 MW". PGE misleads us by calculating this as the percentage of *import hours*. PGE should calculate this as the percentage of *total intervals in the month*. Here is why: if there had been only 100 15-minute import intervals in a month, and 99 of them had imports above 200 MW, this result would read 99% (99/100) as calculated by PGE – an overstatement of how used and useful the path is. For 15-minute intervals, for which there is about 3,000 in a 31-day month, the path's 99 import intervals above 200 MW is actually 99/3000, or about 3%. Thus, a better representation of the frequency of imports at a certain MW-level is to divide

---

[22] The 12.5 MWh is calculated as (1/12 hours) * 150 MW + (11/12) hours * 0 MW from the remaining intervals, totaling 12.5 MWh.

[23] Alternatively, PGE could have divided by the total number of intervals in a given month. This would also have appropriately represented the utilization of the path.

by the number of market intervals in a given month or time period, as I have done below.[24] This compares how often the path is used for EIM transfers over the period it was *available* for that use – a much better indicator of utilization.

Q. Please summarize your analysis of the EIM transfer data.

A. I performed the same analysis as PGE, correcting the metrics, as described above, and extending it out through the end of April 2018. A comparison of the two calculation methodologies is provided in Table 1.[25] My analysis included in this testimony was performed for the 15-minute interval, although a separate analysis of the 5-minute interval provided very similar results. This analysis is important because it shows that EIM imports on the PACW-PGE interface do not happen frequently, and when they do happen they occur at relatively low magnitudes.

The 200 and 276 MW thresholds in the table are repurposed from PGE's original Table 1. The 200 MW threshold is relevant because that is the EIM-dedicated transmission capacity that PGE asserts it must maintain on the path to preserve its MBR Authority. My analysis shows how frequently imports exceed that threshold. For example, in October of 2017, imports exceeded that 200 MW threshold in only 6% of intervals. PGE calculated that 21% of *import hours* had transfers above the 200 MW threshold for that same month, which overstates how often the path is used at or above that threshold. The 276 MW threshold is only relevant because that is the MW capacity of transmission that PGE had on the path at the time of its MBR Authority

---

[24] Note that my analysis uses the same data as PGE, but expanded to include Jan – April of 2018. The additional data was added because there are four additional months of EIM participation available. This data was gathered from the CAISO OASIS.

[25] Data is available from the CAISO OAISIS, see Energy/EIM Transfer by Tie, and filter data for the PACW-to-PGE import path (http://oasis.caiso.com/mrioasis/logon.do)

filing. It has since expanded that capacity, but to maintain consistency with PGE's Table 1 that threshold value was retained in my table. In the subsequent analysis, I also mention a 250 MW threshold – utilization above that mark was calculated the same way as the 200 MW and 276 MW thresholds, and the 250 MW mark roughly aligns with the EIM-dedicated capacity that PGE would have left if it transferred 50 MW to the Blue Marmots.[26]

Table 1: Comparison of EIM Import Calculations

PGE Approach *(Based on Max Hourly Import from 5- or 15-min. market)*			
Transfers by Month	% of Hours Import Occurred	% of Import Hours that the Import Reached or Exceeded 200 MW	% of Import Hours that the Import Reached or Exceeded 276 MW
October-17	78%	21%	8%
November-17	81%	24%	8%
December-17	85%	37%	20%
Moyer Testimony Approach *(Based on Imports of 15-min. market (RTPD))*			
Transfers by Month	% of Total Intervals Import Occurred	% of Total Intervals that the Import Reached or Exceeded 200 MW	% of Total Intervals that the Import Reached or Exceeded 276 MW
October-17	50%	6%	2%
November-17	50%	6%	2%
December-17	63%	16%	7%
January-18	33%	2%	0%
February-18	35%	5%	2%
March-18	33%	4%	1%
April-18	28%	1%	0%
AVERAGE	42%	6%	2%

Q. Based on these two analyses, what observations do you have regarding historic imports on the PACW-to-PGE path for October through December?

[26] This is a conservative view of the effective transmission that PGE would have left in the EIM since the Blue Marmot-dedicated transmission could still be used in the EIM via the ATC Methodology when the Blue Marmots are not generating.

A. The first observation is that PGE's calculation methodology significantly overstates the frequency and magnitude of imports. PGE's analysis concludes that imports have occurred in 81% of the hours (taking the average of each month). My analysis shows that imports occur much less frequently – they happened in about 54% of 15-minute intervals and 59% of 5-minute intervals from October through December. Thus, on a transmission path that is 100% dedicated to the purpose of facilitating imports, imports occurred in roughly 50% of available intervals in the first three months of EIM operations.

More important to this proceeding is the *magnitude* of imports. My analysis shows that imports during October through December occurred at or above 200 MW in about 9% of 15-minute intervals, and above 276 MW in only 4% of 15-minute market intervals (again, on average). PGE overstates the magnitude of imports by three- and four-fold for the 200 MW and 276 MW threshold, respectively.

Looking only at October through December, there is value in PGE's EIM participation – imports would not occur otherwise. However, those imports are less than 200 MW more than 90% of the time and thus, the value of this import path is not dependent on PGE having significantly more than 200 MW of dedicated EIM transfer capability as economic transfers above that level do not occur frequently.

Q. Considering the months since January 2018, do you have any additional observations?

A. The frequency and magnitude of import hours appear to be decreasing in the months starting with January 2018, as compared to the first months of PGE's EIM participation. This is counter to PGE's prediction that its EIM transfers were going to increase after it: 1) began integrating its own wind resources; and 2) operated during a complete set of winter months during which the region experiences high loads. In the first four months of 2018 since the PGE testimony, the import path has been used for only 32% of 15-minute market intervals, on average, and imports have exceeded 200 MW for only 3% of 15-minute market intervals. Transfers on the path almost never exceed 276 MW, let alone the 295 MW PGE has assigned to the EIM through the Interchange Rights Holder Methodology.

From this data, we can conclude that more than 97% of PGE's imports require less than 250 MW of transmission over the first seven months of EIM participation. Importantly, this includes March and April when California is alleged to have significant over-generation issues creating economic opportunities for low-cost solar.

Q. Does this mean that the PACW-to-PGE import path and PGE's transmission rights that is has dedicated to the EIM are not being fully or even partially utilized?

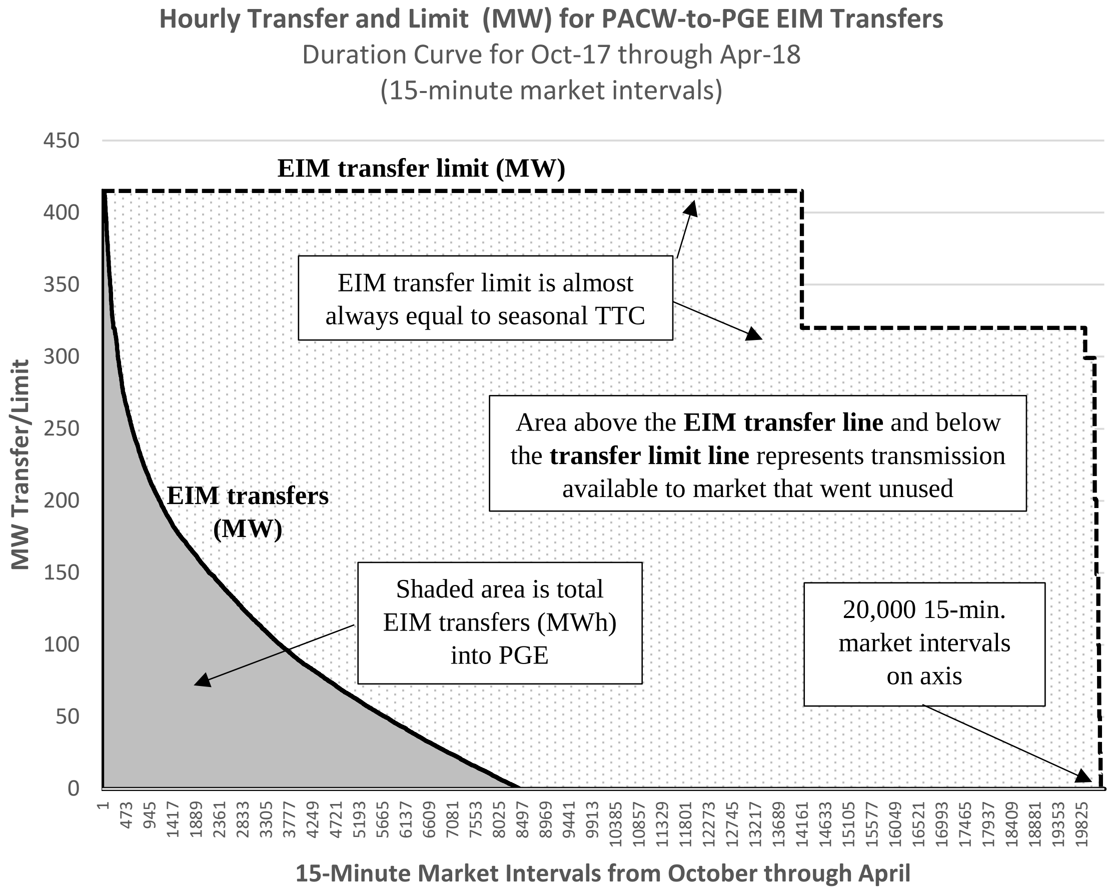
A. Yes, based on this historical data PGE has, to some extent, over-procured EIM-only transmission. A good way to demonstrate this is through a duration curve. To develop this information, I combined the EIM transfer data for the PACW-to-PGE path with EIM transfer limit data for the same.[27] Both datasets, starting from October 1, 2017 going through the end of April 2018, are sorted from largest to smallest in Figure 1 for the 15-minute market – they are not shown chronologically. This gives us a visual of how often and to what extent the PACW-to-PGE path is used for EIM imports.[28]

---

[27] Data is available from the CAISO OAISIS, see Energy/EIM Transfer Limit by Tie, and filter data for the PACW-to-PGE import path (http://oasis.caiso.com/mrioasis/logon.do)

[28] The results were not significantly different for the 5- and 15-minute markets, so I only include the 15-minute analysis.

Figure 1: Hourly Transfer and Limit for PACW-to-PGE Imports



The solid black line represents EIM transfers, in MW, for each market interval sorted largest to smallest. The EIM transfer limit is represented by the dashed black line (with values sorted largest to smallest values for the October through April period). We can draw several conclusions from this figure and its supporting data:

(1) Relative to the EIM transfer limit of the path, transfers are low and the EIM transfer limit, most of which is EIM-dedicated transmission, is not well utilized – the dotted area between the two lines represents the transmission capacity dedicated to the EIM that went unused in the 15-minute market intervals;

(2) The EIM transfer limit has been equal to the path TTC for almost every interval since PGE joined the EIM; and

(3) Since October, the PACW-to-PGE path has an average 15-minute market EIM transfer limit of 384 MW (this is greater than the 320 MW summer TTC because of the higher winter TTC). The EIM-dedicated capacity has accommodated an average of 44 MW of transfers over that same period – an average transmission "utilization factor" of about 11%. The utilization factor for the Blue Marmots will be about three times that even though the solar resources will not generate at night. This means that, on a per-MW basis, the Blue Marmots will actually use PGE's transmission system more often than the EIM has historically used the path for EIM imports to PGE. There is also the added benefit that when the Blue Marmots are *not* using the transmission, it could be repurposed and used by the EIM, so the utilization in the Blue Marmot-then-EIM approach will likely be even higher.[29]

What this all means is that the transmission that PGE has already dedicated to the EIM is not well utilized, and that using a small portion of that transmission to deliver the Blue Marmots' output will not likely have a substantive impact to PGE's EIM imports or benefits, especially since that transmission can still be used by the EIM when the Blue Marmots are not generating (or are generating at reduced levels).

Q. On page 19 of the EIM Testimony, PGE introduces results from the E3 2018 scenario that predicts imports will occur in 69% of the hours and at or above

[29] While I have not made this determination, PGE has argued that there are contractual limitations on its ability to use the Blue Marmot net output in the EIM. I have argued that PURPRA appears to allow such use of the output, so correcting those contractual limitations would be a reasonable course.

