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June 26, 2020

Via Electronic Filing

Public Utility Commission of Oregon Attn: Filing Center 201 High St. SE, Suite 100 Salem OR 97301

> Re: In the Matter of PORTLAND GENERAL ELECTRIC CO. 2021 Annual Power Cost Update Tariff Docket No. UE 377

Dear Filing Center:

Please find enclosed the redacted version of the Opening Testimony and Exhibits of Lance D. Kaufman (AWEC/100 – 102) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that AWEC's testimony and exhibits contain protected information that is being handled in accordance with Order No. 20-100. The confidential portions of AWEC's filing have been encrypted with 7-zip software and are being transmitted electronically to the Commission and qualified persons, consistent with the Commission's Order No. 20-088.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

<u>/s/ Jesse O. Gorsuch</u> Jesse O. Gorsuch

Enclosures

#### **CERTIFICATE OF SERVICE**

I HEREBY CERTIFY that I have this day served the **confidential portions of the Opening Testimony and Exhibits of Lance D. Kaufman** upon the parties shown below via electronic mail, consistent with Commission Order No. 20-088.

Dated at Portland, Oregon, this 26th day of June, 2020.

Sincerely,

<u>/s/ Jesse O. Gorsuch</u> Jesse O. Gorsuch

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#### **BEFORE THE PUBLIC UTILITY COMMISSION**

#### **OF OREGON**

**UE 377** 

In the Matter of	)
PORTLAND GENERAL ELECTRIC COMPANY,	)))
2021 Annual Power Cost Update Tariff.	)

#### **OPENING TESTIMONY OF DR. LANCE D. KAUFMAN**

#### **ON BEHALF OF**

#### ALLIANCE OF WESTERN ENERGY CONSUMERS

#### (REDACTED VERSION)

June 26, 2020

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#### EXHIBIT LIST

AWEC/101 – Curriculum Vitae of Lance D. Kaufman

Confidential AWEC/102 – PacifiCorp Responses to Data Requests

1		I. INTRODUCTION AND SUMMARY
2	Q.	PLEASE STATE YOUR NAME AND OCCUPATION.
3	A.	My name is Lance Kaufman. I am the principal economist of Aegis Insight. My
4		qualifications are included in Exhibit AWEC/101.
5	Q.	ON WHOSE BEHALF YOU ARE TESTIFYING?
6	A.	I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC").
7		AWEC is a non-profit trade association whose members are large energy users in the
8		Western United States, including customers receiving electrical services from Portland
9		General Electric ("PGE" or "Company") in Oregon.
10	Q.	WHAT IS THE PURPOSE OF YOUR TESTIMONY?
11	А.	The purpose of my testimony is to address issues related to PGE's 2021 net variable
12		power cost forecast ("NVPC").
13	Q.	PLEASE SUMMARIZE YOUR TESTIMONY.
14	A.	I make the following recommendations:
15		1. Replace the 2018 Colstrip forced outage rate with the 20-year average.
16		2. Remove Beaver gas constraints from MONET. Make a similar adjustment to the
17		2021 PCAM.
18		3. Remove infant mortality forced outage rates from Carty's 4-year average and replace
19		with PGE's 2020 operational forecast for Carty's forced outages.
20		4. Modify the market depth calculations of Energy Imbalance Market ("EIM") benefits
21		to reflect only hours with increments, and only hours with decrements for average
22		increments and decrements, respectively.

5. Use the 4-year average of transmission resale revenues when forecasting transmission 1 2 resales. 3 6. Credit the 2021 NVPC forecast with the value of the 2015 BPA wheeling rights purchases, amortized over the expected expense of the purchased rights. Make an 4 5 equal adjustment to the 2021 PCAM. 6 The impact of these recommendations is summarized in the figure below. 7 Figure 1: Summary of AWEC Recommendations 8 9 **II. COLSTRIP FORCED OUTAGE RATE** 10 Q. HOW DOES PGE MODEL THE FORCED OUTAGE RATE ("FOR") FOR COLSTRIP? 11 12 A. PGE uses the average FOR from the previous four years. This method was approved in 13 Commission Order 10-414 in Docket UM 1355, which developed a method for 14 calculating the FOR for coal-fired generating resources. IS PGE COMPLYING WITH ALL OF THE REQUIREMENTS OF ORDER 10-15 **Q**. 414 IN MODELING COLSTRIP? 16 17 No. The Commission-approved methodology includes exceptions to using the most A. recent four-year average in modeling the FOR. Specifically, if the FOR falls outside of 18 the 10<sup>th</sup> or 90<sup>th</sup> percentile for comparable NERC coal units in a year, that year is 19 considered an "outlier year," is removed from the four-year average, and is replaced by 20

1		the 20-year rolling average FOR. <sup><math>1/</math></sup> Similarly, if a plant outage is determined to be due to
2		utility imprudence, it is excluded and replaced in the same manner. <sup>2/</sup> In this case,
3		Colstrip experienced an extended outage and deration in 2018 because the plant exceeded
4		its permit limits for Particulate Matter of 0.030 lbs/MMBtu, which informs the plant's
5		compliance with the Mercury and Air Toxics Standards (collectively, "MATS PM").
6		This outage and deration was due to imprudence on the part of all of the Colstrip owners,
7		including PGE.
8 9	Q.	WHY DO YOU CONCLUDE THAT THE 2018 COLSTRIP OUTAGE AND DERATION WAS DUE TO IMPRUDENCE?
10	A.	This was the finding of the Washington Utilities and Transportation Commission
11		("WUTC"), which held an investigation into this outage. This investigation, docketed as
12		UE-190882, included each of the investor-owned utilities subject to the WUTC's
13		jurisdiction: Puget Sound Energy, Avista Corp., and PacifiCorp ("IOUs"). The WUTC
14		concluded that each of these utilities had failed to demonstrate that they acted prudently
15		in addressing MATS PM violation and taking action to avoid this violation:
16 17 18 19 20 21		Regulated companies bear the burden of proving their decisions were prudent. Here, the record contains insufficient contemporaneous documentation of the [IOUs'] decision making in the period between the Q1 and Q2 MATS PM Testing. Accordingly, we base our decision on the [IOUs'] failure to sufficiently demonstrate the prudence of their actions and decisions leading up to the 2018 Colstrip outage. <sup>3/</sup>
22		The WUTC's final order includes a thorough and detailed description of the facts leading
23		up to the MATS PM violation that required Colstrip to be taken offline and later run at a
24		derated level. <sup>4/</sup>

<sup>&</sup>lt;u>1</u>/ Docket UM 1355, Order No. 10-414 at 5 (Oct. 22, 2010).

<sup>&</sup>lt;u>2</u>/

<sup>&</sup>lt;u>Id.</u> WUTC Docket UE-190882, Final Order 05 ¶ 43 (Mar. 20, 2020). <u>Id.</u> ¶¶ 22-39. <u>3</u>/

<sup>&</sup>lt;u>4</u>/

1	Q.	PLEASE SUMMARIZE THESE FACTS AS THE WUTC FOUND THEM.
2	A.	Quarterly testing of MATS PM at Colstrip consistently showed levels below permitted
3		limits until Q1 of 2018 when testing showed levels at the permitted limit of 0.030
4		lb/MMBtu. <sup>5/</sup> PGE confirmed that this is the limit. <sup><math>6/</math></sup> The results of the Q1 2018 test were
5		revealed to the Colstrip owners at the February 21, 2018 Owner & Operator ("O&O")
6		Committee meeting. <sup>7/</sup> Subsequent O&O Committee meetings were held on March 21,
7		April 18, May 16, June 20, July 18, August 15, and September 19 of 2018. <sup>8/</sup> The WUTC
8		also stated that Talen, the Colstrip operator, at times "communicated to the [IOUs] its
9		expectation and recurring recommendation that Colstrip would pass its second quarterly
10		(Q2) MATS PM Testing." <sup>9/</sup> However, as discussed below, any such communications
11		between the February 21, 2018 and June 20, 2018 O&O Committee meetings are not
12		apparent from the documents PGE provided in discovery in this case.
13		Q2 MATS PM testing revealed a site-wide emissions rate of 0.047 lb/MMBtu,
14		"an unprecedented exceedance of the site's 0.030 lb/MMBtu limit." $10/$ Units 3 and 4
15		went offline on June 28th and June 29th, respectively. <sup>11/</sup> The units went back online on
16		July 8th and July 17th, respectively, but only for purposes of "inspection, evaluation,
17		corrective action, and in-stack testing to determine compliance with emissions limits." $\frac{12}{2}$
18		The units were not brought fully back into service until September 2018. <sup>13/</sup>

- <u>Id.</u> ¶ 29. <u>Id.</u> ¶ 30. <u>8</u>/
- <u>9</u>/
- <u>Id.</u> ¶ 33. <u>10</u>/ <u>11</u>/
- <u>Id.</u> ¶ 35. <u>12</u>/
- Id. <u>13</u>/
- <u>Id.</u> ¶ 36

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<sup>&</sup>lt;u>5</u>/ <u>Id.</u> ¶¶ 27, 28.

<sup>&</sup>lt;u>6</u>/ AWEC/102 at 19 (PGE Response to AWEC DR 036).

<sup>&</sup>lt;u>7</u>/ WUTC Docket No. UE-190882, Final Order 05 ¶ 28-29.

# 1Q.WHAT DO THE DOCUMENTS PGE PROVIDED IN DISCOVERY REVEAL2REGARDING THE OWNERS' ATTENTION TO MATS PM LEVELS?

3	A.	The documents PGE provided align with the WUTC's conclusions. The WUTC found
4		that the Colstrip owners failed to keep sufficient contemporaneous documentation to
5		demonstrate their decision-making and attention to the elevated MATS PM levels. PGE
6		provided meeting minutes and agendas from each of the O&O Committee meetings from
7		February through June 2018. <sup>14/</sup> It also provided notes from each of these meetings except
8		for the February meeting, citing an inability to locate these notes due to staff turnover. $\frac{15}{10}$
9		None of these agendas, minutes, or notes mention MATS PM testing until the June
10		meeting, let alone indicate an effort to discover the cause of the increase in MATS PM
11		emissions, or identify an action plan or any other strategy the owners were considering to
12		reduce MATS PM emissions. This is despite PGE's notes from the January 2018
13		meeting stating that "
14		
15		·" <u>16</u> /
16		This is also in contrast to the August meeting notes, which state that "
17		
18		." <u>17</u> /
19		The only indication that MATS PM testing was discussed at the O&O Committee
20		meetings between the Q1 and Q2 tests are PGE's notes from the June meeting, which
21		reference the upcoming Q2 testing and state that

14/ AWEC/102 at 19-48 (PGE Response to AWEC DR 36).

<sup>15/</sup> <u>Id.</u> at 20. PGE also only provided meeting agendas for the January, February, and March meetings, and minutes for the January and February meetings.

- <u>16/</u> <u>Id.</u> at 26.
- <u>17/</u> <u>Id.</u> at 47.

<ul> <li>2</li> <li>3</li> <li>4</li> <li>5</li> <li>6</li> <li>7</li> <li>Q.</li> <li>WHA<sup>2</sup></li> <li>8</li> <li>A</li> </ul>	
<ul> <li>3</li> <li>4</li> <li>5</li> <li>6</li> <li>7</li> <li>Q.</li> <li>WHAT</li> <li>8</li> <li>A</li> </ul>	
4 pushed 5 pushed 6 Colstri 7 Q. WHA 8 A The W	
5 pushed 6 Colstri 7 Q. WHA 8 A The W	$\frac{18}{18}$ PGE's notes do not indicate that it or any other owner
6 Colstri 7 Q. WHA 8 A The W	l for proactive remedial efforts to minimize emissions and limit the impact to
7 <b>Q.</b> WHA'	p operations.
8 A The W	T DO YOU CONCLUDE FROM THIS INFORMATION?
	'UTC's conclusions appear to be sound and founded on evidence consistent with
9 that pr	ovided by PGE in this proceeding. If any owner, including PGE, took any action
10 to min	imize or prevent the risk of a MATS PM permit violation that would result in
11 penalti	ies and shutdown of the plant, there is no evidence of it. Accordingly, I agree with
12 the WI	UTC that, like the Washington IOUs, PGE has failed to demonstrate the prudence
13 of its a	actions leading up to the 2018 Colstrip outage and, therefore, this outage should be
14 remov	ed from the four-year average in forecasting the FOR for Colstrip in this case.
15	Order 10-414 states that:
16	If the Commission finds that any plant outage in the previous four years
1/	shall be replaced in the four year rolling average by the historical average
10	FOR as determined in step 5 above. Further, for any determination of
20	imprudence related to an outage occurring during the period of the
20	historical average, the vear(s) of the outage shall not be included in
22	calculating the historical average FOR. $\frac{19}{}$
23 I recor	
24 Order	nmend the Commission find this outage imprudent and treat 2018 consistent with

<sup>&</sup>lt;u>18</u>/ AWEC/102 at 44 (PGE Response to AWEC DR 36). Docket No. UM 1355, Order No. 10-414 at 5.

<sup>&</sup>lt;u>19</u>/

1	Q.	WHAT IS THE IMPACT OF YOUR RECOMMENDATION?
2	A.	Replacing 2018 with the 20-year historic average reduces the 4-year forced outage rate to
3		percent for Colstrip 3 and 4, respectively. This reduces the NVPC forecast
4		by \$1.1 million.
5		III. PORT WESTWARD COMPLEX GAS SUPPLY
6	Q.	PLEASE SUMMARIZE THIS ISSUE.
7	A.	PGE constrains the dispatch of Beaver in MONET due to gas supply constraints at the
8		Port Westward complex. <sup>20/</sup> Beaver's operation is constrained in every month in
9		MONET. This reduces Beaver's ability to serve PGE's peak loads and to operate when
10		marginal energy costs are high. PGE invested in Port Westward 2 to support a capacity
11		shortfall, incurring substantial capital costs. PGE's insufficient gas supply for the Port
12		Westward complex renders the Port Westward 2 ineffective. I recommend the
13		Commission find PGE's 2021 gas supply decisions for the Port Westward complex
14		imprudent and that the 2021 NVPC forecast be made assuming no gas constraint for the
15		Port Westward complex. This reduces the 2021 power cost forecast by \$3.4 million.
16	Q.	HOW GREAT IS THE CURTAILMENT OF BEAVER IN MONET?
17	A.	The figure below summarizes the number of hours Beaver is constrained in MONET. On
18		average Beaver is restricted to run per day in 2021. <sup>21/</sup> Curtailment is most
19		extreme in .

<sup>&</sup>lt;u>20</u>/

AWEC/102 at 4 (PGE Response to AWEC DR 22, part d). PGE MFR workpaper #M610PUC10-00i-2021 AUT.xlsm sheet "Gas Storage". <u>21</u>/

1 Figure 2: Confidential MONET Dispatch Constraints for Beaver Plant



# Q. WHY DOES PGE NOT HAVE SUFFICIENT GAS TO OPERATE THE PORT WESTWARD COMPLEX AT FULL CAPACITY?

A. AWEC requested that PGE explain the reason for insufficient gas supply to meet the
increased demand of the Port Westward complex. PGE responded that the 2009 IRP,
which identified the capacity need supporting Port Westward 2, assumed sufficient gas
supply for the project. PGE noted that it models Port Westward 2 at full capacity and did
not explain why there is insufficient gas supply for the Port Westward complex as a
whole, including for Beaver.<sup>22/</sup>

#### 10 Q. ARE YOU CHALLENGING THE PRUDENCE OF PORT WESTWARD 2?

11 A. No. The Commission has accepted the prudence of Port Westward 2. However, that

- 12 prudence appears to rest on the assumption that there is sufficient gas. Port Westward 2
- 13 was acquired to add capacity to PGE's system. However, PGE is serving the gas needs
- 14 of Port Westward 2 by reducing the capacity of Beaver. This capacity reduction offsets

<sup>22/</sup> AWEC/102 at 3-4 (PGE Response to AWEC DR 22).

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3		does not have sufficient gas supply.
4	Q.	IS PGE CURRENTLY ACQUIRING CAPACITY RESOURCES?
5	A.	Yes. PGE supplemented its filing in this case on June 8, 2020 to request inclusion of a
6		new capacity resource, the Douglas PPA, in the 2021 NVPC forecast.
7 8	Q.	IS IT POSSIBLE THAT THE COST OF SUPPLYING GAS TO BEAVER EXCEEDS THE BENEFIT?
9	A.	Yes, it is possible; however that should not be the basis for evaluating prudence of the
10		gas supply. Prudence of the gas supply should include consideration of the incremental
11		capacity costs of new capacity resources that PGE is acquiring, such as the Douglas
12		$PPA.^{23/}$ Without the gas constraint, PGE may have been able to avoid acquiring this
13		incremental capacity, or could have acquired a lower amount of capacity.
14 15	Q.	ARE THERE OTHER REASONS WHY PGE'S INABILITY TO MAXIMIZE ITS EXISTING CAPACITY RESOURCES IS CONCERNING?
16	A.	Yes. PGE has raised alarms in several recent dockets about diminishing capacity in the
17		West and the impact this may have on resource adequacy requirements. <sup>24/</sup> Yet, PGE

Port Westward 2's capacity contribution. Customers are paying the full cost of the Port

Westward 2 investment, but do not receive the originally projected benefit because PGE

- 18 itself does not appear to have taken the actions necessary to maximize its existing
- 19 resources' capacity contribution.

1

2

 $<sup>\</sup>frac{23}{}$  PGE/300, Seulean – Kim – Batzler/4.

<sup>&</sup>lt;sup>24/</sup> See, e.g., Docket UE 258, PGE/100, Sims-Tinker/4:23-8:15; Docket No. UM 2024, PGE Phase 1 Opening Comments at 4-5 (Mar. 16, 2020).

# Q. HAVE YOU EVALUATED THE COST OF SUPPLYING SUFFICIENT GAS AND THE CAPITAL COST OF PORT WESTWARD 2 AGAINST THE RELATIVE BENEFIT OF AVOIDING THE DOUGLAS PPA AND THE INCREMENTAL NVPC BENEFITS?

5	А.	No, it did not become apparent to me that PGE was curtailing Beaver due to gas supply
6		limits until after participating in the PGE AUT workshop on June 5, 2020 and reviewing
7		PGE's response to Staff DR $4.\frac{25}{}$ The full cost of not having sufficient capacity did not
8		become apparent until PGE filed supplemental testimony on June 8, 2020 requesting cost
9		recovery for the Douglas PPA. This allowed time for only one round of discovery
10		requests on the issue. Based on the data available there is sufficient cause to question the
11		prudence of not supplying Beaver with gas. PGE should bear the burden of
12		demonstrating that the lack of gas is prudent, particularly considering the late filing of
13		PGE's supplemental testimony requesting costs for a capacity resource.
14	Q.	WHAT IS YOUR RECOMMENDATION FOR BEAVER GAS CONSTRAINTS?
15	А.	I recommend removing the Beaver gas constraints in MONET. This reduces NVPC by
16		\$3.4 million. I also recommend that the effects of actual gas constraints at Beaver be
17		removed from NVPC in the PCAM by adding a credit equal to the difference between the
18		Beaver operating cost and the cost of replacement power in hours where PGE constrains
19		Beaver.
20		IV. CARTY FORCED OUTAGE RATE
21	Q.	PLEASE SUMMARIZE THIS ISSUE.
22	A.	PGE models the forced outage rate of Carty using two years of actual outage data and
23		two years of an "Initial" outage rate. The initial outage rate is percent. The two
24		years of actual outages rates are percent and percent in 2018 and 2019,

AWEC/102 at 49 (PGE Response to Staff DR 4).