200 MW for 72% of import hours. Does your analysis of 2018 data to date support this finding?

A. No. Based on the first four months of 2018, the study results and the actual historic transfers do not align. Average hourly imports in 2018 have occurred in 46% of hours (based on averaged 15-minute market data), and average hourly imports at or above 200 MW have occurred in only 2% of hours – much less than the 69% of hours forecasted in that study.[30]

Q. PGE claims that if it lost transfer capability on the PACW-to-PGE path, "it is unlikely the Company would be able to participate meaningfully in the EIM". One justification that PGE gives is that its MBR authority from FERC is conditioned on the Company's commitment to 200 MW of firm transfer capability on the PACW-to-PGE path. What are your reactions to this?

A. The claim that PGE would not be able to participate meaningfully in the EIM is unsubstantiated and PGE has provided no evidence that ties its EIM benefits to its ability to maintain MBR authority within the EIM.

First, it is notable that PGE can accommodate the Blue Marmot power without dropping below its 200 MW commitment for MBR Authority on the PACW-to-PGE import path – it has 295 MWs of EIM-dedicated PTP transmission and 15 MW of additional PTP transmission.[31] This means its EIM-dedicated transmission would still be 260 MW if it used 35 MW of current EIM-dedicated transmission rights, plus 15 MW of its newly acquired PTP transmission, to accommodate the Blue Marmots.

---

[30] These average hourly numbers were calculated by determining the MWh of imports that occur in a given hour of EIM operation.

[31] At this time, it is unclear if PGE has added this 15 MW of transmission to its EIM-dedicated capacity.

Second, even if PGE elected to participate in the EIM without MBR authority, it fails to draw a link as to how that change would impact its ongoing benefits.[32] MBR authority provides PGE the authority to bid into the relevant market, in this case the EIM, at market-based rates, rather than at cost-based rates. Utilities have participated in the EIM without MBR authority, including PacifiCorp, NV Energy, and Arizona Public Service Electric Company, and still accrued EIM benefits. The lack of MBR authority restricted those utilities from bidding a price higher than a unit's Default Energy Bid, as calculated pursuant to rules of the California Independent System Operator ("CAISO"). The CAISO's Default Energy Bids are intended to reflect the unit's cost-based bids.[33] The ability to submit market-based bids may seem compelling, but my understanding is that most market participants that do have MBR Authority submit cost-based bids into the EIM.

Furthermore, my understanding is that PGE's EIM benefit studies, such as the one referenced by PGE in its testimony, *assume* that PGE submits cost-based bids. Thus, the benefits PGE has forecasted through this modeling assumes that PGE does not have MBR Authority, which means that PGE has failed to provide any evidence stating that it accrues incremental benefits through a market-based bidding strategy.[34]

---

32 See PGE/100/Sims – Rodehorst – Sporborg/4, line 9-11. In this example, and others, PGE does not explain why not transacting at MBR would materially impact its benefits.

33 See Blue Marmot/402 (Memo from Keith Casey, CAISO Vice President of Market and Infrastructure Development to ISO Board of Governors RE: Decision on commitment costs and default energy bid enhancements).
Proposal (March 14, 2018), available here:
http://www.caiso.com/Documents/Decision_CCDEBEProposal-Memo-Mar2018.pdf

34 See Exhibit 201 to Testimony of Brett Sims, Aaron Rodehorst and Pam Sporborg (EIM Testimony).

Therefore, PGE has not demonstrated that submitting cost-based bids would result in any changes or reduce its EIM benefits.

Third, PGE could potentially maintain its MBR Authority by making the appropriate filings at FERC. FERC's order requires PGE to "submit a change in status filing if there is a decrease in the amount of firm transmission capacity committed to EIM transfers between PACW and" PGE.[35] PGE could submit a change to maintain its MBR status filing and commit less than 200 MW to EIM transfers from PACW to PGE.

PGE has not provided evidence or data to support its claim that accepting the Blue Marmot output over the PACW-to-PGE path would prevent PGE from participating meaningfully in the EIM.[36] There are multiple options for PGE to continue to participate in the EIM in much the same manner that it does today.

Q. Earlier you suggest that PGE should transfer a portion of its EIM-dedicated transmission to the Blue Marmots on the basis that it would be a more efficient use of the system. Why do you say that?

A. The path utilization analysis I presented above assumes that if PGE used transmission on the PACW-to-PGE path to accept the Blue Marmot output, that transmission would *not* be available for any other purpose. This is a conservative view, on my part. In actuality, the Blue Marmots will have, approximately, a 30% capacity factor which means roughly 70% of the Blue Marmot-dedicated transmission capacity will go unused and can re-enter the EIM to be used by PGE as it currently is today. This is

---

[35] Order on Market Power Analysis, Notice of Change in Status and Market-Based Rate Tariff changes, FERC, September 28, 2017; Dockets ER10-2249-007 and ER17-1693-000, p. 18, available here: https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14694334

[36] PGE/200, Sims – Rodehorst – Sporborg/19.

because PGE can participate in the EIM using the ATC Methodology. If PGE takes simple actions like this, the Blue Marmots will not significantly impact its EIM operations or benefits.

Q. You state that PGE should consider using the ATC Methodology to participate in the EIM market on the PACW-to-PGE path. PGE said that if they used this approach, then other transmission customers or off-system QFs could reserve and schedule some or all of the capacity, and the capacity would not be available for EIM exchanges. Please respond to this argument.

A. First, I am not suggesting that PGE completely shift to the ATC Methodology – a portion of the transmission capacity can still be EIM-dedicated through the Interchange Rights Holder Methodology. Second, recall that this issue is relevant for only the summer months during which the PACW-to-PGE import path is reduced to 320 MW TTC (the path is not constrained in the winter because there is sufficient ATC). Third, the Blue Marmots' output will not be scheduled across the path at 100% of its 50 MW capacity for all hours. Anytime the Blue Marmots generate less than their maximum output, that transmission will be available for the EIM. Given the capacity factor of the Blue Marmots, this will happen approximately 70% of the time, meaning that the Blue Marmots will only consume, on average, 4.5% of the PACW-to-PGE TTC, on a megawatt-hour basis, assuming the constraining 320 MW TTC. The impact is even lower than that considering that the TTC is 415 MW during winter. Thus, the potential maximum impact of the Blue Marmots on EIM transfers is quite low, and given EIM transfers to date, the anticipated impact is negligible.

Q. How would the ATC Methodology approach release the Blue Marmots' transmission back into the EIM?

A. PGE's approach for determining the EIM transfer capability for the ATC Methodology is based on the following equation: [37]

EIM Transfer Capability = Path TTC – Implemented Interchange Schedules on the path + Counter Schedules of the opposite path

The ATC method allows counter schedules to add to the EIM transfer capability. Counter schedules are the sum of schedules in the opposite direction of the path. It also allows un-used transmission to be released back in to the EIM when interchange schedules are less than the reserved capacity. Since the Blue Marmots will generate at roughly a 30% capacity factor, it will not use all their transmission dedicated and this transmission can be made available to the EIM. Plus, when there are counter schedules (from PGE to PACW) they could actually "cancel out" the Blue Marmot schedule and the EIM transfer capability would not be impacted.

Thus, if PGE were to assign transmission to the Blue Marmots there could be many hours where PGE will have EIM transfer capability equal to the TTC of the PACW-to-PGE import path – essentially business-as-usual. PGE fails to consider this counter-factual scenario when it states as fact that EIM transfer limits *will* be lower if it dedicates transmission to the Blue Marmots.

Q. PGE indicates that 295 MW is the amount of transmission that it has dedicated to the EIM. Can the amount of transmission be more than that?

A. Yes, when the ATC Methodology is combined with the Interchange Rights Holder Methodology. The data from the EIM transfer analysis above shows this – the import path is almost always equal to the TTC (which varies seasonally but is greater than 295 MW). This is likely because the ATC Methodology includes counter schedules,

[37] Blue Marmot/401, Moyer/13-14 (PGE Response to Blue Marmot Data Request 176).

which adds those schedules back into the transfer limit calculation and the amount of transmission available for the EIM is increased back to its TTC.

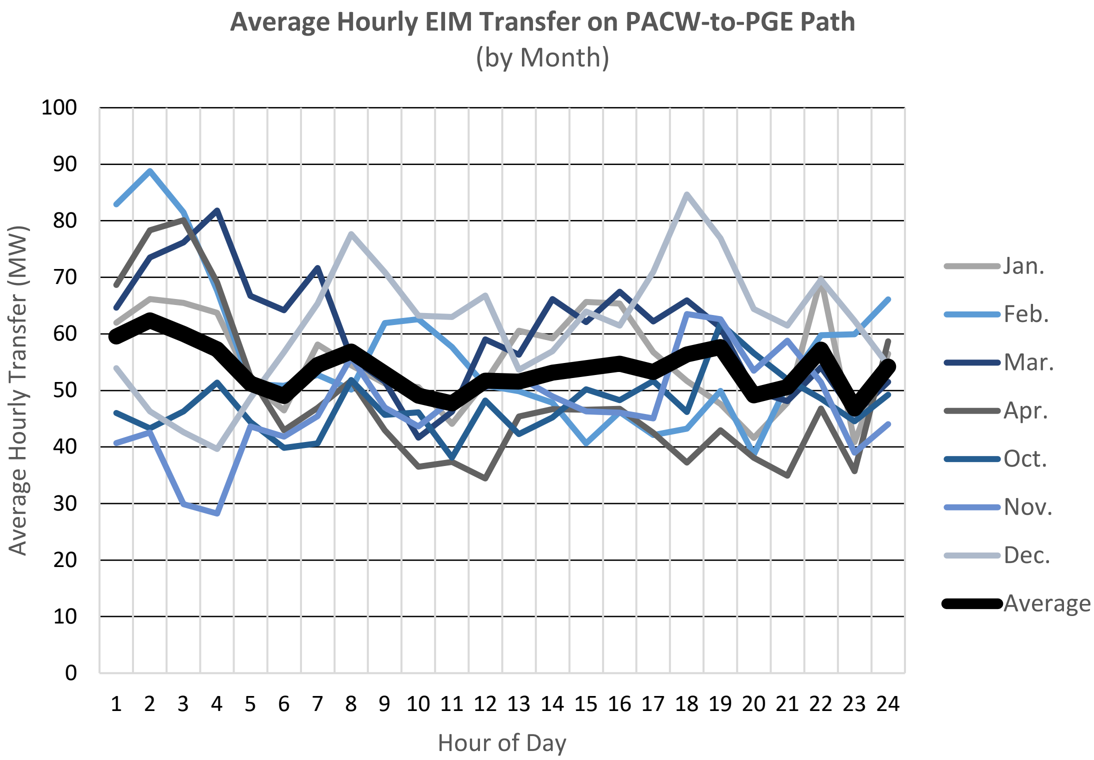
Q. PGE seems to imply that if they have anything less than 295 MW of dedicated rights, then there will be no transmission in the EIM. Do you agree?

A. No. Based on the ATC Methodology described above, there will be significant amounts of transmission in the EIM on the PACW-to-PGE import path if PGE were to reduce the amount of Interchange Rights Holder Methodology transmission on the path and dedicate more transmission using the ATC Methodology.

Q. Even if some transmission is used to deliver the output form the Blue Marmots, will much of PGE's EIM operations continue under status quo?

A. Generally, yes. Figure 2, below, shows when transfers have occurred, on an average hourly basis, on the PACW-to-PGE path since PGE joined the EIM, broken down by month.

Figure 2: Average Hourly EIM Transfers on PACW-to-PGE Path



PGE imports power on the path during all hours – not just during daytime conditions. In fact, its highest levels of imports occur during the very early morning hours between 1-4 am. Since the Blue Marmots will only be generating during daytime hours, and then even still at reduced levels for much of the time due to weather conditions, I expect that PGE EIM operations will continue much as they have to date and transmission available to the market will not change substantially. This, combined with the historically low utilization of the transfer path and the ATC Methodology benefits, there likely will be very little if any impacts to PGE's EIM benefits by it accepting the Blue Marmot output at the PACW-PGE interface.