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1		respectively. PGE states that the initial rate is high to account for infant mortality. Infant
2		mortality is a term that refers to higher outage rates during the first few "infant" years of
3		operation for a new plant. However, PGE admits that Carty will be past the infant
4		mortality stage in the middle of the power cost forecast year because it will have operated
5		for more than five years. <sup>26/</sup> I recommend replacing PGE's forced outage rate with an
6		outage rate calculated using PGE's 2018 through May 2020 actuals and June 2020
7		through December 2020 forecasted rate. This results in a forced outage rate of
8		percent. My recommendation reduces the 2021 NVPC forecast by \$520,000.
9 10	Q.	PLEASE EXPLAIN HOW PGE NORMALLY FORECASTS GAS FORCED OUTAGE RATES.
11	A.	PGE normally forecasts gas outage rates using a plant-specific four-year moving average
12		of the historic equivalent forced outage rate. PGE uses the methodology as a reasonable
13		predictor of future plant outages. PGE studied alternative approaches to forecasting
14		forced outages as part of the Commission's forced outage investigation in Docket No.
15		UM 1355. PGE found that 3- and 4-year rolling averages produced the lowest forecast
16		error compared to other years. $\frac{27}{}$
17 18 19	Q.	IS THE FOUR-YEAR ROLLING AVERAGE METHOD INTENDED TO INCORPORATE HISTORIC ABNORMAL EVENTS INTO FUTURE NVPC FORECASTS?
20	A.	No. The method was intended to generate an accurate forward-looking forecast of
21		normalized forced outage rates. PGE stated in Docket No. UM 1355 that it was

appropriate to remove outlying outage events.<sup>28/</sup> 22

<sup>&</sup>lt;u>26</u>/

AWEC/102 at 15 (PGE Response to AWEC DR 034). Docket No. UM 1355, PGE/100, Hager - Tinker/13, lines 4 and 5. Docket No. UM 1355, PGE/100, Hager - Tinker/13. <u>27</u>/

<sup>&</sup>lt;u>28</u>/

# 1Q.WILL INCLUDING CARTY'S "INFANT MORTALITY" OUTAGE RATE IN2THE 4-YEAR AVERAGE RESULT IN AN ACCURATE AND NORMALIZED3FORECAST OF CARTY'S OUTAGES?

- 4 A. No, PGE admits that Carty is past the infant mortality stage. Using two years of "infant
- 5 mortality" outage rates in the 4-year average will result in a forecast that is biased and
- 6 high.

# Q. WHY DO YOU RECOMMEND USING PGE'S 2018 THROUGH MAY 2020 ACTUALS AND JUNE 2020 THROUGH DECEMBER 2020 FORECASTED 9 RATE?

- 10 A. PGE also provided a Carty forced outage rate forecast for 2020 in response to AWEC DR
- 11 34.<sup>29/</sup> In Docket No. UM 1355 PGE showed that a 3-year average was as effective as a 4-
- 12 year average. PGE's analysis also showed that a 2-year average was also a good
- 13 predictor of forced outages. PGE's analysis is reproduced below. $\frac{30}{}$
- 14 Figure 3: UM 1355 PGE Analysis of Forced Outage Rate Accuracy



15 Using more recent data over a shorter period will prove more accurate than using a longer

16 period that includes outlying outages which are not expected in the future.

<sup>&</sup>lt;sup>29/</sup> AWEC/102 at 15-18 (PGE response to AWEC DR 34 Confidential Attachment CARTY REPORT\_AVAILABILITY\_2020YTD.xlsx).

 $<sup>\</sup>underline{30}$  Docket No. UM 1355, PGE/100, Hager - Tinker/13.

1	Q.	DOES PGE USE THE INFANT MORTALITY OUTAGE RATES IN
2		<b>OPERATIONAL (I.E., NON-AUT) DOCUMENTS?</b>

- 3 A. No. PGE provided an internal forecast of forced outage rate for Carty for 2020 in
- 4 response to AWEC DR  $34.\frac{31}{7}$  This forecast did not reflect future infant mortality and was
- 5 more consistent with the 2-year historic average.

#### 6 Q. PLEASE RESTATE YOUR RECOMMENDATION FOR THIS ISSUE.

- 7 A. I recommend replacing PGE's forced outage rate with an outage rate calculated using
- 8 PGE's 2018 through May 2020 actuals and June 2020 through December 2020 forecasted
- 9 rate. This results in a forced outage rate of percent. My recommendation reduces
- 10 the 2021 NVPC forecast by \$520,000.
- 11

12

#### V. EIM BENEFIT

# 13Q.PLEASE SUMMARIZE YOUR CONCERNS WITH PGE'S EIM BENEFIT14ESTIMATION.

15 A. PGE has modified its EIM Benefit calculation method in all but one AUT since entering

16 the EIM. Each variant of PGE's method has underestimated benefits. PGE's proposed

17 changes this year reduce the benefit forecast by \$3.8 million relative to what it would be

- 18 if PGE continued to use the method PGE proposed in the 2020 AUT.<sup>32/</sup> PGE's proposed
- 19 methodology has a critical flaw that prevents it from being an accurate and meaningful
- 20 model. When this flaw is corrected, PGE's proposed methodology is consistent with the
- 21 2020 AUT, i.e., both methods result in similar predicted benefits.

<sup>&</sup>lt;sup>31/</sup> AWEC/102 at 15-18 (PGE response to AWEC DR 34 Confidential Attachment CARTY REPORT\_AVAILABILITY\_2020YTD.xlsx).

AWEC/102 at 5-11 (PGE response to AWEC DR 26 Attachment E (summary sheet)) and PGE/100, Seulean – Kim – Batzler/10.

1		PGE's proposed model calculates the "market depth" of the EIM market within
2		any given hour as the hourly average historic increments and decrements within the
3		month. The critical flaw is that PGE averages increments across all hours within the
4		month, and decrements across all hours within the month, rather than averaging only
5		within hours where an actual increment or decrement occurs. This results in a large and
6		biased underestimate of the depth of the EIM market. I recommend modifying the
7		market depth calculations to reflect average volumes during periods of increments and
8		decrements separately.
9	Q.	PLEASE SUMMARIZE PGE'S PAST EIM BENEFIT FORECASTS.
9 10	<b>Q.</b> A.	<b>PLEASE SUMMARIZE PGE'S PAST EIM BENEFIT FORECASTS.</b> In the 2017 AUT, PGE forecast no EIM benefit due to uncertainty. <sup>33/</sup> In the 2018 and
9 10 11	<b>Q.</b> A.	PLEASE SUMMARIZE PGE'S PAST EIM BENEFIT FORECASTS. In the 2017 AUT, PGE forecast no EIM benefit due to uncertainty. <sup>33/</sup> In the 2018 and 2019 AUTs, PGE relied on a third-party study to forecast EIM benefits. <sup>34/</sup> In the 2020
9 10 11 12	<b>Q.</b> A.	PLEASE SUMMARIZE PGE'S PAST EIM BENEFIT FORECASTS.In the 2017 AUT, PGE forecast no EIM benefit due to uncertainty. <sup>33/</sup> In the 2018 and2019 AUTs, PGE relied on a third-party study to forecast EIM benefits. <sup>34/</sup> In the 2020AUT PGE proposed using historical values. PGE also introduced an additional benefit,
9 10 11 12 13	<b>Q.</b> A.	PLEASE SUMMARIZE PGE'S PAST EIM BENEFIT FORECASTS.In the 2017 AUT, PGE forecast no EIM benefit due to uncertainty. <sup>33/</sup> In the 2018 and2019 AUTs, PGE relied on a third-party study to forecast EIM benefits. <sup>34/</sup> In the 2020AUT PGE proposed using historical values. PGE also introduced an additional benefit,greenhouse gas revenues, which PGE received since the outset of EIM participation but
9 10 11 12 13 14	<b>Q.</b> A.	PLEASE SUMMARIZE PGE'S PAST EIM BENEFIT FORECASTS.In the 2017 AUT, PGE forecast no EIM benefit due to uncertainty. <sup>33/</sup> In the 2018 and2019 AUTs, PGE relied on a third-party study to forecast EIM benefits. <sup>34/</sup> In the 2020AUT PGE proposed using historical values. PGE also introduced an additional benefit,greenhouse gas revenues, which PGE received since the outset of EIM participation butdid not include in previous forecasts. <sup>35/</sup> In this filing, PGE proposes a sub-hourly dispatch
<ol> <li>9</li> <li>10</li> <li>11</li> <li>12</li> <li>13</li> <li>14</li> <li>15</li> </ol>	<b>Q.</b> A.	PLEASE SUMMARIZE PGE'S PAST EIM BENEFIT FORECASTS. In the 2017 AUT, PGE forecast no EIM benefit due to uncertainty. <sup>33/</sup> In the 2018 and 2019 AUTs, PGE relied on a third-party study to forecast EIM benefits. <sup>34/</sup> In the 2020 AUT PGE proposed using historical values. PGE also introduced an additional benefit, greenhouse gas revenues, which PGE received since the outset of EIM participation but did not include in previous forecasts. <sup>35/</sup> In this filing, PGE proposes a sub-hourly dispatch model to forecast EIM benefits. PGE's forecast and actual benefits are summarized

17 Figure 4: PGE Forecast and Actual EIM Benefit



<sup>&</sup>lt;u>33/</u> Docket No. UE 308, PGE/400, Niman - Peschka - Hager/20.

<sup>&</sup>lt;sup>34/</sup> Docket No. UE 319, PGE/300, Niman - Peschka - Rodehorst/17; Docket No. UE 335, PGE/300, Niman - Kim - Batzler/10.

<sup>35/</sup> Docket No. UE 359, PGE/100, Niman – Kim – Batzler/10-11.

1		PGE consistently under forecasts EIM benefits. This suggests that PGE is overly
2		conservative when forecasting EIM benefits.
3 4	Q.	DID PARTIES RAISE CONCERNS WITH PGE'S EIM BENEFIT FORECAST IN PAST CASES?
5	A.	Yes, parties noted that PGE's forecast in previous dockets appeared too low.
6 7	Q.	WHAT IS YOUR MAIN CONCERN WITH THE 2021 EIM BENEFIT FORECAST?
8	A.	PGE developed a model that substantially underestimates EIM benefits. PGE created a
9		sub-hourly dispatch model to estimate EIM benefits. PGE uses historic EIM transactions
10		to measure the market depth of this model. The market depth is used to limit the size of
11		increments and decrements. However, PGE uses the incorrect denominator when
12		calculating average historic increments and decrements.
13	Q.	WHAT ARE INCREMENTS AND DECREMENTS?
14	А.	Increments and decrements form the basic operations of the EIM. Increments are market
15		transactions where PGE is paid to increase generation. Decrements are market
16		transactions where PGE is paid to reduce generation. PGE calculates the average hourly
17		size of an increment by dividing total increments in a month by the number of hours in
18		the month. This underrepresents the average size of an increment because it includes
19		hours where no increment is made.
20 21	Q.	CAN YOU GIVE AN EXAMPLE THAT EXPLAINS WHY THIS APPROACH IS NOT CORRECT?
22	A.	The market depth measure is intended to measure the average size of a transaction.
23		Suppose you asked how much gas you purchased in an average transaction last year. The
24		correct answer is to add all gas purchases over the year and divide by the number of
25		transactions. The PGE approach is to take total gas purchases over the year and divide by

1		8760 hours. PGE's approach will clearly underrepresent the size of an average
2		transaction.
3	Q.	WHAT IS PGE'S ARGUMENT TO SUPPORT THEIR APPROACH?
4	A.	PGE argues that its method is appropriate because it helps to normalize historic
5		transactions. PGE states:
6 7 8 9 10 11		With respect to the increment and decrement amounts, PGE elected to use the total number of hours within each month in order to estimate the reasonable level of transactional volume that PGE could execute under normal market conditions, and the total number of hours is one approach for smoothing out the impacts from hours that had non-normal market conditions. <sup>36/</sup>
12		However, PGE's rationale is incorrect. PGE is not only smoothing transactions, PGE is
13		also shrinking transactions. Consider the treatment of forced outages. Historic forced
14		outages are normalized by averaging the annual outage rate across four years. The
15		annual outage rate does not include all hours in the year. For example, if a unit has a
16		planned outage, these hours are not included in the denominator when calculating the
17		outage rate.
18		Consider a coal plant that has a three-month planned maintenance outage and a
19		three-month unplanned outage. PGE's "all hours of the year" method would result in an
20		outage rate of $3/12 = 25$ percent. The correct method, and the method used in this case
21		for forced outages, excludes the months of planned outages, and results in an outage rate
22		of $3/9 = 33$ percent. In other words, including hours in the denominator that are not
23		relevant biases the estimate low.

<u>36</u>/

AWEC/102 at 13-14 (PGE response to AWEC DR 27, subpart c).

1 (	<b>Q</b> .	<b>WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?</b>
-----	------------	--

- 2 A. I recommend that historic average increments be calculated by dividing the total
- 3 increments within a month by the number of hours in that month that increments were
- 4 made. I recommend that historic average decrements be calculated by dividing the total
- 5 decrements within a month by the number of hours in that month that decrements were
- 6 made. This increases the EIM benefit forecast by \$4.6 million.

# Q. HOW DOES YOUR METHOD COMPARE TO THE ACTUAL HISTORIC BENEFIT PROPOSED BY PGE IN UE 359?

- 9 A. The gross EIM benefit of the sub hourly dispatch model, after my adjustment, remains
- 10 lower than the historic actual benefit method proposed by PGE in UE 359. The values
- 11 are compared in the figure below.

#### 12 Figure 5: AWEC Proposed EIM Benefit Vs. UE 359 Method



#### 13

#### VI. TRANSMISSION SALES REVENUE

- 14 Q. PLEASE SUMMARIZE THIS ISSUE.
- 15 A. PGE forecasts in transmission revenue for the 2021 NVPC forecast.  $\frac{37}{}$  The
- 16 figure below compares actual to forecasted transmission revenue from the last 10 years.
- 17 There is a clear history of under forecasting transmission resale revenue. I recommend
- 18 the Commission use the most recent four-year average transmission revenue.

<sup>&</sup>lt;sup>37/</sup> MFR workpaper #M610PUC10-00i-2021 AUT output.xlsm sheet "PwrCsOut" cell N322.

1 Figure 6: Confidential Transmission Resale Revenue



# 2 Q. HOW DID PGE FORECAST TRANSMISSION RESALE REVENUES IN ITS 3 INITIAL FILING?

- 4 A. In response to AWEC DR 17, PGE states:
- 5 For the 2021 NVPC modeling the transmission resale revenue forecast 6 assumes that PGE has 300 MW of transmission capacity available for 7 resale for Q1, Q2, and Q4 of 2021.<sup>38/</sup>

# 8 Q. HOW DID PGE FORECAST TRANSMISSION RESALE REVENUES IN 9 PREVIOUS FILINGS?

- 10 A. In response to AWEC DR 17, PGE states:
- 11PGE's transmission resale forecast for 2021 is similar to PGE's 2018 and122019 forecasts. In the 2015 through 2017 NVPC forecasts PGE was13modeling transmission resale revenues based on the long-term14transmission resale agreement with Shell Energy North America, LP15(Shell). The Shell agreement expired in December 2017. PGE did not16model transmission resales in the NVPC forecasts between 2010 and172014.<sup>39/</sup>

<sup>38/</sup> AWEC/102 at 1 (PGE Response to AWEC DR 17).

<sup>&</sup>lt;u>39/</u> <u>Id.</u> at 2 (PGE Response to AWEC DR 17).

#### HOW DOES PGE EXPLAIN THE DISCREPANCY BETWEEN FORECASTED 1 **O**. 2 **AND ACTUAL RESALES?** 3 PGE states that actual resale revenues in Figure 6 above do not account for incremental A. 4 costs associated with transmission resale, and that these costs are also not included in the 5 NVPC forecast. For example: 6 PGE would pursue transmission resales in the event a plant is placed in 7 an extended forced outage, if the transmission wasn't needed for 8 replacement power. In that case PGE would incur significant costs for 9 replacement power that would potentially more than outweigh the 10 transmission resale revenues. Moreover, PGE also incurs costs 11 associated with short term transmission purchases that are not modeled in 12 MONET and flow through the PCAM construct. $\frac{40}{}$ 13 14 DO YOU AGREE THAT ACTUAL TRANSMISSION RESALE VALUES DO **Q**. 15 NOT ACCOUNT FOR INCREMENTAL COSTS ASSOCIATED WITH FORCED 16 **OUTAGES?** 17 A. No. Forced outages are modeled in the AUT through a four-year average of forced 18 outages. To the extent that the four-year average transmission resale revenue is 19 associated with additional forced outage costs, these costs are accounted for through the 20 forced outage mechanism in MONET. 21 О. DO YOU AGREE THAT ACTUAL TRANSMISSION RESALE VALUES DO 22 NOT ACCOUNT FOR SHORT-TERM TRANSMISSION PURCHASES THAT 23 **ARE NOT MODELED IN MONET?** 24 I cannot confirm or deny PGE's assertion at this time. I requested that PGE provide data A. 25 necessary to compare actual transmission resales to forecast transmission resales. This 26 should have included information about the alleged short-term purchases. PGE did not 27 provide this information. To the extent that PGE believes it bears costs not included in 28 the AUT, PGE should propose methodologies to capture such costs.

 $\frac{40}{2}$  AWEC/102 at 2 (PGE Response to AWEC DR 17).

- 1 Q. WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?
- 2 A. I recommend the Commission increase transmission net resale revenue forecast by \$4.5
- 3 million as calculated in the table below. This decreases NVPC by an equal amount.
- 4 Figure 7: Transmission Resale Adjustment



5

#### VII. BPA TRANSMISSION RIGHTS PURCHASE

6 Q. PLEASE SUMMARIZE THIS ISSUE.

7 PGE acquired BPA transmission rights in 2015. This transaction involved a large A. 8 payment from the previous owners to PGE. The previous owners paid PGE because the 9 previous owners were not utilizing the rights and were being charged a deferral payment 10 by BPA. PGE assumed financial responsibility for the deferral payments to BPA in 11 exchange for the up-front payment by the previous owners. This transaction resulted in 12 an expected net gain for PGE of \$8.1 million dollars, calculated as the upfront payments 13 from the previous owners less the expected deferral payments to BPA. PGE recorded the 14 full amount of this gain in 2015 as a credit to net power costs. PGE should have 15 amortized the net amount over the life of the transmission contracts to match costs with 16 benefits. WHAT WAS THE IMPACT OF PGE'S TREATMENT OF THE PAYMENT IN 17 **Q**. 18 2015? 19 PGE executed a contract in 2015 that obligated customers to future power cost expense. A.