IV. <u>REPLY TO TRANSMISSION TESTIMONY</u>

Q. Please summarize your general observations regarding PGE's Transmission Testimony.

A. PGE's Transmission Testimony describes the role of PGE Transmission, the PGE transmission system, and scheduling/reservation practices that PGE follows. I take few, if any, issues with these descriptions. PGE's detailed descriptions of all the processes and studies that it follows are generally correct, for better or worse. The complexity and awkwardness of certain studies and processes is one of the most important takeaways from PGE's Testimony: the limitations on PGE's system, as identified by the SIS and the TTC studies, are not traditional system reliability constraints that prevent PGE from importing additional power on the PACW-PGE interface because of thermal overloads or some other verifiable reliability issue. The limitations to import power on the PACW-PGE interface are actually methodological-constraints that are a product of the West's path-based approach to contracting and studying transmission (using FERC/NERC approved methodologies and procedures). This type of constraint would not happen in an organized market since transmission is, generally, used up to its reliability limit. This high-level takeaway sets appropriate context for the technical debate on the veracity of the studies.

Q. What other observations do you have regarding the PGE Transmission Testimony?

A. PGE's Transmission Testimony incorrectly describes the drivers behind the SIS that it performed for the Blue Marmots – I mentioned this concern earlier in my response to the Policy Testimony and will not revisit it at length here.[38] I also previously

[38] The TSRs were actually submitted by an affiliate of EDPR, but both parties are generally referring to the request as coming from the Blue Marmots. While the request was for 60 MW, the Blue Marmots are only pursuing 50 MW of capacity total.

covered my disagreement with how PGE describes the Blue Marmots' inability to schedule power into the PGE system. This topic comes up again in the Transmission Testimony and I will not restate my views.

My concerns specific to the Transmission Testimony are focused primarily on the technical aspects of the SIS itself. PGE says that there are reliability issues associated with accepting the Blue Marmot output. This is a methodology-derived outcome as I mention above, and it is not supported by actual power system stress, as my testimony will explain.[39] These concerns, among others, were uncovered through an independent study review. The complete report from that review is attached as Confidential Exhibit Blue Marmot/403. I include the most important findings from that effort here, but the full report is attached to document the methodology.[40]

Q. Please summarize the PGE SIS.

A. The SIS states that the 60 MW of requested PTP transmission is available in the winter season, but the study was needed to evaluate PGE's ability to increase the PACW-to-PGE path's transfer capability in the summer months because there was not sufficient ATC to grant the request. PGE's SIS concludes that the only way to deliver the Blue Marmots' output across the path is over a 300-mile gen-tie line that delivers the energy directly to PGE's Bethel 115-kV substation. The study considered one other transmission alternative to increase the TTC of the path, but it was determined that it could not increase the TTC to the requested 60 MW.

---

[39] In fact, the *non-existent* reliability implications of the Blue Marmots are the same regardless if they deliver via PACW-PGE or BPA-PGE. Neither is riskier than the other from an actual power flow perspective.

[40] The scope of this review also included a complete critique of the TTC and SIS study assumptions, the results of which is detailed in the attached summary report.

Based on the SIS, PGE's Transmission Testimony concludes that: 1) "there is no way to increase the TTC of the PACW-to-PGE path sufficiently to accommodate the Blue Marmots' delivery"; and 2) the Blue Marmots will need to "avoid the PACW-PGE interface entirely and could accomplish delivery directly by constructing a 300-mile generation lead line directly to PGE's system".

Q. Can you put the SIS and its results into context within this proceeding?

A. Yes. First, the SIS is only relevant if the Commission concludes that the Blue Marmots' output cannot not be accommodated by PGE within the existing capabilities of the PACW-to-PGE path *and* there are no other PURPA compliant means through which PGE can manage all or a portion of the Blue Marmot output. Second, the SIS is information that PGE can choose to use when determining the most economic means for it to manage the Blue Marmot power. Third, the SIS is only relevant for the summer season – there is sufficient ATC in the winter.

Q. Given this context and the benefit of the technical review you conducted for the Blue Marmots, what are your primary concerns with the SIS?

A. My concerns with the SIS are threefold. First, PGE did not consider a robust set of transmission alternatives in and around the PACW-PGE interface when evaluating options to increase TTC. Second, PGE's interpretation of certain study results is misleading. Third, the final solution offered by PGE is not realistic or reasonable. In the end, PGE's studies are flawed and PGE has not demonstrated that there are no other alternatives to accept the Blue Marmots' net output at the PACW-PGE interface.

Q. Before elaborating on your concerns, can you confirm that your firm maintains the requisite tools and skills to perform a robust technical review of the transmission studies?

A. Yes. We staff transmission planning engineers with experience designing and performing these studies. We also maintain the same powerflow modeling software that is used by PGE and performed our review and independent studies using the same study cases and assumptions that PGE used to perform the SIS and the PACW-PGE TTC Study.[41]

Q. Please summarize your observations surrounding the transmission alternatives that PGE considered.

A. PGE studied one upgrade to the PACW-PGE interface: a second 230-kV transmission line between the existing Bethel and Parish Gap substations. Our technical study confirmed PGE's assessment of this alternative, which was that its implementation could increase the TTC of the path by 19 MW. What seems to have been missed at this stage is that at the time there was 15 MW of ATC that was offered to the Blue Marmots (and later reserved by PGE after refusing to execute PPAs). If the Blue Marmots used this ATC, plus the 19 MW enabled by transmission alternative, it would have had 34 MW of capacity. Since the Blue Marmots were pursuing only 50 MW worth of projects (versus the 60 MW in the TSR), they would have only been 16 MW short *for half of the year*.[42] So, PGE somehow concluded that a new 300-mile line was the best and most efficient option solution for a seasonal 16 MW capacity shortfall.

Q. In your review, what additional transmission alternatives did you consider and what conclusions do you have surrounding the ability of those alternatives to increase the TTC of the PACW-PGE interface.

---

41 See Blue Marmots/401, Moyer/1-2 (PGE Response to Blue Marmot Data Request 119 in which PGE provided access to the models and data) (Confidential material not included in Exhibit).

42 While the TSR was for 60 MW, I understand that the Blue Marmots will only develop 50 MW.

A. Our studies used the same models, methodologies, and assumptions as PGE and we identified several transmission alternatives that PGE did not consider in its analysis. These alternatives are summarized in Table 2, along with the Bethel – Parish Gap 230 kV alternative that was considered by PGE (and re-evaluated in our assessment to confirm results and validate models).

Table 2: Summary of Transmission Alternatives for PACW-PGE Interface

Transmission Alternative (new facilities)	Maximum Reliable PGE-to-PACW Transfer (MW)	TTC Increase (MW)	Considered in PGE SIS Study?	Approximate Distance Between Substations (Miles)[43]
Bethel – Parish Gap 230-kV circuit	324 MWs	18 MW[44]	Yes	10.6
Marion – Bethel 500-kV circuit and 500/230 kV transformer at Bethel	381 MWs	75 MW	No	15.3
Ostrander – Bethel 500-kV circuit and 500/230 kV transformer at Bethel	374 MWs	68 MW	No	39.9
Santiam – Bethel 500-kV circuit and 500/230 kV transformer at Bethel	341 MWs	35 MW	No	17.3

We studied the three alternatives above in both 500-kV and 230-kV configurations. Both voltage configurations performed well, but the 500-kV configurations increased TTC the most and is presented in the table. These transmission alternatives, which increase flows on the PACW-PGE interface by increasing system connectivity to the high-voltage BPA system, need additional study work beyond the scope of our initial assessment. However, the purpose of our

---

43 These are direct-line miles and do not represent exact lengths required for line routing. At this screening stage, this is a reasonably method to identify feasible alternatives worthy of study.

44 Our independent analysis resulted in an 18 MW TTC increase compared to PGE's 19 MW TTC increase, which confirms that our models were properly calibrated and we were able to re-create the results that PGE generated.

assessment was to conduct a screening to find reasonably feasible alternatives that PGE should have considered and it revealed these options.

Q. Why did PGE not consider these alternatives?

A. The Blue Marmots asked PGE why they did not consider these alternatives or any other transmission configurations aside from Bethel – Parish Gap 230-kV.[45] PGE's response was that:

(1) Since the SIS was conducted pursuant to the terms of PGE's FERC-jurisdictional OATT, PGE has "sole discretion as to the scope, details and methods used to perform the study";

(2) PGE thought that the Blue Marmots "wished it to analyze redispatch options and the potential for upgrades to the Bethel-Parish Gap 230 kV line", so the limited to the scope to a single transmission solution;

(3) Based on PGE's engineering judgment, increasing the flow of power between Bethel and Parish Gap was the best option for increasing TTC that was most likely to be effective and constructible; and

(4) The proposed alternatives are "farther apart than Bethel and Parish Gap, and therefore it would be more expensive to construct a line between them".

PGE provides this justification for not evaluating these alternatives, but also recognizes that it anticipates they could increase the PACW-PGE interface TTC.[46]

Q. Do you think PGE's reasons for not considering these alternatives are reasonable?

---

45 Blue Marmot/401, Moyer/6-11 (PGE response to Blue Marmot Data Request Nos. 163-168).

46 Blue Marmot/401, Moyer/10 (PGE response to Blue Marmot Data Request No. 167).

A. No. Failing to consider alternatives in a study funded by the potential transmission customer does not seem prudent or reasonable. Also, PGE says they did not need to consider these upgrades because they have sole discretion over what to consider – another concerning and circular response when the company performing the study is party to this proceeding.

Additionally, PGE says that the Blue Marmots requested that PGE limit the study scope to certain solutions, but PGE was unable to produce any documentation to that effect and the Blue Marmots disagree.[47] The Blue Marmots did not request any such limitations in the study.

Lastly, based on our analysis, these substation pairs are close enough together to, at a minimum, warrant consideration alongside the one alternative PGE evaluated and certainly alongside the 300-mile solution. If cost effectiveness, performance, and constructability are the criterion, then these alternatives, which are all less than 40-miles apart, are much more feasible than the 300-mile solution. These factors lead me to conclude that PGE did not properly consider transmission alternatives.

Q. You state concerns with how PGE interpreted certain study results. What are the specific concerns?

A. On page 17 of the Transmission Testimony PGE says that the SIS indicates that "adding 60 MW of generation in the PACW BAA would result in a 30 MW *decrease* in TTC." This finding is erroneous given the MOD-029 methodology used to conduct

---

47 See Blue Marmots/401, Moyer/12 (PGE Response to Blue Marmot Data Request No. 171) ("PGE's understanding that EDPR wished it to analyze redispatch options and upgrades to the Bethel-Parish Gap 230 kV line was informed by the settlement discussion between EDPR and PGE, in which EDPR asked numerous questions regarding the Bethel substation, which is connected to PACW only via the Bethel-Parish Gap line.").

the study and it is important to rebut because PGE implies that the Blue Marmots will have detrimental impact on the path. That simply is not the case and it represents a fabricated interpretation of study results and methods.

Because of the unique flows on this path, the study methodology tried to maximize flows in the *export direction* (from PGE to PACW) to evaluate a transmission service request for additional *import* capability. This method is allowed under MOD-29 Rated System Path Methodology, which was established by FERC and enforced by NERC, and is one of many available methods to evaluate the transfer capacity of FERC-jurisdictional transmission. Using the study method, when PGE added a 60 MW generator on the PACW side of the PACW-PGE interface, flows from PGE to PACW decreased based on the laws of physics and PGE dispatch assumptions. Less power needed to flow from PGE to PACW because of the new injection. This change in flow is not a surprise and is not a study finding given the scope and purpose of the study, as stated by PGE, was to determine what transmission or redispatch options are available to increase the TTC. While the statement does not take center stage in the PGE testimony, it does confuse the record and should be disregarded.

Q. What other concerns do you have with PGE's interpretation of the study results?

A. PGE's Transmission Testimony makes mention that a system emergency could occur on PGE's transmission system if it were to accept the Blue Marmot output. I understand that PGE cannot accept schedules across its transmission system that are greater than a path's TTC – doing so would go against important operational and planning protocols that protect the reliability of the system. However, if we set these contract path-based issues aside and focus on the actual flow of power and actual stress on the system, very little of the Blue Marmot power actually reaches PGE's system and it does not cause system emergencies. Our power flow analysis suggests that when 60 MW is injected at the Blue Marmots' point-of-interconnection on the PacifiCorp system, only 3% of that injection actually reaches the PACW-PGE interface. This is because flows on the PACW-PGE path only change by 2 MW for every 60 MW of Blue Marmot power that is injected. From this perspective, the Blue Marmots' physical power flow has negligible negative impacts on PGE's transmission reliability because most of the physical power does not physically *reach* PGE's system and for that small amount of power that does (3%), it actually pushes back against the flow from PGE-to-PACW (reducing exports), so there is no increased reliability risk from a physical flow perspective (and since flows actually go down, you can argue that reliability is *enhanced)*. Note that this power flow condition is the same regardless if the Blue Marmots deliver to PGE via the PACW-PGE interface or the BPA-PGE interface.