- 20 As part of this contract PGE experienced an expected \$8.1 million gain. The gain was
- 21 fully recorded in the 2015 PCAM as a credit to customers; however, due to the PCAM
- 22 mechanisms, none of this credit flowed through to customers. The transaction resulted in

UE 377 – Opening Testimony of Lance D. Kaufman (REDACTED)

1 an \$8.1 million dollar windfall for PGE shareholders and a multimillion-dollar 2 incremental cost to rate payers in the following years. 3 0. WHY IS THIS ISSUE BEING RAISED NOW, FIVE YEARS AFTER THE FACT? 4 A. PGE informed the Commission about this transaction on June 6, 2016 in its initial filing 5 for the 2015 PCAM, UE 310. However, PGE provides a very brief description of the 6 transaction: 7 O. Why did you include a credit for BPA wheeling rights? A. Because PGE acquired and paid for the BPA wheeling rights in 2015, it is 8 9 appropriate to reflect the net benefit of these rights in 2015 as a credit to power 10 costs. For accounting purposes, PGE recorded the payment as a regulatory asset and will amortize the balance upon taking the transmission service as an offset to 11 incurred costs. As PGE begins to use the wheeling rights and the regulatory asset 12 13 is amortized, we will reverse the accounting amortization entries from applicable PCAM filings.<sup>41/</sup> 14 15 PGE incorrectly stated "PGE acquired and paid for the BPA wheeling rights in 2015." 16 17 PGE did not pay for the transaction in 2015, PGE was paid for the transaction. Parties to 18 UE 310 were not presented with a clear explanation about how PGE received a large 19 payment in 2015, nor that this payment was tied to expense that would occur the 20 following years. 21 I am raising this issue now because customers are being asked to pay expenses in 22 this year's power costs associated with the wheeling rights, but did not receive any of the 23 benefits of the 2015 payment to PGE. 24 **O**. WHAT IS CORRECT TREATMENT OF THE NET GAIN FROM THE 2015 **TRANSACTION?** 25 26 The full payment for the transaction should have been recorded as a regulatory liability A. 27 and returned to customers proportionately to the expense of the contract. For example, if

<sup>41/</sup> UE 310, PGE/100, Tooman-Batzler/8.

- 1 the expenses associated with the contract were evenly spread over the following 10 years,
- 2 the gains from the payment should have been evenly spread over the following 10 years
- 3 and the unamortized balance of the contract should have reduced PGE's ratebase.

#### 4 Q. WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?

- 5 A. I recommend that the final 2021 NVPC forecast be reduced by the amount that customers
- 6 would have received had PGE correctly recorded and amortized this transaction. In
- 7 addition, the 2021 PCAM should include a credit of equal amounts. This treatment
- 8 should be continued in future AUT and PCAM filings. I need additional data from PGE
- 9 to complete the calculations for this adjustment.

# Q. ARE YOU RECOMMENDING THAT GAINS THAT SHOULD HAVE FLOWED THROUGH TO CUSTOMERS IN PREVIOUS YEARS UNDER YOUR PROPOSED METHODOLOGY BE REFLECTED IN THIS OR FUTURE AUT PROCEEDINGS?

- 14 A. No, the rule against retroactive ratemaking prevents those gains from flowing through to
- 15 customers now. My recommendation only proposes to flow gains through to customers
- 16 that should be realized in 2021 and onward.

#### 17 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

18 A. Yes.

#### **BEFORE THE PUBLIC UTILITY COMMISSION**

#### **OF OREGON**

UE 377

In the Matter of	)
PORTLAND GENERAL ELECTRIC COMPANY,	))))
2021 Annual Power Cost Update Tariff.	) ) _)

#### EXHIBIT AWEC/101

#### CURRICULUM VITAE OF LANCE D. KAUFMAN

#### **CURRICULUM VITAE**

LANCE KAUFMAN Aegis Insight 4801 W. Yale Ave. Denver, Colorado 80219 (541) 515-0380 lance@aegisinsight.com

#### **EDUCATION:**

University of Oregon	Ph.D.	Economics	2008 - 2013
University of Oregon	M.S.	Economics	2006 - 2008
University of Anchorage Alaska	B.B.A.	Economics	2001 - 2004

#### **CERTIFICATIONS:**

Certified Depreciation Professional

Society of Depreciation Professionals 2018

#### **PROFESSIONAL EXPERIENCE:**

Principal Economist	Aegis Insight	2014 - Present
Senior Economist	Oregon Public Utility Commission	2015 - 2018
Public Utility Advocate	Alaska Department of Law	2014 - 2015
Senior Economist	Oregon Public Utility Commission	2013 - 2014
Instructor	University of Oregon	2008 - 2012
Research Assistant	University of Alaska Anchorage	2003 - 2008

#### **PROFESSIONAL MEMBERSHIPS:**

Society of Depreciation Professionals	2015 - Present
American Economics Association	2017 – Present

#### RESEARCH, CONSULTING, AND ECONOMETRIC ANALYSIS:

- Jester, Gibson & Moore, Denver, CO 2019 Retained as an expert witness for plaintiffs regarding lost earnings in an ADEA wrongful termination matter.
- Albrechta & Coble, Ltd. Fremont, OH 2019 Retained as an expert witness for plaintiff regarding lost earnings in a race related wrongful termination matter.
- Conrad Law, PC, Salt Lake City, UT 2019

Retained as an expert witness for Ellis-Hall Consultants, LLC. regarding economic damages in Ellis-Hall Consultants, LLC. et. al. v. George B. Hofmann IV, United States District Court, District of Utah, Central Division.

 Davison Van Cleve, PC, Salem, OR 2019 Retained as an expert witness for Alliance of Western Energy Consumers regarding net variable power cost calculations in PORTLAND GENERAL ELECTRIC COMPANY,

2020 Annual Power Cost Update Tariff Public Utility Commission of Oregon Docket No. UE 359.

- Sanger Law, PC, Salem, OR, 2019
  - **Testified** as an expert witness for Renewable Energy Coalition and Rocky Mountain Coalition for Renewable Energy regarding Qualified Facility avoided costs in Application of Rocky Mountain Power for a Modification of Avoided Cost Methodology and Reduced Term of PURPA Power Purchase Agreements Public Service Commission of Wyoming Docket No. 20000-545-ET-18
- Sanger Law, PC, Salem, OR, 2019 Retained to provide analysis of Portland General Electric wind production costs in support of the Northwest & Intermountain Power Producers Coalition comments in Oregon HB 2857.
- Sanger Law, PC, Salem, OR, 2019
  - Retained as an expert witness for Cafeto Coffee Company regarding the necessity, design, and location of transmission lines in SPRINGFIELD UTILITY BOARD Petition for Certificate of Public Convenience and Necessity Public Utility Commission of Oregon Docket No. PCN 3.
- King & Greisen, LLP, Denver, CO 2018 Provided statistical analysis of age disparity in re Raymond et. al. v. Spirit Aerosystems, Inc. Civil Action No. 6:16-cv-01282-EFM-GEB.
- Baumgartner Law, LLC, Denver, CO, 2018 2019 Retained as an expert witness for plaintiffs re calculation of economic harm due to injury in re <u>Eric Bowman, v. Top Tier Colorado, LLC</u>, Case No. 18CV31359, United States District Court, District of Colorado.
- Cohen Milstein Sellers & Toll PLLC, Washington DC, 2018 Retained as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re <u>Isaac Harris et al. v. Medical Transportation Management, Inc.</u>, Civil Action No. 17-1371, United States District Court, District of Columbia.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2018 Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re <u>Vicky Maldonado and Carter v. Apple Inc., AppleCare Services</u> <u>Company, Inc., and Apple CSC, Inc.</u>, Case No. 3:16-cv-04067-WHO, United States District Court, District of California.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2018 –
   Deposed and testified as an expert witness for plaintiffs re calculation of unpaid mileage for truck drivers in re <u>Swift Transportation Co., Inc.</u>, Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2018 Retained as expert witness for plaintiffs re reasonable attorney fees in re Jeanne Stroup and Ruben Lee, v. United Airlines, Inc., Case No. 15-cv-01389-WYD-STV, United States District Court, District of Colorado.
- Klein and Frank, PC, Denver, Colorado, 2018
   Retained as expert witness for plaintiffs re potential jury bias in re <u>Gail Goehrig and</u> <u>Chris Goehrig v. Core Mountain Enterprises, LLC</u>, Case No. 2016CV030004, San Juan County District Court.
- Robert Belluso, Pennsylvania, 2017

Retained as expert witness for plaintiff re lost profit in re <u>Robert Belluso D.O. v Trustees</u> <u>of Charleroi Community Park</u>, PHRC Case No. 201505365, Pennsylvania Human Relations Commission.

- Lowery Parady, LLC, Denver, Colorado, 2017
  - Analyzed payroll data and calculated unpaid overtime and unpaid hours for plaintiff class action in re <u>Violeta Solis, et al. v. The Circle Group, LLC, et al.</u>, Case No. 1:16-cv-01329-RBJ, United States District Court, District of Colorado.
- Sawaya & Miller Law Firm, Denver, Colorado, 2017 Provided data processing and analysis of employment records.
- Financial Scholars Group, Orinda, California, 2017
   Provided analysis of risk profile in bundled real estate and personal loans in re <u>Old</u>

   <u>Republic Insurance Company v. Countrywide Bank et al.</u>, Circuit Court of Cook County, Illinois, Chancery Division.
- Financial Scholars Group, Orinda, California, 2017
   Provided consultation and analysis of financial market transactions in preparation of
   settlement claims filings in re Laydon v. Mizuho Bank, Ltd., et al. and Sonterra Capital
   Master Fund Ltd., et al v. UBS AG et al.
- Clean Energy Action, Boulder, Colorado, 2016 2017 Provided consultation on the appropriate discounting methodology used in energy resource planning in the Public Service Company of Colorado application for approval of the 2016 Electric Resource Plan, Proceeding No. 16A-0396E, Public Utilities Commission of the State of Colorado.
- Confidential Client, 2016 Provided analysis and report on the probability that distinct crimes are independent events based on geographical analysis of crime rates.
- Christine Lamb and Kevin James Burns, Denver, Colorado, 2016
   Provided data analysis for defendant of the impact of ethnicity on termination decisions
   in re <u>Aragon et al v. Home Depot USA, Inc.</u>, Case No. 1:15-cv- 00466-MCA-KK, United
   States District Court, District of New Mexico.
- Steptoe & Johnson LLP, Washington, DC, 2015 2016
   Programmed analysis of internet traffic data for plaintiffs applying a proprietary
   probability model developed to identify and verify accounts responsible for repeated
   infringements of asserted copyrights by defendants' internet subscribers in re <u>BMG</u>
   <u>BMG</u>
   <u>Rights Management (US) LLC, and Round Hill Music LP v. Cox Enterprises, Inc., et al.,
   Case No. 1:14-cv-1611(LOG/JFA), United States District Court Eastern District of
   Virginia, Alexandria Division.
  </u>
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2014 Programmed analysis for plaintiffs to calculate unpaid mileage for truck drivers in re <u>Swift Transportation Co., Inc.</u>, Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Padilla & Padilla, PLLC, Denver, Colorado, 2014 2016
   Provided research and analysis for plaintiffs re the impact on minority applicants from
   use of the AccuPlacer Test by the City and County of Denver, and estimated damages in
   re <u>Marian G. Kerner et al. v. City and County of Denver</u>, Civil Action No.
   11-cv-00256-MSK-KMT, United States District Court, District of Colorado.

 U.S. Equal Employment Opportunity Commission, 2013 – Provided statistical analysis of EEOC filings.

#### **REGULATORY PROCEEDINGS:**

- Portland General Electric 2016 Annual Power Cost Variance Docket No. UE 329.
- PacifiCorp 2016 Power Cost Adjustment Mechanism Docket No. UE 327.
- Public Utility Commission of Oregon Staff Investigation into the Treatment of New Facility Direct Access Charges Docket No. UM 1837
- PacifiCorp Oregon Specific Cost Allocation Investigation Docket No. UM 1824.
- PacifiCorp 2018 Transition Adjustment Mechanism Docket No. UE 323.
- Portland General Electric 2018 General Rate Case Docket No. UE 319.
- Avista Corp. 2017 General Rate Case Docket No. UG 325.
- Portland General Electric Affiliated Interest Agreement with Portland General Gas Supply Docket No. UI 376.
- Portland General Electric 2017 Automated Update Tariff Docket No. UE 308
- PacifiCorp 2017 Transition Adjustment Mechanism Docket No. UE 307
- Portland General Electric 2017 Reauthorization of Decoupling Adjustment Docket No. UE 306
- Northwest Natural Gas Investigation of WARM Program Docket No. UM 1750.
- PacifiCorp Investigation into Multi-Jurisdictional Allocation Issues Docket No. UM 1050.
- Idaho Power Company 2015 Power Supply Expense True Up Docket No. UE 305
- Homer Electric Association 2015 Depreciation Study U-15-094
- Submitted prefiled testimony regarding the depreciation study.
- Chugach Electric Association 2015 Rate Case U-15-081
- Developed staff position regarding margin calculations.
- ENSTAR 2014 Rate Case U-14-111
- Submitted prefiled testimony regarding sales forecast.
- Alaska Pacific Environmental Services 2014 Rate Case U-14-114/115/116/117/118 Submitted prefiled testimony regarding cost allocations, cost of service, cost of capital, affiliated interests, and depreciation.
- Alaska Waste 2014 Rate Case U-14-104/105/106/107 Submitted prefiled testimony regarding cost of service study, cost of capital, operating ratio, and affiliated interest real estate contracts.
- Fairbanks Natural Gas 2014 Rate Case U-14-102 Submitted prefiled testimony regarding cost of service study and forecasting models.
- Avista 2015 Rate Case U-14-104
  - Submitted analysis supporting OPUC Staff settlement positions regarding Avista's sales and load forecast, decoupling mechanisms and interstate cost allocation methodology. Represented Staff in settlement conferences on November 21, November 26, and December 4, 2013.
- Portland General Electric 2015 Rate Case
  - Submitted pre-filed opening testimony addressing PGE's sales forecast, printing and mailing budget forecast, mailing budget, marginal cost study, line extension policy and reactive demand charge. Represented OPUC Staff in settlement conferences on May 20, May 27, and June 12, 2014.

• Portland General Electric 2014 General Rate Case

Submitted analysis supporting OPUC Staff settlement positions regarding PGE's sales and load forecast, revenue decoupling mechanism, and cost of service study. Represented OPUC Staff in settlement conferences on May 29, June 3, June 6, July 2, and July 9 of 2013. Submitted testimony in support of partial stipulation, pre-filed opening testimony addressing PGE's decoupling mechanism, and testimony in support of a second partial stipulation.

• PacifiCorp 2014 General Electric Rate Case

Submitted analysis supporting OPUC Staff settlement positions regarding PacifiCorp's sales and load forecast and cost of service study. Represented Staff in settlement conferences on June 12 through June 14, 2013.

#### **BEFORE THE PUBLIC UTILITY COMMISSION**

#### **OF OREGON**

UE 377

In the Matter of	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
2021 Annual Power Cost Update Tariff.	) ) _)

#### EXHIBIT AWEC/102

#### PACIFICORP RESPONSES TO DATA REQUESTS

#### (REDACTED VERSION)

June 22, 2020

TO:	Jesse O. Gorsuch
	Alliance of Western Energy Consumers

FROM: Jaki Ferchland Manager, Revenue Requirement

#### PORTLAND GENERAL ELECTRIC UE 377 PGE Response to AWEC Data Request No. 017 Dated June 8, 2020

#### Request:

Please refer to the MFR file "#M610PUC10-00i-2021 AUT output.xlsm" Sheet "PwrCsOut", line 322. Please also refer to UE 362 PGE/100, Batzler - Cristea/5 at Table 1.

- a. Are transmission resales in Table 1 directly comparable to transmission resales on sheet "PwrCsOut" of the corresponding years' net power cost forecast? If no, why not?
- b. Please provide final NVPC forecast MONET output for each year from 2010 to present.
- c. Please provide the actual transmission resales amount for each year from 2010 to present.
- d. Please explain the variance, if any, between forecasts and actuals.
- e. Please include all additional data required to compare forecasted to actual resale revenues from 2010 to present.
- f. Please explain how transmission resale amounts are forecasted in the 2021 power cost forecast and identify any differences between the current method and the methods used for 2010 to 2020.

#### Response:

a. No. PGE's transmission resale forecast assumes a fixed amount of transmission capacity is available to for resale. The modeling is based on an agreement between stipulating parties in Docket No. UE 262 providing that beginning with its 2015 NVPC filing, PGE would include a proposed forecast of transmission resale revenue. Consequently, starting with the 2015 NVPC forecast, PGE has been including transmission resales revenues in the MONET modeling. For the 2021 NVPC modeling the transmission resale revenue forecast assumes that PGE has 300 MW of transmission capacity available for resale for Q1, Q2, and Q4 of 2021. PGE does not assume any transmission available to resale in Q3 due to expected transmission needs for PGE's load service obligation or PGE's Market Sales Obligation (Delivery to the market hub).

In actual operations PGE does not have a secured long-term transmission resale agreement and all transmission resales are pursued on a short-term basis (less than one year). Often this represents an instrument to optimize PGE's transmission needs to reliably serve our load and is based on the economics of PGE's generation plants. For example, PGE would pursue transmission resales in the event a plant is placed in an extended forced outage, if the transmission wasn't needed for replacement power. In that case PGE would incur significant costs for replacement power that would potentially more than outweigh the transmission resale revenues. Moreover, PGE also incurs costs associated with short term transmission purchases that are not modeled in MONET and flow through the PCAM construct.

- b. Confidential Attachment 017-A provides the NVPC MONET final output for each year from 2010 to 2020.
- c. Attachment 017-B provides the actual transmission resales reported in PGE's PCAM filings.
- d. Please see PGE's response to part a.
- e. PGE objects to this request on the basis that it is vague and overly broad. Subject to and without waiving this objection PGE responds as follows:

Please see PGE's responses to parts a through d. PGE does not have a secured long-term transmission resale agreement in real operations compared to the AUT assumption that PGE has a fixed 300 MW transmission available for resale.

f. PGE's transmission resale forecast for 2021 is similar to PGE's 2018 and 2019 forecasts. In the 2015 through 2017 NVPC forecasts PGE was modeling transmission resale revenues based on the long-term transmission resale agreement with Shell Energy North America, LP (Shell). The Shell agreement expired in December 2017. PGE did not model transmission resales in the NVPC forecasts between 2010 and 2014.

Attachment 017-A is protected information subject to Protective Order No. 20-100.

June 22, 2020

TO:	Jesse O. Gorsuch
	Alliance of Western Energy Consumers

FROM: Jaki Ferchland Manager, Revenue Requirement

#### PORTLAND GENERAL ELECTRIC UE 377 PGE Response to AWEC Data Request No. 022 Dated June 8, 2020

#### Request:

Please refer to PGE's response to Staff DR 4.

- a. Has PGE been unable to dispatch Port Westward or Beaver at full capacity due to gas constraints in December or January?
- b. Please provide the hourly generation of Port Westward and Beaver by unit from 2016 to present.
- c. Please provide the capacity of Port Westward and Beaver.
- d. In the 2021 NVPC forecast, does PGE restrict the dispatch of Port Westward or Beaver units to reflect gas constraints in December or January? If yes, please indicate where these constraints appear in the model. If no, why not?
- e. Which IRPs included supported the acquisition of Port Westward 2? Did the modeling in these IRPs limit the dispatch or gas availability for Port Westward 2? If no, why not? If yes, why does PGE not have sufficient gas supply to operate Port Westward 2 at full capacity?

#### <u>Response:</u>

- a. Yes, at times PGE has limited the Beaver dispatch in December or January to address gas supply constraints. PGE has not, however, limited the dispatch of Port Westward to address gas supply constraints. PGE does not specifically track when the Port Westward / Beaver complex has been unable to dispatch at full capacity due to firm gas supply constraints. In typical operations, if PGE experienced issues with gas supply PGE would limit the output of Beaver and fuel first Port Westward and Port Westward 2 (PW2). PGE has sufficient firm natural gas transportation rights to support the full dispatch capacity of Port Westward.
- b. For hourly generation from 2016 to 2019 please refer to PGE's MFRs filed April 15, Vol 11 Historical Data\Actual Hourly Energy for 2016-2019\Gas Plants. Confidential

Attachment 022-A provides hourly generation of Port Westward and Beaver from January 1, 2020 to May 31, 2020.