Q. You also mentioned that the solution offered by PGE was not realistic or reasonable. Please expand on this.

A. PGE's ultimate solution in the SIS was for a 300-mile interconnection line to be constructed and owned by the Blue Marmots, directly connecting the Blue Marmots, located in southeast Oregon, with the PGE Bethel substation, which is near Salem, Oregon. This would require the transmission line, that would presumably need to be developed by the Blue Marmots, not PGE, to cross the Cascades mountain range and several federal National Forests. I estimate the total cost of the line on the order of $450,000,000 (excluding substation costs) – roughly $9,000,000 per MW of Blue

Marmot capacity and several times what the Blue Marmots will actually cost to build, by my estimate.[48] PGE is well versed in the challenge in permitting and funding transmission and this solution is clearly not feasible. PGE's findings are especially concerning given that it spent time and resources in a study, which was funded by the Blue Marmots, evaluating an infeasible solution versus studying the comparably more feasible transmission alternatives that I introduce above.

Q. PGE spends significant portions of the Transmission Testimony explaining the "MOD-029 Methodology" that is used to establish the TTC for the PACW-PGE interface. Please provide your observations surrounding the Rated System Path Methodology.

A. Although it is not readily obvious to a non-transmission planner, the study to determine the TTC of the path is performed in a counterintuitive manner. PGE's testimony explains why this is the case, which is that NERC MOD-29-2a sets the TTC for this path as the higher of the *simulated flow* across the path or the flow in the *prevailing direction.* Since the models cannot be adjusted to push power "uphill" from PACW into PGE (meaning actual flows in the model are always from PGE to PACW), the TTC for the PACW-to-PGE *import path* is set as the maximum transfer of the *export path* (PGE-to-PACW). Essentially, the PACW-to-PGE import path TTC is set by process default, not by an actual reliability limitation.

Q. How does this method of setting the import TTC impact the SIS?

A. This assumption carries over to the SIS performed by PGE. The SIS was performed to see what transmission solutions reliably increase flow *from* PGE *to* PACW – the exact opposite direction from which the contractual capacity is actually needed to

---

48 Calculated using the TEPPC Transmission Capital Cost Calculator available here: (https://www.wecc.biz/Reliability/2014_TEPPC_TransCapCostCalculator.xlsx)

accommodate the Blue Marmot output. Thus, the transmission alternatives I describe above are designed to increase flows *out of PGE's system* even though that is the opposite direction in which the system is contractually constrained and where new capacity is needed. In my view, this results in a wasteful (and admittedly, confusing) planning approach where technical planning requirements and contract path approach to managing transmission have the potential to drive unneeded and potentially costly transmission investment.

Q. Is this type of planning performed in deregulated energy markets?

A. Generally, no. Most Independent System Operators and Regional Transmission Organizations do not plan their system using contract paths or MOD-29. Generally speaking, they have more efficient flow-based means of managing transmission in the market and expanding transmission based on economic and reliability needs, managing transmission requests based on the physical effects a power transfer has relative to the technical capabilities of the system. For example, Locational Marginal Pricing ("LMP") and congestion prices will indicate where the system is constrained based on actual flows and dispatch, and so long as a transmission service request does not cause an actual reliability issue it can be granted (and the capabilities of the system maximized up to safe operating limits). If PGE was operating in such a market, I doubt the PACW-PGE import path would need to be upgraded to accept delivery from the Blue Marmots.

PGE, along with the rest of the Western Interconnection, are in an awkward position with one-foot in real-time energy markets (where congestion, LMPs, real-time dispatch rule the day) and the other foot planning a transmission system based on contract paths and antiquated path-based determinations of what the system can handle. This makes the thoughtful management of *existing* transmission system capacity even more critical. Given that there are no real-world reliability issues and very little of Blue Marmots' power actually reaches PGE's system because of real world power flows, a prudent and reasonable utility should not conclude that a 300-mile gen-tie line is the best way to accept power.

V. SUMMARY

Q. Please summarize your testimony.

A. My testimony focuses on two primary themes. First, the Blue Marmots have made the appropriate transmission arrangements and PGE should be required to counter-sign the Blue Marmots' PPAs and accept the output at the PACW-PGE interface. Second, PGE has ample cost-effective options to manage and accept the Blue Marmot output, and I am skeptical of certain concerns and costs purported by PGE. PGE has not performed a sufficiently robust and technically accurate inventory of the options it has, and for those options that PGE has considered, PGE has inflated their costs, or perceived costs, through technically questionable analysis or unsubstantiated statements. In addition to those identified in my Direct Testimony, some examples that support this conclusion include:

(1) PGE's inability to balance its desire to add to its EIM capacity against its QF obligations under PURPA. It has also failed to present a policy summarizing how this balance is struck. Thereby, absent this policy, we must assume the option of adding transmission and directing it to the Blue Marmots has not been considered.

(2) PGE could seek to use certain amounts of its EIM-dedicated transmission to accommodate the Blue Marmots' output. PGE's arguments against this fall

flat – the PACW-to-PGE import path is not well utilized in the EIM and ultimately the Blue Marmot power will not substantially affect the amount of transmission that PGE requires on the path to have beneficial EIM imports. Additionally, absent any factual analysis or evidence, it is unclear what, if any, portion of PGE's benefits are tied to its MBR authority. To the extent PGE loses this authority or must seek to reclaim it from FERC as a result of accepting the Blue Marmot output, that cost should be assumed to be zero until we know otherwise.

(3) PGE did not perform a reasonable SIS for the Blue Marmots – expanding the transmission capacity was another option to accept the output. While new transmission may not be the most efficient means for PGE to manage the Blue Marmots' power, the option to do so was never truly on the table as PGE did not consider a reasonable slate of transmission alternatives, and the one it did focus on is 300-miles long and technically infeasible.

PGE's consideration of options to accept the Blue Marmots' power has been incomplete and does not support its refusal to counter-sign the PPAs.

Q. Do you have any recommendations for the Commission regarding PGE's obligation to manage the Blue Marmots' output?

A. Yes. First, the Commission should not allow PGE to dismiss its PURPA QF obligations on a one-off basis. It is true that QF power will have different value to the utility depending on its location and/or its delivery point. However, PGE's avoided cost rates do not consider these locational-specific issues. Thus, PGE's purported concerns and costs should only be addressed on a forward-looking basis. Proactive, rather than retroactive, revisions to QF policy are an important aspect of appropriately encouraging QF development.

Second, PGE has many options to accept and manage the Blue Marmot power, as I have outlined in my testimony. If PGE is required by this Commission to counter-sign the Blue Marmot PPAs and accept delivery of their output at the PACW-PGE interface (or otherwise mange the energy), PGE is the entity best positioned to conduct the analysis to determine which option will be most cost effective. That option could entail changes to its EIM participation, selling all or portions of the power to other utilities, or expanding the transmission capability at the PACW-PGE interface. No doubt there are other options, and PGE is the entity best suited to select among them so long as its QF obligations to the Blue Marmots are upheld.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829)	)
BLUE MARMOT VI LLC (UM 1830)	)
BLUE MARMOT VII LLC (UM 1831)	)
BLUE MARMOT VIII LLC (UM 1832)	)
BLUE MARMOT IX LLC (UM 1833)	)
Complainants	)
vs.	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
Defendant	)
Pursuant to ORS 756.500.	)
	)

EXHIBIT BLUE MARMOT/401

PGE DATA RESPONSES

June 18, 2018

February 7, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 119
Dated January 24, 2018

Request:

119. Please provide the power flow simulation cases used to conduct the System Impact Study along with the study cases used to evaluate TTC on the PGE-to-PACW path and the PACW-to-PGE path.

a. Please include study cases that were used to determine and evaluate the Proposed Plan of Service and any other alternative Proposed Plans of Service considered by PGE for the System Impact Study.

b. Please include contingency lists and associated data for all cases used in the study.

c. Please include data for any modeled for Remedial Action Schemes or Special Protection Schemes.

d. Please provide this information to Blue Marmots consultant, Energy Strategies, LLC of Salt Lake City, Utah.

e. Blue Marmot understands that this information is CEII and must be protected and the Blue Marmots and its consultant have executed the appropriate Non-Disclosure Agreements detailed in PGE's Business Practice "Processing Requests for Critical Energy Infrastructure Information"

Response:

a. The case used to conduct the System Impact Study is 19 HS Planning.pwb. The case reflecting the result of the most recent TTC study is 18 HS Planning 320 MW Final Case.PWB. Both the 18 and 19 HS Planning cases were developed and thoroughly vetted by PGE for its own planning purposes. The cases are based on WECC base cases and were refined by PGE to scale loads to the most recent known values and to update for other known system changes arising after the cases were developed.

For the TTC study, the 18 HS Planning case was modified as described in the study, which will be provided as Confidential Attachment 119-A.[1] The 18 HS Planning 320 MW Final Case provided in response to this data request includes all system adjustments that were made to achieve the 320 MW TTC.

For the System Impact Study, PGE modified the 19 HS Planning case as described in the System Impact Study to include modeling of all study assumptions, including firm transfers, in order to evaluate potential impacts of the Plan of Service on the parallel transfer paths.

b. Because PGE used the PowerWorld software program to complete the TTC study and System Impact Study, the case files listed above include the contingency lists and all associated data used in the studies. (In PowerWorld, the contingency lists and other data are not contained in separate files as they would be for other software programs.)

c. No Remedial Action Schemes were used in the TTC study or the System Impact Study. NERC no longer recognizes the term Special Protection Scheme. Special Protection Schemes have been absorbed under the term Remedial Action Schemes. However, no Special Protection Schemes (as the term formerly was used) were used in the TTC study or the System Impact Study.

d. As requested, the cases will be transmitted directly to the Energy Strategies, LLC employees who have signed a CEII Agreement (Keegan Moyer and Gary Simonson).

[1] The 2017 TTC Study was a joint study between PGE and PacifiCorp. Because the Report contains both utilities' Confidential Energy Infrastructure Information (CEII), PGE is working with PacifiCorp to obtain approval to release the information to EDPR and will provide the Report as soon as PGE obtains approval to do so.

February 9, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 134
Dated January 26, 2018

Request:

134. On GREEN-MOORE/17: 6-9, PGE asserts that "because there is no ATC on the PACW to PGE path, the generation cannot travel from the PACW.PGE POD on PacifiCorp's side of the interface to PGE's side of the interface, which is technically the Point of Receipt (POR)."

a. Please explain who provides transmission service across this interface between the PacifiCorp POD and the PGE POR, and how such service is managed under PGE's OATT.

b. Please provide factual documentation, including references to NERC Standards, NERC Glossary of Terms, FERC Orders, NAESB Business Practices, PGE Business Practices, and/or other references, that detail how transmission service across the "interface" is obtained, and why it is managed by PGE (versus PacifiCorp).

Response:

a) PGE objects that the predicate of this question is incorrect. Without waiving its objection, PGE responds as follows: There is no "transmission service across the interface." Please see PGE's Response to Data Request No. 133 for a description of the PACW-PGE interface. Pursuant to their respective OATTs, PGE and PacifiCorp provide transmission service on their respective paths on either side of the interface. In order for a transaction to pass through the interface, transmission capacity must be available on both systems for the transaction to be scheduled on both PACW's and PGE's paths. Because the interface is not a sink, a transaction may not terminate there. *See* definitions of "Interchange Transaction," "Point of Delivery," and "Point of Receipt" in the NERC Glossary of Terms (making clear that an Interchange Transaction (i.e. an agreement to transfer energy across BAA boundaries) *leaves* one transmission system through a Point of Delivery on that transmission system and *enters* an adjacent transmission system through a Point of Receipt on the adjacent transmission system).

b) PGE objects that the predicate of this question is incorrect. Without waiving its objection, PGE responds as follows: There is no "transmission service across the interface." Please see PGE's Response to Data Request No. 134(a).

UM 1829
PGE Response to Blue Marmot's Twelfth Set of Data Requests

February 16, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 159
Dated February 2, 2018

Request:

159. Please provide all workpapers and supporting documentation used to create Table 1.

Response:

Attachment 159-A is the workpaper used to create Table 1. The values listed in Table 1 can be found in the worksheets titled "Dec_PACW", "Nov_PACW", and "Oct_PACW".

March 27, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 163
Dated March 13, 2018

Request:

163. When Portland General Electric Transmission ("PGET") performed the System Impact Study for PTP-70, did it consider any of the following transmission alternatives to increase the TTC of the PGE-PACW interface (or "PGE.PACW interface" in the study):

a. Bethel – Marion 230 kV: A new 230 kV transmission line from the existing PGE Bethel substation to a new Marion 230 kV substation connected to the existing BPA 500 kV Marion substation via a new 230/500 kV transformer;
b. Bethel – Ostrander 230 kV: A new 230 kV transmission line from the existing PGE Bethel substation to a new Ostrander 230 kV substation connected to the existing BPA 500 kV Ostrander substation via a new 230/500 kV transformer;
c. Bethel – Santiam 230 kV: A new 230 kV transmission line from the existing PGE Bethel substation to a new Santiam 230 kV substation connected to the existing Santiam BPA 500 kV substation via a new 230/500 kV transformer.
d. Bethel – Marion 500 kV: A new 500 kV transmission line from the existing BPA Marion 500 kV substation to a new 500 kV PGE Bethel substation connected to the existing 230 kV Bethel substation via a new 230/500 kV transformer.
e. Any transmission configurations not listed above, excluding the Bethel – Parish Gap 230 kV line alternative included in the study.

Response:

No. The alternatives listed in a-e above were outside the scope of PGE's System Impact Study for the reasons discussed in response to Data Request No. 164.

March 27, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 164
Dated March 13, 2018

Request:

164. If PGET did not consider or study the transmission alternatives identified in data request 163(a)-(d), above, please explain why not and please provide reference to appropriate FERC or NERC guidance that prevented PGET from studying these alternatives.

Response:

As explained in PGE/100, Greene-Moore/19, PGE conducted the System Impact Study (SIS) for EDPR as a part of the settlement discussions arising from this complaint proceeding (UM 1829). As explained in PGE/300, Afranji-Larson-Richard/16, the SIS was conducted in accordance with PGE's OATT. Attachment D to PGE's OATT contains the Methodology for Completing a System Impact Study. It provides that the SIS procedure will use "Good Utility Practice and the engineering and operating principles, standards, guidelines, and criteria of PGE, the WECC, NERC, or any similar organization that may exist in the future of which PGE is then a member." It also states that, "PGE shall use its sole discretion as to the scope, details and methods used to perform the Study."

The scope of the EDPR SIS was informed by PGE's understanding that EDPR wished it to analyze redispatch options and the potential for upgrades to the Bethel-Parish Gap 230 kV line. In addition, based on its engineering judgment, PGE believed that increasing the flow of power between Bethel and Parish Gap was the option for increasing TTC that was most likely to be effective and able to be constructed.

PGE did not consider options for increasing the flow between other substation pairs—such as those listed in Data Request No. 163—because they are farther apart than Bethel and Parish Gap, and therefore it would be more expensive to construct a line between them—certainly more expensive than the alternative of moving the Blue Marmots' output to the BPA interface.

March 27, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 165
Dated March 13, 2018

Request:

165. If PGET did consider the transmission alternatives identified in data request 163(a)-(d), or any other solutions listed in the response (e), please explain why they were not included in the PTP-70 System Impact Study report.

Response:

PGE did not consider the listed alternatives for the reasons explained in response to Data Request No. 164.

March 27, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 166
Dated March 13, 2018

Request:

166. Since the completion of the PTP-70 System Impact Study, has PGET studied the transmission alternatives identified in data request 163 (a)-(d), above?

Response:

No. PGE has not performed a study of those transmission alternatives, nor does PGE believe any such study would result in a viable solution. Based on PGE's engineering judgment and understanding of transmission planning fundamentals, the suggested alternatives would be prohibitively expensive and/or extremely difficult to permit and construct.

March 27, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 167
Dated March 13, 2018

Request:

167. Does PGE agree that the addition of the individual transmission alternatives identified in data request 163 (a)-(d) to the Benchmark Cases used to conduct the System Impact Study result in observable and measurable increases to flows on the PACW-PGE interface between 25-75 MW depending on conductor type, configuration, and line voltage?

a. If no, please explain why PGE does not agree that increased flow on the interface occurs.

Response:

PGE objects that it has not conducted the analysis necessary to respond to this request and that conducting such analysis would be time-consuming and burdensome. Without waiving its objections, PGE responds that it anticipates the alternatives listed in Data Request No. 163a-d could increase the PACW-PGE interface flow. However, PGE believes that these alternatives would be prohibitively expensive and/or extremely difficult to permit and construct.

March 27, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 168
Dated March 13, 2018

<u>Request:</u>

168. Does PGE agree that the transmission alternatives identified in data request 163(a), (b), and (c) above would increase the TTC of the PACW-PGE interface by 25-75 MW?

a. If no, please explain why PGE does not agree the TTC would increase.

<u>Response:</u>

PGE objects that it has not conducted the analysis necessary to respond to this request and that conducting the analysis would be time-consuming and burdensome. Without waiving its objections, PGE responds as follows: Please see PGE's response to Data Request No. 167.

In addition, please note that the existing methodology for studying the BPA and PACW transfer paths assumes that the two paths load independently of each other. For that reason, it currently is not necessary to study both paths' loadings simultaneously. However, constructing a new source into the PGE system from BPA, which would result in a significant impact to the PACW path, would require a review of the existing methodology to confirm the paths would still load independently of each other. If this were no longer true, the paths would have to be studied simultaneously. PGE does not know what impact a simultaneous study would have on each path, but it is likely that to maximize the flow on one path, the flow on the other path would not be maximized. This interplay between the two paths could decrease the PACW TTC.

April 19, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 171
Dated April 5, 2018

Request:

171. In response to Data Request No. 164, PGE states that the scope of the Blue Marmots' System Impact Study (SIS) was "informed by PGE's understanding that the Blue Marmots wished it to analyze redispatch options and the potential for upgrades to the Bethel-Parish Gap 230 kV line."

a. Please provide documents, emails, or other records that support PGE's position that the Blue Marmots requested that PGE limit the scope of the SIS to upgrades on the Bethel-Parish Gap 230 kV line.

Response:

PGE objects on the basis that this request misstates PGE's response to Data Request No. 164. PGE did not state that the Blue Marmots requested PGE to limit the scope of the SIS to upgrades on the Bethel-Parish Gap 230 kV line. Rather, PGE stated that the scope of an SIS is within PGE's sole discretion, and here, the scope was "informed by PGE's understanding that EDPR wished it to analyze redispatch options and the potential for upgrades to the Bethel-Parish Gap 230 kV line. In addition, based on its engineering judgment, PGE believed that increasing the flow of power between Bethel and Parish Gap was the option for increasing TTC that was most likely to be effective and able to be constructed." PGE went on to explain that it did not consider other substation pairs, "because they are farther apart than Bethel and Parish Gap, and therefore it would be more expensive to construct a line between them."

Notwithstanding its objections, PGE responds as follows: PGE's understanding that EDPR wished it to analyze redispatch options and upgrades to the Bethel-Parish Gap 230 kV line was informed by the settlement discussion between EDPR and PGE, in which EDPR asked numerous questions regarding the Bethel substation, which is connected to PACW only via the Bethel-Parish Gap line. In addition, as PGE explained in its response to Data Request No. 164, PGE's focus on the potential Bethel-Parish Gap upgrades was based on PGE's engineering judgment.

June 4, 2018

TO: Irion Sanger
Leslie Freiman
Will Talbott

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1829
PGE Response to Blue Marmot Data Request No. 176
Dated May 22, 2018

Request:

176. PGE's EIM Testimony summarizes the ATC and Interchange Rights Holder approach to EIM participation. PGE indicates that it uses a hybrid approach.

- **a. When PGE participates using the ATC methodology, what ATC algorithm (firm, non-firm) and what timing period (e.g., scheduling, operating) is used to determine the amount of transmission capacity that is included in the EIM 5- and 15-minute markets?**
- **b. How are counterflows and postbacks handled when calculating these ATC values for EIM purposes?**
- **c. Is this EIM ATC data available on OASIS? If so, how can it be located.**

Response:

a. PGE does not calculate ATC values for EIM purposes. Instead, PGE calculates EIM transfer capability using what is commonly referred to as the "ATC Methodology," as well as the Interchange Rights Holder Methodology, and PGE provides the EIM transfer capability to CAISO.

To be clear, the "ATC Methodology" used to calculate EIM transfer capability is distinct from the methodology to assess ATC, as described in PGE's OATT Attachment C or in the ATC Implementation Documents contained on PGE's OASIS homepage, which is used to calculate ATC on PGE's transmission paths. The calculation of EIM transfer capability does not use ATC Algorithms or timing periods, as defined in the ATC Implementation Documents on PGE's OASIS.

The EIM transfer capability calculation methodology is described in PGE's OATT, Attachment P, Section 5.3, entitled Provision of EIM Transfer Capability by the PGE EIM Entity. PGE determines EIM transfer capability using the following formula:

EIM Transfer Capability = Path TTC - Implemented Interchange Schedules on the associated path + Counter Schedules of the opposite path

PGE calculates EIM transfer capability for the current and next operating day anytime there is an update to the Path TTC. The limit submitted to CAISO is used for both the 15-minute and the 5-minute markets.

b. As explained above in part a, PGE does not calculate ATC values for EIM purposes. Instead, it calculates EIM transfer capability using the formula described in part a. In this formula, counter schedules of the opposite path (which are based on NERC e-tags and not on actual physical counterflows) will increase the transfer capability of the associated path. Postbacks, as defined in PGE's ATC Implementation Documents, are not used in the determination of EIM transfer capability.

c. As explained above in part a, PGE does not calculate ATC values for EIM purposes. Instead, it calculates EIM transfer capability. EIM transfer capability data are not available on PGE's OASIS. EIM transfer capability data are available on the CAISO OASIS (http://oasis.caiso.com) using the "EIM Transfer Limits by Tie" option under the "Energy" dropdown menu. PGE notes that these data represent the total EIM transfer capability that results from both the Interchange Rights Holder and ATC Methodologies.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829)	)
BLUE MARMOT VI LLC (UM 1830)	)
BLUE MARMOT VII LLC (UM 1831)	)
BLUE MARMOT VIII LLC (UM 1832)	)
BLUE MARMOT IX LLC (UM 1833)	)
Complainants	)
vs.	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
Defendant	)
Pursuant to ORS 756.500.	)
	)

EXHIBIT BLUE MARMOT/402

CALIFORNIA ISO MEMORANDUM
DECISION ON COMMITMENT COSTS AND
DEFAULT ENERGY BID ENHANCEMENTS PROPOSAL

June 18, 2018

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: March 14, 2018

Re: **Decision on commitment costs and default energy bid enhancements proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management proposes to modify the ISO's rules for submitting supply offers to allow suppliers to more accurately reflect their costs in the ISO market. The modifications will provide increased flexibility for suppliers to bid in their actual costs, along with safeguards to mitigate market power under uncompetitive conditions. Some of these rule changes are also needed to comply with Federal Energy Regulatory Commission (FERC) Order No. 831.

The ISO market design allows resources to submit separate bid components for their market bid for energy above minimum load, minimum load costs, start-up costs and, for multi-stage resources, their transitions from one configuration to another. Minimum load, start-up, and transition costs are collectively referred to as "commitment costs."

Under the current design, the ISO calculates daily "reference levels" for each natural gas generator that are based on published natural gas price indices. Commitment cost bids are capped at reference levels determined by 125 percent of the ISO-calculated costs. The ISO sets reference levels for energy above minimum load at 110 percent of its calculation of each resource's costs. These energy reference levels are referred to as "default energy bids."