- c. Please refer to cells K606:V606 (Port Westward) and K604:V604 (Beaver) on the "PC Input" worksheet in the MONET model for monthly capacity values.
- d. The 2021 NVPC forecast reflects gas constraints for Beaver. The gas storage optimization in Step 0i estimates the available fuel supply for Beaver based on forecasted values for total available fuel supply at the Port Westward / Beaver complex, less the expected fuel demand for Port Westward and Port Westward 2. The 2021 NVPC forecast does not restrict the dispatch of Port Westward to reflect gas constraints. Please refer to cells C60:N104 on the "Gas Storage" worksheet in the MONET model for the fuel calculations.
- e. PGE's 2009 IRP action plan in Docket No. LC 48 identified the need for approximately 200 MW of flexible capacity to fulfill the dual purpose of meeting load during peak customer demand events as well as providing flexible capacity to follow both load and wind fluctuations. The ensuing 2012 Request for Proposal resulted in the selection of the PW2 project as the least cost, least risk bid. With information available at that time, PGE's 2009 IRP assumed that PGE's gas rights on the KB pipeline, future gas pipeline expansions planned for the area, and the pipeline connection to the Mist gas storage facility would meet the gas demand at PW2. Therefore, PGE did not limit the dispatch of PW2 in the 2009 IRP modeling. PGE is not limiting the PW2 dispatch for gas supply constraints in the current MONET modeling.

Attachment 022-A is protected information subject to Protective Order No. 20-100.

June 22, 2020

TO:	Jesse O. Gorsuch
	Alliance of Western Energy Consumers

FROM: Jaki Ferchland Manager, Revenue Requirement

#### PORTLAND GENERAL ELECTRIC UE 377 PGE Response to AWEC Data Request No. 026 Dated June 8, 2020

#### <u>Request:</u>

Please refer #M610PUC10-00d-2021 AUT output.xlsm cells F2096 to F2100.

- a. Do the referenced cells provide the 2020 AUT EIM benefit estimates, or the 2021 AUT EIM benefit calculated using the 2020 AUT methodology but with updated values?
- b. Please provide all workpapers used to calculate the 2020 AUT EIM benefit.
- c. Please provide the 2021 AUT EIM benefit calculated using the 2020 AUT methodology but with updated values. Please include all workpapers, including but not limited to workpapers aggregating EIM transactions from the real-time level.
- d. Please provide the actual GHG revenues by month from PGE's start of participation in EIM to present. Please include all workpapers, including but not limited to workpapers aggregating EIM transactions from the real-time level.
- e. Please provide historic EIM sub-hourly dispatch benefits by month from PGE's start of participation in EIM to present. Please include all workpapers, including but not limited to workpapers aggregating EIM transactions from the real-time level.
- f. If PGE declines to provide any part of this request, please provide the data necessary to make such calculations.

#### Response:

- a. Cells F2096 to F2100 are the 2020 AUT EIM benefits that PGE submitted as part of its net variable power cost filing in OPUC Docket No. UE 359. They are not 2021 AUT EIM benefits.
- b. Attachments 026-A through 026-D contain the workpapers submitted as part of PGE's Minimum Filing Requirements in OPUC Docket No. UE 359.

Attachment 026-A summarizes the benefit data, which is identified in part a of this response.

Attachment 026-B includes PGE's measurement of 2018 sub-hourly dispatch actuals with bid cost recovery included. See PGE's response to OPUC Data Request No. 070 for additional discussion on Bid Cost Recovery.

Attachment 026-C includes PGE's measurement of 2018 hydro GHG revenue that was used as the basis for the GHG benefit forecast.

Attachment 026-D includes PGE's measurement of grid management charges in 2018.

c. PGE objects to this request on the basis that it requires is overly broad, unduly burdensome, and requires new analysis. Without waiving and notwithstanding this objection PGE responds as follows:

Attachment 026-E provides a calculation of 2021 EIM benefit using the approach PGE utilized for its forecast of 2020 EIM benefits. Attachment 026-E includes a result with gross bid cost recovery dollars included in the calculation and a result with gross bid cost recovery dollars excluded. The result with gross bid cost recovery dollars included is consistent with the approach PGE utilized for its forecast of 2020 benefits (i.e., PGE included gross bid cost recovery dollars from 2019 to contribute to the creation of a 2021 EIM benefit forecast is unsuitable for several reasons. These reasons include:

- 1. PGE's participating resources received bid cost recovery dollars during the first quarter of 2019 that are not representative of the existing CAISO real-time market. During the first quarter of 2019, CAISO initiated a market software change that was impacting unit commitment logic in a manner that resulted in bid cost recovery dollars being assigned to PGE's participating resources. CAISO resolved the error in its unit commitment logic in March 2019, and the assignment of bid cost recovery dollars to PGE's participating resources was also reduced. PGE described the details of this impact in OPUC Docket No. UE 359.<sup>1</sup>
- 2. Bid Cost Recovery dollars received by PGE's participating resources can be offset by the Bid Cost Recovery charges PGE's EIM Entity is required to pay to CAISO. The EIM Entity is charged Bid Cost Recovery dollars, because PGE is often an importer in the EIM and importers bear the cost of the Bid Cost Recovery dollars paid to the resources committed by the market but not made whole by energy prices. See also PGE's Response to OPUC Data Request No. 98.

Since the use of bid cost recovery dollars is not appropriate for use in 2021 benefit forecasting, PGE included a second calculation with bid cost recovery dollars excluded in Attachment 026-E. See also PGE's response to OPUC Data Request No. 070.

Finally, PGE notes that its proposal in the 2020 AUT to use PGE's measurement of 2018 actual EIM benefits as a basis for forecasting 2020 benefits relied on the fact that the calendar year benefits were similar to normalized benefits produced from previous modeling efforts (which relied on production cost modeling). However, as PGE also

<sup>&</sup>lt;sup>1</sup> See PGE Exhibit 400, pages 13 and 14.

emphasized in OPUC Docket No. UE 359, its use of prior calendar year benefit measurements (i.e., dollars saved) will be an inappropriate basis for forecasting future dollars saved if the calendar year includes extraordinary (i.e., 'non-normal') events. PGE's calendar year 2019 benefit measurement includes extraordinary events.

- d. See PGE's Response to OPUC Data Request No. 076 for GHG revenues by month. Attachment 026-F provides revenue data at an interval level, but the data will differ slightly from the results reported in OPUC Data Request No. 076, because the interval level data is rounded when it is retrieved from PGE's PCI software.
- e. See PGE's Response to OPUC DR 70 for sub-hourly dispatch savings by month.

Workpapers used to calculate the sub-hourly dispatch savings by month include:

2020: Attachment 026-G includes the calculation of PGE's 2020 sub-hourly dispatch benefit by month with and without bid cost recovery dollars assigned to participating resources. The data is from January 1, 2020 through March 31, 2020. Attachment 026-H includes real-time level data from January 1, 2020 through March 31, 2020.

2019: Attachment 026-I includes the calculation of PGE's 2019 sub-hourly dispatch by month with and without bid cost recovery dollars assigned to participating resources. Attachment 026-J includes real-time level data from January 1, 2019 through December 31, 2019.

2018: See PGE's Response to AWEC DR 33 for 2018 real-time interval data.

2017: PGE does not have October 1, 2017 through December 31, 2017 data in a format comparable to data in 2018 and later, because prior to January 1, 2018 PGE's benefit estimation analysis was not fully integrated into its current software analytics tools.

In Attachments 026-H and 026-J the detail for thermal resources includes:

- 1. Base Schedule (MWh)
- 2. FMM Incr (MWh)
- 3. RTD Incr (MWh)
- 4. UIE Incr (MWh)
- 5. FMM EN Rev
- 6. RTD EN Rev
- 7. RTD UIE Rev
- 8. BCR

In Attachments 026-H and 026-J the detail for hydro resources includes:

- 1. Base Schedule (MWh)
- 2. FMM Incr (MWh)
- 3. RTD Incr (MWh)
- 4. UIE Incr (MWh)

UE 377 PGE Response to AWEC DR 026 June 22, 2020 Page 4

- 5. FMM EN Rev
- 6. RTD EN Rev
- 7. UIE Rev
- 8. BCR
- 9. Cost
- 10. P&L (Profit and Loss)

Throughout the year, PGE completed its benefit measurements after CAISO's T+12 settlement activity was complete for the relevant trading month. Since that time, T+55 settlement activity has been processed and results reported in Attachments 026-G and 026-I will not precisely match the real-time transaction level detail provided in this response.

f. See parts a through e

Attachments 026-B, 026-C, 026-D, 026-F, and 026-G through 026-J are protected information subject to Protective Order No. 20-100.