Unlike energy bids, which the ISO market only limits to a resource's default energy bid if it detects local market power, commitment cost bids are always capped at the resource's reference level, even under competitive conditions. The California ISO is the only ISO in the United States to do this. Other ISOs only limit commitment cost bids to reference levels if market power is detected.

Suppliers have raised concerns that the current commitment cost bid cap does not always allow suppliers to reflect their actual or expected costs. The gas price indices used to calculate reference levels may not reflect the wide variety of generators throughout the ISO balancing area and the broader Energy Imbalance Market footprint, and may not reflect volatile or illiquid gas markets. This existing cap can undermine market efficiency and discourage participation in the market. Additionally, the existing daily minimum load bid construct prevents resources from reflecting minimum load costs that vary throughout the day.

Management proposes to enhance suppliers' ability to reflect commitment costs by replacing the static commitment cost bid cap with a dynamic commitment cost local market power mitigation test. The ISO will run the test in the market systems and will mitigate commitment cost bids prior to executing the applicable market run if a resource is needed to relieve a transmission overload. Management also proposes a "circuit-breaker" commitment cost bid cap to protect against test failures.

Management's proposal also includes enhancements that enable suppliers to request adjustments to both commitment cost and energy reference levels before the ISO market runs. Verified cost adjustments would then be used in the ISO market runs. In the event the costs could not be verified prior to the market run, Management proposes that the market participant be given the opportunity for an after-the-fact recovery of actual costs that could not be verified before the market ran. The proposal also changes minimum load bids from daily to hourly.

Management presented this proposal to the Energy Imbalance Market governing body on March 8, and the Governing Body voted to provide advisory input to the ISO Board of Governors supporting this proposal.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the proposal to implement the commitment costs and default energy bid enhancements described in the memorandum dated March 14, 2018; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the commitment costs and default energy bid enhancements described in the memorandum dated March 14, 2018, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Federal Energy Regulatory Commission guidance in any initial ruling on the proposed tariff amendment.***

DISCUSSION AND PROPOSAL

The following sections first provide related background information describing the ISO existing supply bidding related market rules and FERC's Order No. 831, and then describe Management's proposal to enhance suppliers' ability to reflect and recover costs in the ISO market.

Background

The ISO market design allows resources to submit separate bid components for their market bid for energy above minimum load, minimum load costs, start-up costs and, for multi-stage resources, their transitions from one configuration to another. Minimum load, start-up, and transition costs are collectively referred to as "commitment costs."

The ISO calculates daily reference levels for each natural gas generator that are based on published natural gas price indices.[1] The ISO sets commitment cost reference levels at 125 percent of its calculation of each resource's costs. The ISO sets reference levels for energy above minimum load at 110 percent of its calculation of each resource's costs. These energy reference levels are referred to as "default energy bids."

The ISO market uses the energy reference levels as part of its local market power mitigation measures for energy bids. The market replaces a resource's energy bid with its default energy bid if the resource fails a test that detects if the resource has market power in setting energy locational marginal prices. Otherwise, the market rules only limit energy bids to a $1,000/MWh "circuit-breaker" cap.

In contrast, commitment cost bids are always limited by a static bid cap set at the ISO's daily calculation of 125 percent of a resource's costs.[2] The California ISO is the only ISO or RTO in the United States to do this. Other ISOs and RTOs only limit commitment cost bids to reference levels if market power is detected. Specifically, PJM uses a three-pivotal supplier test to detect local market power, which is similar to the California ISO's energy local market power test, and only limits commitment costs if a resource fails the test. Alternatively, NYISO, MISO, SPP, and ISO-NE use a conduct and impact market power test for commitment costs, and only potentially limit commitment costs if a supplier's bids (i.e. its "conduct") are above a certain cost threshold.

A temporary tariff provision adopted to address the limited use of the Aliso Canyon storage facility provides for the ISO to calculate reference levels for the day-ahead market based on natural gas price index information published by the Intercontinental Exchanges (ICE) based on "next-day" gas trading occurring on the morning of the day-ahead market. The ISO

[1] The ISO calculates reference levels for other supply resources based on costs suppliers submit to the ISO's master file.

[2] Use limited resources are currently allowed to use the "registered cost" option for commitment costs that fixes a resource's commitment cost up to 150% of projected costs for 30 days. Changes approved by the Board of Governors in March 2016 will limit the registered cost option to new use-limited resources that do not have one year of locational marginal price data to calculate an opportunity cost adder.

calculates reference levels for the real-time market based on gas price indices published the evening before the day of the real-time market, which are based on next-day gas trading.

These gas price indices used for the day-ahead market and real-time market may not reflect actual costs, particularly for the real-time market, because "same-day" gas prices can be significantly different than the next-day gas prices that occurred on the prior day. These gas price indices may also not reflect individual generators' costs throughout the ISO balancing area and the broader western energy imbalance market footprint that may be located away from the gas trading hubs on which the indices are based.

Resources are also limited in accurately reflecting commitment costs because minimum load bids are currently daily values in which suppliers can only submit a single hourly minimum load cost for the entire day. Although suppliers can update this cost for the remainder of the day in the real-time market, not allowing minimum load cost bids to vary by hour prevents either the day-ahead or real-time markets to consider costs that may vary hourly.

In summary, the ISO's existing commitment cost bidding rules based on a static commitment cost bid cap can inappropriately limit resources from reflecting their actual costs. It is especially important for suppliers to be able to reflect accurate commitment costs so that the ISO market efficiently commits the right set of resources. Similarly, the ISO's existing calculation of default energy bids may not accurately reflect individual resources' actual costs to produce energy.

Management's proposal also addresses compliance with FERC's Order No. 831. This order requires allowing energy supply bids that can set market prices of up to $2,000/MWh if the bid is based on verifiable actual costs. Bids for virtual supply or imports do not have to demonstrate actual costs. The order states that energy supply bids above $1,000/MWh that are subject to cost verification can only set market prices if the ISO can verify the costs prior to the market run. Otherwise, the resource is eligible for an uplift payment if the ISO verifies the costs after-the-fact.

Proposed changes

Management proposes to modify the ISO's rules for submitting supply offers to allow suppliers to accurately reflect and recover their costs in the ISO market. These rule changes include safeguards against market power and are described in the following sections.

Replace static commitment cost cap with "market-based" commitment cost bids and commitment cost local market power mitigation test

Management proposes to replace the static commitment cost bid cap set at each resource's reference level with rules that will allow suppliers to submit "market-based" commitment cost bids. The market would only mitigate these bids to a resource's commitment cost reference level if a test in the market detects the resource has commitment cost local market power. Otherwise, these “market-based” bids will only be limited by a circuit-breaker commitment cost bid cap. Management also proposes related rule changes to protect against inflated commitment costs when the market must keep a resource on because of inter-temporal constraints or other market conditions.

There are two situations under which the proposed commitment cost market power mitigation test will mitigate commitment costs. First, the test will mitigate commitment costs when a resource can relieve a non-competitive constraint that is “binding” in the market, for example, when flows on a transmission line are at the line’s capacity.[3] Second, the test will mitigate commitment costs of any committed resource the market could have potentially committed to relieve the constraint. This second situation is necessary because the market may commit a resource based on its minimum load and then the constraint the market committed it to relieve becomes not binding. These are the resources that potentially have commitment cost market power because the market may have committed them to unload the constraint.

Management proposes to limit market-based commitment cost bids to a circuit-breaker bid cap to guard against potential situations not accounted for by the commitment cost local market power mitigation test and related rules. Management proposes to phase-in commitment cost bidding flexibility to ensure the commitment cost local market power mitigation test and related rules are functioning appropriately when first implemented. Management proposes to set the circuit breaker commitment cost bid cap for the first 18 months at 150 percent of each resource’s commitment cost reference level. After this period, the cap will increase to 300 percent of each resource’s commitment cost reference level. Management proposes 300 percent because it provides a reasonable range based on historical gas-price volatility to capture costs the vast majority of the time and because it is similar to the bid amounts subject to mitigation under other ISO’s conduct and impact test commitment cost market power mitigation methodologies.

Similarly, management proposes to phase-in the level to which the market will mitigate commitment costs in the event a resource fails the commitment cost market power test. For the first 18 months, Management proposes to mitigate the commitment costs of resources that fail the commitment cost market power test to 125 percent of ISO-calculated costs, which is similar to the current static commitment cost bid cap. This is so that suppliers will not be subject to a more restricted ability to reflect costs than under the existing rules in the event the new commitment cost local market power mitigation test inaccurately detects market power when in fact it does not exist. After 18 months, the market will mitigate commitment costs of resources that fail the commitment cost market power mitigation test to 110 percent of ISO-calculated costs. This value is calculated similarly to a default energy bid, which is also 110 percent of ISO-calculated costs.

[3] It will also mitigate the commitment cost of any resource needed to meet a minimum online constraint. These constraints commit a minimum amount of capacity within a limited area and generally do not entail competitive conditions.

The phased-in approach provides protection against potential false positives and false negatives of the dynamic commitment cost market power mitigation. In the event the ISO determines the market power mitigation is not functioning as designed, we will correct the mitigation or file with FERC to extend the period of the interim bid caps.

Management proposes related rules to disallow changes to minimum load bids when the market must keep a resource or multi-stage generator configuration on or off because of an exceptional dispatch instruction. Similar to the existing energy settlement rules for exceptional dispatches, these rules would apply to exceptional dispatches needed to relieve constraints deemed uncompetitive ahead of time based on historical pivotal supplier test results. Similar rules will apply when the market cannot shut a resource down until it ramps it to its minimum load.

Allow market participants to request adjustments to their energy and commitment cost reference levels

As described earlier, in the operational timeframe, a resource's actual costs may differ from the ISO-calculated costs used to determine a resource's energy or commitment cost reference level. Management proposes to allow suppliers to request an adjustment to a resource's reference level if its documented costs exceed the costs the ISO used to calculate the reference level.

Management proposes to screen energy and commitment cost bids reference level adjustment requests using an automated "reasonableness threshold." The market will automatically accept reference level adjustment requests that fall within the reasonableness threshold. Otherwise, it will cap the adjustment at the reasonableness threshold. An exception will be for energy bid costs above $1,000/MWh as required by FERC Order No. 831, which mandates that the ISO verify incremental energy offers above the $1000/MWh cap are cost-based and accurately reflect their actual or expected short-run marginal cost prior to the market run. Consistent with this requirement, time permitting, the ISO will review manually the resource's costs that exceed the energy before the market runs, if the supplier submits the appropriate evidence in a timely manner. Management does not propose to extend this same manual verification opportunity to the commitment costs because it would be virtually impossible to verify these costs before the market run given that they are based on more complex factors other than the cost of fuel, which is the main driver for incremental energy costs and more easily verifiable. In any case, as discussed below, Management proposes that suppliers have the opportunity to demonstrate their costs incurred after the market run if they exceed the thresholds and could not be verified before the market run.

Management proposes that the reasonableness threshold be the result of a daily resource-specific calculation that adds a fixed percentage to the fuel cost component of a resource's reference level calculation. For natural-gas-fired resources, Management proposes to calculate the reasonableness threshold by scaling the gas price used in the reference level calculation by 125 percent on Mondays or days after holidays, which are subject to increased price volatility due to the lag between the trading and operational days, and by 110 percent on other days. Management proposes to scale the fuel or fuel-equivalent costs of other resources by 110 percent.

Management selected these scaling percentages to capture most of the difference between actual gas purchases and the published indexes. The reasonableness threshold calculation for Mondays and days after holidays scales gas price by a higher percentage because the practices for purchasing gas over the weekend and for Monday, and trading conditions involving holidays, frequently cause the actual gas purchase price to exceed the published index.

Management proposes that the ISO have the ability to modify the standard reasonableness threshold calculation of individual resources to reflect particular differences between these resources' costs and the costs used to calculate their reference levels. As described below, Management's proposal includes provisions for suppliers to seek after-the-fact cost recovery for actual costs incurred but for which the supplier submitted a reference level adjustment that was limited by the reasonableness threshold. The ISO would modify the standard reasonableness threshold calculation for an individual resource if repeated after-the-fact cost recovery requests showed the standard calculation did not reflect the resource's costs.

Management proposes to require that suppliers base reference level adjustment requests on actual price quotes. The ISO will have the authority to audit these requests even if they fall within the thresholds and there will be provisions to suspend the ability of a supplier to request reference level adjustments, and to potentially refer the supplier to FERC for submitting false information, if its requests cannot be backed up with actual price quotes.

Allow market participants to seek after-the-fact cost recovery for actual incurred costs for which the ISO approved a reference level adjustment request before the market ran

Management proposes to allow suppliers to request after-the-fact that the ISO review a reference level adjustment request that was limited by the reasonableness threshold and not incorporated into the market. Verified actual costs would be eligible for after-the-fact recovery through a bid cost recovery uplift payment. To comply with FERC Order No. 831, this will include energy costs above the $1000/MWh that were not manually verified before the market run and $2,000/MWh cap that were not included in the market.

The costs eligible for after-the-fact recovery will be limited to documented actual costs. The supplier would have to incur these costs contemporaneously with the market they were used for and the gas system balancing rules would have to not allow any delay in procurement. In addition, the supplier will have to attest it does not have balancing group arrangements that allow it to delay purchasing gas. If a supplier can delay purchasing gas, it could presumably purchase gas at prices more consistent with the reasonableness threshold.

Hourly minimum load costs

Management proposes to change minimum load bids from daily to hourly bids. As described earlier, resources currently are unable to accurately reflect commitment costs because suppliers can only submit a single hourly minimum load cost for the entire day. Allowing minimum load cost bids that vary by hour will allow the ISO market to consider costs that may vary by hour and better enable suppliers to recover these costs.

Management also proposes to allow resources that do not have a minimum load output level, i.e. minimum load value is set at zero MW, to nonetheless have an hourly commitment that the market will treat the same as a minimum load cost. An example of such a cost is the cost for a demand response resource to maintain readiness to respond to a real-time market dispatch instruction.

Other changes

Finally, management proposes the following additional changes:

- Establish a negotiated option for determining commitment cost reference levels, similar to the existing negotiated option for determining default energy bids.

- Make permanent the existing temporary tariff provision that provides for the ISO to calculate reference levels for the day-ahead market based on natural gas price index information published by the Intercontinental Exchanges (ICE) based on “next-day” gas trading occurring on the morning of the day-ahead market. This is an important provision as it improves the accuracy of resource reference levels used for the day-ahead market.

- Make permanent an existing tariff provision that provides for the ISO to publish two-day-ahead advisory market results to market participants. This will benefit market participants as it allows them to better estimate day-ahead market results so they can more accurately purchase gas before the day-ahead market runs.

- Recalibrate the ISO market’s constraint relaxation price parameters to be consistent with the increased $2,000/MWh energy bid cap required by FERC Order No. 831. These price parameters are intended to be reflected in the market to reflect scarcity in the event the market has to relax a constraint to come to a feasible solution. They need to be proportional to the level of the energy bid cap to function appropriately.

POSITIONS OF THE PARTIES

Stakeholders are generally divided on the balance between increased bidding flexibility to allow suppliers to more accurately reflect costs versus protecting against market power and other adverse market behavior.

The ISO's Market Surveillance Committee, EIM participants, third-party generators, and the Environmental Defense Fund either strongly support management's proposal or support it as better than the existing rules but maintain it still does not offer enough bidding flexibility. These stakeholders strongly support management's proposal to allow "market-based" commitment cost cap bids that are only mitigated under local market power conditions, maintaining that ISO-calculated reference levels are often below resources' actual costs. These stakeholders believe it is important to expeditiously implement Management's proposal to correct this.

The Market Surveillance Committee concludes in its final opinion on Management's proposal as follows: "Overall, we support these elements of the CAISOs dynamic market power design and believe it will both enable the CAISO to provide more offer price flexibility to gas-fired resources within the CAISO during periods of gas price volatility and will also enable the CAISO to coordinate a more efficient market across the broader EIM region and better accommodate the diverse gas supply situations of utility generation across the west." The Environmental Defense Fund notes that Management's proposal is critical to ensure the full actual costs of gas-fired generation are reflected in the ISO market so that the ISO market does not overly rely on gas-fired generation, and thus increasing greenhouse gas emissions, by artificially suppressing its price.

EIM participants and third party generators generally maintain the commitment cost circuit breaker bid caps should be higher because they could restrict legitimate costs, especially during the initial 18-month phase-in period.

The ISO Department of Market Monitoring (DMM), as well as PG&E and SCE, appear to agree with Management's proposal in principle, but maintain it needs additional safeguards to protect against market power and other ways adverse market behavior could inflate costs. They maintain Management's proposal that allows suppliers to request adjustments to resource reference levels, and greater commitment cost bidding flexibility in general, may provide opportunity for adverse market behavior to inflate costs. DMM and PG&E also maintain the ISO should further test commitment cost local market power mitigation before implementing it. In response, Management changed its proposal by lowering the interim circuit breaker bid cap from 200 percent to 150 percent of a resource's reference level. This change allows additional protections during the first 18 months to ensure the new market power mitigation provisions are working as designed.

DMM and PG&E, as well as some other stakeholders, maintain the ISO should implement a DMM proposal to update the gas price used to calculate real-time market reference levels based on gas trades the ISO observes on ICE rather than implementing Management's proposed procedures for automated reference level adjustments.

Management believes its proposal strikes an appropriate balance between increased bidding flexibility to allow suppliers to more accurately reflect costs versus protecting against market power and other adverse market behavior. Management believes a core design principle should be that suppliers are much more able than the ISO to determine their costs. Management's proposal for commitment cost local market power mitigation is robust, and Management has examined the potential for other adverse market behavior to inflate costs under its proposal and has addressed all of the identified ways this could occur.

Management does not believe DMM's proposal to update real-time market reference levels based on gas trades observed on ICE would be consistent with FERC's recent guidance on the ISO's Aliso Canyon gas-electric coordination proposals. FERC has required the ISO to only use gas price index information that meets certain FERC standards. The gas trade information DMM proposes to use does not meet those standards. While management believes that gas trade information could be used, along with other information, as part of a manual reference level adjustment approval process, that process would be labor intensive. Management believes its proposal for an automated proposal strikes a balance between implementation cost and complexity, providing suppliers flexibility, and protecting against adverse market behavior.

A stakeholder comment matrix is included as Attachment A. The Department of Market Monitoring raised several concerns in their comments on the revised draft final proposal. Management has provided a detailed response to DMM's comments included as Attachment B. The Market Surveillance Committee provided a formal opinion on Management's proposals and is included as Attachment C.

CONCLUSION

Management requests Board approval of the proposal discussed above. The proposed changes will significantly improve suppliers' ability to accurately reflect cost expectations, provide an additional mechanism for cost recovery, and encourage increased participation from flexible resources in the ISO balancing area and the voluntary western energy imbalance market.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829)	)
BLUE MARMOT VI LLC (UM 1830)	)
BLUE MARMOT VII LLC (UM 1831)	)
BLUE MARMOT VIII LLC (UM 1832)	)
BLUE MARMOT IX LLC (UM 1833)	)
Complainants	)
vs.	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
Defendant	)
Pursuant to ORS 756.500.	)
	)

CONFIDENTIAL EXHIBIT BLUE MARMOT/403

REVIEW OF PACW-PGE TRANSMISSION STUDIES

PROTECTED INFORMATION SUBJECT TO GENERAL PROTECTIVE ORDER

(This exhibit has been sent separately)

June 18, 2018

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829)	)
BLUE MARMOT VI LLC (UM 1830)	)
BLUE MARMOT VII LLC (UM 1831)	)
BLUE MARMOT VIII LLC (UM 1832)	)
BLUE MARMOT IX LLC (UM 1833)	)
Complainants	)
vs.	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
Defendant	)
Pursuant to ORS 756.500.	)
	)

REPLY TESTIMONY OF

STEVE IRVIN AND

WILLIAM TALBOTT

ON BEHALF OF THE

BLUE MARMOT V, VI, VII, VIII, AND IX

June 18, 2018

I. INTRODUCTION

Q. Mr. Irvin, please state your name and business address.

A. My name is Steve Irvin. I am employed as an Executive Vice President with EDP Renewables North America ("EDPR NA").

Q. Are you the same Steve Irvin who previously submitted testimony in this proceeding?

A. Yes. My position and job responsibilities have not changed.

Q. Mr. Talbott, please state your name and business address.

A. My name is William Talbott. I am employed as a Development Project Manager with EDPR NA.

Q. Are you the same William Talbott who previously submitted testimony in this proceeding?

A. Yes. My position and job responsibilities have not changed.

Q. Please summarize what you believe to be the key issue in this proceeding.

A. Portland General Electric Company ("PGE") is refusing to accept and manage the net output from the Blue Marmot V, VI, VII, VIII and IX solar projects (the "Blue Marmots"), despite the Blue Marmots having purchased third party transmission from PacifiCorp to deliver their power to PGE at the PACW.PGE point of delivery ("POD"). The core issue in this proceeding is whether PGE will be required to take responsibility for the Blue Marmots' net output after the Blue Marmots have delivered their power to PGE's system. PGE's position is that it does not need to manage the Blue Marmots' net output, and that the Blue Marmots must not only deliver the power to PGE's service territory, but must deliver it to a location of PGE's choosing on its system.

Q. Please summarize your testimony.

A. Our testimony is brief because the core issue in this proceeding is a legal question of who is responsible for managing power after it is delivered to a utility.

First, our testimony responds to PGE's testimony that the Blue Marmots have a legally enforceable obligation ("LEO") to contract prices, but do not have a LEO to contract terms and provisions. We are not testifying as to whether PGE is correct as a matter of law, but to explain the practical and public policy implications of that position. A contract or other legal obligation to a price, without the corresponding terms and provisions, is worthless to a business because the economic value of a contract is based on the totality of all terms and conditions—not just the price.

Second, our testimony responds to PGE's lack of good faith efforts to accept and manage the Blue Marmots' delivered net output. PGE claims it has acted "precisely how a good faith business partner behaves when a problem arises during the contracting process."[1] We disagree. Without taking any time to review or explore all available options, PGE immediately reached the conclusion that PGE should not be responsible for the Blue Marmots' net output once it reaches PGE's system. PGE has expended considerable resources and efforts to avoid its obligations to accept and manage the power and very little (if any) effort attempting to fulfill its obligations.

Q. Please summarize Keegan Moyer's testimony.

---

[1] PGE/100, Greene-Moore/16.

A. Mr. Moyer is separately filing testimony that outlines a number of options that PGE could take to accept and manage the Blue Marmots' net output.[2] We want to emphasize that it is not the Blue Marmots' responsibility to identify all the ways in which PGE can accept delivery of power. We expect that PGE, with vastly more resources as the operator of its merchant and transmission functions, could identify solutions for accepting and managing the Blue Marmots' net output, if it chose to.

PGE has taken the position that it can refuse to accept the Blue Marmots' power that PacifiCorp will deliver to the PACW.PGE POD, and that PGE can demand that the Blue Marmots either: 1) build and pay for a 300-mile gen-tie line to interconnect with PGE's Bethel substation; or 2) purchase an additional wheel on BPA's transmission system to deliver to the PGE.BPA POD. Mr. Moyer's reply testimony focuses on PGE's claimed inability to accept the Blue Marmots' net output at the PACW.PGE POD, and concludes that PGE can accept the power with no reliability impacts and at no cost or significantly lower costs than PGE alleges. Mr. Moyer's testimony specifically responds to PGE's: 1) refusal to consider realistic options to accept the Blue Marmots net output; 2) flawed transmission study; and 3) inaccurate claims regarding how accepting the Blue Marmots' power would impact its participation in the Energy Imbalance Market ("EIM").

---

[2] Our summary does not address every point in Mr. Moyer's testimony but only the major themes.

Mr. Moyer explains that there are no reliability issues associated with accepting the Blue Marmots' net output at the PACW.PGE POD, and, from a power flow perspective, the impact of the Blue Marmots' power will be de minimis. Whether the Blue Marmots deliver to the PACW.PGE or BPA.PGE POD, the power flow impacts are essentially the same. The entire problem associated with the limited ATC at the PACW.PGE POD is due to the West's use of a contract path transmission management system, and PGE has elected to participate in the EIM in a manner that unnecessarily ties up otherwise available transmission capacity. To be clear, we are not recommending that the PGE disregard contract path transmission rights or not participate in the EIM; however, it is important to keep in mind that the problem has no basis in reliability or powerflow issues.

Mr. Moyer reviewed PGE's transmission study, which concludes that the only way in which the Blue Marmots can deliver their power at the PACW.PGE POD is to construct a 300 mile gen-tie line from Southern Oregon to Salem. This long transmission line would be built to address an only 16 MW capacity shortfall. Mr. Moyer explains that PGE failed to consider other technical alternatives to increasing TTC, and he reviews a number of other alternatives that would have sufficiently increased TTC, some of which would have required 15 miles rather than 300 miles of upgrades. His basic conclusion is that, under no circumstance is the best and most efficient solution for the Blue Marmots (or PGE) to build a 300 mile gen-tie line to address a small contractual capacity deficit that has no implications from a reliability and powerflow perspective. We are confident that PGE will implement a more cost effective solution that could impose little to no additional costs on PGE or its customers, if the Commission concludes that PGE must be responsible for accepting the Blue Marmots' net output at the PACW.PGE POD.

Mr. Moyer also testifies that PGE has taken an unreasonably restricted view of the options it has to manage the Blue Marmots' net output, and that PGE should consider other options that do not involve construction of new transmission and would enable it to meet its purchase obligation under PURPA, while allowing it to maintain its current level of EIM benefits. Mr. Moyer builds on the alternatives identified in our and his Direct Testimonies, which explain that PGE has many options to accept the power, including but not limited to better managing its transmission rights, using the power in support of its EIM transactions, making other off-system sales, and changing how PGE participates in the EIM. An illustrative example of PGE's hostile approach is that, when new transmission became available after PGE refused to execute PPAs with the Blue Marmots, PGE reserved this for itself rather than use it to accept the Blue Marmots' net output.

Mr. Moyer also responds to PGE's claim that any allocation of PGE's transmission to the Blue Marmots would mean that PGE could not "participate meaningfully" in the EIM. Mr. Moyer explains that PGE has chosen a manner of participating in the EIM that unnecessarily ties up available transmission, and results in PGE utilizing its full reserved transmission capacity on only very rare occasions. In fact, 97% of PGE's EIM imports require less than 250 MW of transmission capacity and PGE has at least 295 MW of EIM-dedicated transmission. This is an incredibly wasteful use of limited transmission capacity. Mr. Moyer explains how PGE could "participate meaningfully" in the EIM and allow a portion of its transmission to be better used not only for the Blue Marmots, but other cost effective resources that could otherwise deliver their power at the PACW.PGE POD.

Finally, Mr. Moyer explains that the Commission should address any concerns with accepting the Blue Marmots' net output on a prospective basis. Mr. Moyer points out that PGE has contracted with other QFs that are planning to deliver at the PACW.PGE POD, and there is no reason to allow them and not the Blue Marmots to deliver their power simply because PGE refused to counter sign the Blue Marmots' PPAs. The Commission should not adopt a new policy retroactively to the Blue Marmots, which were unaware that PGE would refuse to purchase their power until after they had signed PPAs that PGE stated were ready for execution.

II. <u>CONTRACT NEGOTIATIONS</u>

Q. Do the Blue Marmots and PGE agree on many aspects of the contract negotiation process?

A. Yes. PGE explains that it generally agrees with the contracting process discussed in Mr. Talbott's narrative in his direct testimony.[3]

Q. Messrs. Greene and Moore raised issues related to the Blue Marmots' LEOs being limited to the rates and not the terms and conditions. Please summarize their testimony.

[3] PGE/100, Greene-Moore/8.

A. Messrs. Green and Moore state that PGE "acknowledges that the Blue Marmots have a Legally Enforceable Obligation (LEO)—which PGE agrees locks in their right to the avoided cost rate in place at the time the LEO arises …."[4]

Q. What does this mean to you?

A. We understand that PGE's view is that all five of the Blue Marmot projects have LEOs to the avoided cost rates at the time that the LEO arose, which means that they are entitled to the avoided cost rates in effect on April 28, 2017. We understand that this means that regardless of the outcome of this proceeding, the Blue Marmots will be paid the contract prices in effect on April 28, 2017.

Q. Does PGE place any conditions on their acknowledgment that the Blue Marmots have LEOs?

A. Yes. Messrs. Green and Moore appear to take the position that none of the non-price terms and conditions in the Blue Marmots partially executed power purchase agreements are effective. We note these power purchase agreements and Schedule 201 materials are exactly the same as the Commission's approved standard power purchase agreements and Schedule 201. Messrs. Green and Moore specifically state that the Blue Marmots do not have fully executed contracts, and that it is PGE's opinion "***that all the Blue Marmots' PPA all specify that their terms and conditions are not effective until signed by both parties***."[5]

Q. What does this mean to you?

---

[4] PGE/100, Greene-Moore/14-15.
[5] PGE/100, Greene-Moore/15.

A. That PGE agrees that the Blue Marmots are entitled to a specific contract price, but that the Blue Marmots are not entitled to any specific contract terms and conditions. This means that PGE is reserving the right to change the contract provisions in the power purchase agreements that PGE provided to the Blue Marmots and that the Blue Marmots executed. Hence, PGE appears to be reserving the right to change the contractual provisions included in the Commission approved standard power purchase agreements and Schedule 201.

Q. Are you testifying regarding whether PGE's position is correct?

A. No. The Blue Marmots disagree with PGE's position, but we will address that in briefing.

Q. Is PGE's position that the Blue Marmots have a LEO as to price but not contract terms and conditions an important distinction?

A. Yes. PGE's commitment to pay the contract rate is essentially meaningless if the contract terms and conditions can be changed by PGE. These contracts include numerous provisions beyond the power price that can dramatically impact their overall value, including payments for surplus energy, damages for breach, security requirements, costs of transmission, delivery obligations, cure periods, contract length, etc. Each of these contract provisions impacts a renewable energy project's costs and/or revenues, and could make a project uneconomic despite the overall price of the contract. Any evaluation of project economics must therefore consider full contract terms and conditions in addition to pricing.

Q. Does PGE's position make sense to you?

A. No. To be clear, we are not testifying regarding the Commission or FERC's LEO standard or what it means. However, if the LEO standard is that a LEO entitles a qualifying facility ("QF") to the price alone and not the associated contract terms and conditions, then establishing a LEO is almost meaningless from a business perspective.

Q. What did the Blue Marmots understand when PGE informed the Blue Marmots that they had formed legally enforceable obligations.

A. Our understanding was that the Blue Marmots were entitled to both the prices *and* the contract terms and conditions in place when the LEO was established.

Q. What was your understanding of the transmission arrangements that PGE had agreed to when it sent executable power purchase agreements?

A. Our understanding was that PGE had agreed that the Blue Marmots would deliver their power to the PACW.PGE POD using third-party PacifiCorp transmission and paying PacifiCorp for the full costs of interconnecting their power to PacifiCorp's transmission system. This means that the Blue Marmots would not be required to either pay for additional transmission to deliver to a separate POD on PGE's system (i.e., the PGE.BPA POD), or pay for transmission upgrades on PGE's transmission system.

Q. What was the basis of this understanding?

A. PGE's communications with us during the course of the negotiations along with our reading of the Commission-approved standard power purchase agreement and PGE's Schedule 201.

For example, in two different locations, PGE's Schedule 201 states a QF must make "arrangements necessary for transmission of power to the Company's system"[6] and that "the Seller is responsible for the transmission of power at its

[6] Schedule 201-3.

cost to the Company's service territory."[7] The power purchase agreements tendered by PGE also include language that made it clear to us that the only transmission arrangements necessary were to purchase transmission from PacifiCorp to the PACW.PGE POD. Each of the power purchase agreements include an Exhibit B that lists "Required Facility Documents". These Exhibits include "Transmission Service Agreement with PacifiCorp", but no other transmission arrangements. The Exhibits also include a "Generator Interconnection Agreement", which is previously defined in the contract as being with PacifiCorp. Our understanding was that these Exhibits represented a complete list of the transmission and interconnection agreements necessary for PGE to accept the Blue Marmots' net output.

Q. Did PGE agree and understand that the Blue Marmots would be delivering to the PACW.PGE point of delivery and that there would not need to be any additional transmission or interconnection costs incurred by the Blue Marmots?

A. Yes. Based on our communications with PGE and PGE's provision of the draft and executable power purchase agreements, we believe that PGE had the same understanding. PGE then changed its position and broke its commitment, which PGE claims occurred because it later learned that there was limited available transfer capability ("ATC") at the PACW.PGE POD.

Q. Is it relevant that PGE changed its position after agreeing to accept the Blue Marmots' net output at the PACW.PGE point of delivery?

A. Yes. The legal implications of this will be addressed in legal briefing, but as a business matter, the Blue Marmots might have made different investment

---

[7] Schedule 201-20.

decisions if PGE had communicated earlier that additional transmission arrangements would be required for PGE to commit to buy the Blue Marmots' net output. Moreover, even by PGE's own account, it was a lack of internal coordination at PGE that caused PGE to change its position after providing executable contracts. QFs should be able to rely upon PGE's commitment to purchase their net output and upon PGE to thoroughly vet contract provisions regarding transmission and delivery before providing executable power purchase agreements.

III. PGE'S EFFORTS TO MANAGE THE BLUE MARMOTS' NET OUTPUT

Q. PGE claims that it has been a good faith business partner.[8] Do you agree?

A. No. Our initial testimony explains that PGE has not been a good faith business partner.[9] PGE's actions demonstrate that it has worked exhaustively to refuse to purchase the Blue Marmots' net output while making little to no effort to accept responsibility for managing the Blue Marmots' power. PGE's actions immediately after allegedly discovering that there was limited ATC at the PACW.PGE POD demonstrate this. PGE states that "as soon as PGE became aware of the constraint at the PACW-PGE interface, the Company reached out to the Blue Marmots to explain the situation, and to provide them with their available options."[10] The only two options that PGE provided were for the Blue Marmots to: 1) arrange to deliver output to the PGE.BPA POD; or 2) request a study to assess the upgrades necessary at the PACW.PGE POD, and agree to pay

8 PGE/100, Green-Moore/16.
9 Blue Marmot/100, Irvin/6.
10 PGE/100, Greene-Moore/16.

for the study and the required upgrades. This response foreclosed numerous other potential opportunities for the company to take responsibility for and manage the Blue Marmots' net output after delivery at the PACW.PGE POD.

Q. Has PGE's position changed regarding the Blue Marmots' options since its initial ultimatum?

A. Only marginally. PGE's original position was that the Blue Marmots must become transmission customers and request a transmission study from PGE Transmission. PGE now recognizes that PGE Merchant rather than the Blue Marmots should be the party to request such a transmission study. PGE's overall position that the Blue Marmots must deliver to another point on PGE's system (PGE.BPA POD) or pay for transmission upgrades has not changed.

Q. Would it have been possible for PGE to fully investigate all the options for it to accept and manage the Blue Marmots' net output in only a few days?

A. No. The Blue Marmots' direct testimony as well as Keegan Moyer's reply testimony have identified a number of potential options for PGE to accept and manage the Blue Marmots' net output. Regardless of whether PGE agrees on the feasibility of these alternatives, PGE did not attempt to investigate or understand any other options until after they had been identified by the Blue Marmots. A good faith business partner would have at least made an effort to identify and explore alternatives facilitating delivery at the disputed POD.

Q. Has PGE taken other relevant actions?

A. Yes. For example, additional ATC became available at the PACW.PGE POD after PGE's refusal to execute the Blue Marmots' contracts, which PGE acquired for uses other than accepting delivery from the Blue Marmots at this POD.

In addition, PGE previously executed contracts with other QF projects that specify delivery to the PACW.PGE POD. Other relevant provisions of these contracts are the same as the Blue Marmots' contracts. Despite PGE's completion of a transmission study focused on the PACW.PGE POD as part of this proceeding and extensive associated arguments, PGE has not communicated how it will handle these executed contracts with PACW.PGE PODs. From a business perspective, the Blue Marmots should at least be considered to be in the same position as these other projects, and should be treated no worse. PGE appears to be delaying answering how it will treat other QFs with PACW.PGE POD's so that the information cannot be used against PGE in this proceeding.

In sum, PGE has not attempted to work in good faith with the Blue Marmots to identify and explore solutions to the dispute at hand.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.