## UE 377

## Attachment 026-E

## Provided in Electronic Format

## PGE's Calculation of 2021 EIM Benefit Using the 2020 AUT EIM Benefit Forecast Method

#### AWEC/102 Kaufman/10

Bid Cost Recovery Included	2019 \$ Actuals	AWEC DR 026 Request Result for Part C	2019 \$ Actual sourced from Attachment 026-1	Escalator 2.5%
1 Western EIM Gross Benefit	\$8,981,619	\$9,436,314	2021 \$ escalates 2019 \$ Actual by 2.5 percent 2019 \$ Actual sourced from 2019 GMC Charges	
2 Settlement Charges	(\$1,024,744)	(\$1,076,622)	2021 \$ escalates 2019 \$ Actual by 2.5 percent	
3 Net EIM Benefit	\$7,956,875	\$8,359,692		
4 Hydro GHG Benefit	\$2,476,217	\$1,430,789	2019 \$ is 2019 Hydro FMM Revenue 2021 \$ reduces 2019 and escalates by 7.5% for inflation and real GHG price escalation	
Total Gross Benefit Total Net Benefit	\$11,457,836 \$10,433,091	\$10,867,102 \$9,790,480		
Bid Cost Recovery Excluded				
	2019 \$ Actuals	<u>AWEC DR 026 Request</u> <u>Result for Part C</u>	Notes	Escalator 2.5%
1 Western EIM Gross Benefit	2019 \$ Actuals \$6,310,449	AWEC DR US6 Request Result for Part C \$6,629,916	<u>Notes</u> 2019 \$ Actual sourced from Attachment 026-I 2021 \$ escalates 2019 \$ Actual by 2.5 percent 2019 \$ Actual sourced from 2019 GMC Charges	Escalator 2.5%
1 Western EIM Gross Benefit 2 Settlement Charges	2019 \$ Actuals \$6,310,449 (\$1,024,744)	<u>AWEL DR U26 Request</u> <u>Result for Part C</u> \$6,629,916 (\$1,076,622)	Notes         2019 \$ Actual sourced from Attachment 026-1         2021 \$ escalates 2019 \$ Actual by 2.5 percent         2019 \$ Actual sourced from 2019 GMC Charges         2021 \$ escalates 2019 \$ Actual by 2.5 percent	Escalator 2.5%
<ol> <li>Western EIM Gross Benefit</li> <li>Settlement Charges</li> <li>Net EIM Benefit</li> </ol>	2019 \$ Actuals \$6,310,449 (\$1,024,744) \$5,285,705	<u>AWEC DR 026 Request</u> <u>Result for Part C</u> \$6,629,916 (\$1,076,622) \$5,553,294	Notes 2019 \$ Actual sourced from Attachment 026-1 2021 \$ escalates 2019 \$ Actual by 2.5 percent 2019 \$ Actual sourced from 2019 GMC Charges 2021 \$ escalates 2019 \$ Actual by 2.5 percent	Escalator 2.5%
<ol> <li>Western EIM Gross Benefit</li> <li>Settlement Charges</li> <li>Net EIM Benefit</li> <li>Hydro GHG Benefit</li> </ol>	2019 \$ Actuals \$6,310,449 (\$1,024,744) \$5,285,705 \$2,476,217	AWEL DR 026 Request Result for Part C \$6,629,916 (\$1,076,622) \$5,553,294 \$1,430,789	Notes         2019 \$ Actual sourced from Attachment 026-1         2021 \$ escalates 2019 \$ Actual by 2.5 percent         2019 \$ Actual sourced from 2019 GMC Charges         2021 \$ escalates 2019 \$ Actual by 2.5 percent         2019 \$ actual sourced from 2019 GMC Charges         2021 \$ escalates 2019 \$ Actual by 2.5 percent         2019 \$ is 2019 Hydro FMM Revenue         2021 \$ reduces 2019 \$ Actual by 50% for quantity reduction and escalates by 7.5% for inflation and real GHG price escalation	Escalator 2.5%

#### AWEC/102 Kaufman/11

:	PodRonName           RNP1_2_BOARDWAN         BRP1_2_BOARDWAN         BRP1_2_ESCONTEL         CSP1_5_CONTEL         CSP1_5_CONTEL <th>3an \$22,666 \$1,291 \$7,702 \$360,841 \$103,853 \$41,069</th> <th>Feb \$15,324 \$77,593 (\$406,336) \$555,610 \$465,781 \$172,209</th> <th>Mar (\$8,362) \$23,485 \$45,885 \$111,300 \$217,566 \$196,624</th> <th>Apr \$0 (\$335) \$14,216 \$89,143 \$68,167 \$84,944</th> <th>May \$305 \$34,459 \$15,102 \$10,135 \$94,744 \$89,284</th> <th>Jun \$0 (\$53,778) \$85,934 \$94,561 \$62,044 \$69,602</th> <th>Jul \$7,815 (\$84,913) \$65,851 (\$69,570) \$51,976 \$39,165</th> <th>Aug \$31,252 (\$61,323) \$68,701 (\$24,482) \$82,955 \$44,580</th> <th>Sep \$58,134 (\$109,009) \$54,916 (\$82,512) \$110,525 \$60,056</th> <th>Oct (\$6,395) (\$73,277) \$34,882 (\$29,125) \$122,046 \$139,083</th> <th>Nov \$12,552 \$155,530 \$14,478 \$5,447 \$59,229 \$61,975</th> <th>Dec \$3,863 \$272,851 \$18,151 \$1,818 \$95,909 \$40,053</th> <th>Total \$137,154 \$182,573 \$19,482 \$1,023,168 \$1,534,795 \$1,038,644</th>	3an \$22,666 \$1,291 \$7,702 \$360,841 \$103,853 \$41,069	Feb \$15,324 \$77,593 (\$406,336) \$555,610 \$465,781 \$172,209	Mar (\$8,362) \$23,485 \$45,885 \$111,300 \$217,566 \$196,624	Apr \$0 (\$335) \$14,216 \$89,143 \$68,167 \$84,944	May \$305 \$34,459 \$15,102 \$10,135 \$94,744 \$89,284	Jun \$0 (\$53,778) \$85,934 \$94,561 \$62,044 \$69,602	Jul \$7,815 (\$84,913) \$65,851 (\$69,570) \$51,976 \$39,165	Aug \$31,252 (\$61,323) \$68,701 (\$24,482) \$82,955 \$44,580	Sep \$58,134 (\$109,009) \$54,916 (\$82,512) \$110,525 \$60,056	Oct (\$6,395) (\$73,277) \$34,882 (\$29,125) \$122,046 \$139,083	Nov \$12,552 \$155,530 \$14,478 \$5,447 \$59,229 \$61,975	Dec \$3,863 \$272,851 \$18,151 \$1,818 \$95,909 \$40,053	Total \$137,154 \$182,573 \$19,482 \$1,023,168 \$1,534,795 \$1,038,644
	MP-Rep_2_FEL88 VMP_1_PORTWEST1 VMP2_2_RECIP-6 VMP2_2_RECIP-12 Total Note(s)	\$203,352 \$19,306 \$22,999 \$26,394 <b>\$809,473</b>	\$697,009 (\$1,165) \$159,313 \$155,014 \$1,890,352	\$558,508 \$196,323 (\$115,330) (\$27,651) \$1,198,347	\$226,181 \$65,628 \$33,507 \$60,826 <b>\$642,276</b>	\$288,338 (\$32,708) \$85,370 \$67,197 \$652,227	\$255,333 \$10,186 \$41,495 \$128,293 \$693,671	\$74,367 (\$477) \$103,247 \$95,905 \$283,365	\$142,594 \$5,368 \$49,863 \$65,119 \$404,627	\$175,077 (\$44,957) \$25,688 \$31,544 \$279,462	\$256,679 (\$76,622) \$31,598 \$47,040 \$445,908	\$102,656 (\$65,421) \$64,839 \$104,241 \$515,529	\$97,140 \$49,318 \$365,095 \$222,183 \$1,166,382	\$3,077,234 \$124,778 \$867,685 \$976,106 \$8,981,619
Sub-Hourly	* Hydro benefits measured as EIM revenues Resource Summary Breakdown by Cate Bid Cost Recovery Dispatch Measurement (i.e., fuel cost savings) Total	against Powerdex ho. gory 3an \$347,662 \$461,811 \$809,473	Feb \$536,002 \$1,354,350 \$1,890,352	Mar \$222,141 \$976,206 \$1,198,347	Apr \$36,508 \$605,768 \$642,276	May \$80,514 \$571,713 \$652,227	Jun \$59,670 \$634,001 <b>\$693,671</b>	Jul \$289,051 -\$5,686 <b>\$283,365</b>	Aug \$121,802 \$282,825 \$404,627	Sep \$168,102 \$111,360 \$279,462	Oct \$147,279 \$298,629 \$445,908	Nov \$278,063 \$237,466 \$515,529	Dec \$384,376 \$782,006 \$1,166,382	Total \$2,671,170 \$6,310,449 \$8,981,619
Sub-Hourly	Reconciliation with OPUC DR 070 Dispatch Measurement (i.e., fuel cost savings)	Jan \$461,811	Feb \$1,354,350	Mar \$976,206	Apr \$605,768	May \$571,713	Jun \$634,001	Jul (\$5,686)	Aug \$282,825	Sep \$111,360	Oct \$298,629	Nov \$237,466	Dec \$782,006	Total \$6,310,449
PGE Response to OPUC DR 070	2019 Sub-Hourly Dispatch Benefit	(No Bid Cost Reco Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Bid Cost Recovery	3401,011	\$1,534,530	3376,200	3003,788	\$371,713	3634,001	(33,080)	\$202,023	\$111,500	\$238,023	\$237,400	\$782,000	<b>20,310,44</b> 3
	PositionName BNPL_5_BOARDMAN BRPL_5_BOARDMAN BRPL_5_BOARDMAN CSPL5_COYOTEL CYPL_5_CARTY1 MIDC_5_POESHARE	Jan 13,115 1,673 0 301,088 0	Feb 0 54,718 0 461,759 0	Mar 0 104,979 0 84,032 0	Apr 0 16,494 0 0 0	May 0 38,159 0 0	Jun 0 15,755 358 13,497 0	3ul 7,629 160,585 4 38,933 0	Aug 853 28,394 7 31,153 0	Sep 1,989 36,694 0 441 0	Oct 0 8,399 0 6,746 0	Nov 2,080 25,245 0 234 0	Dec 1,224 84,209 0 12,098 0	Total 26,890 575,304 369 949,981 0
	MULC_/_DUPURASHARE PMP-RBP_2_PELR8 PMP1_2_PORTWEST1 PMP2_2_RECIPI-6	0 23,105 5.153	0 8,076 5.111	0 0 8.611	0 0 7.121	0 0 21.442	0 0 19.497	0 1,103 52,567	0 3,940 30.367	0 0 47.243	0 0 53.178	0 0 92.295	0 2,965 178.048	0 39,189 520.633
	PWP2_2_RECIP7-12 Total	3,528 \$347,662	6,273 \$536,002	24,519 \$222,141	12,893 \$36,508	20,913 \$80,514	10,563 \$59,670	28,230 \$289,051	27,088 \$121,802	81,735 \$168,102	78,956 \$147,279	158,209 \$278,063	105,832 \$384,376	558,739 \$2,671,170
	Benefit - Net of BCR	-					_							
	PostconName BNP1_5_BOARDMAN BRP1_2_BEAVER1-7 CSP1_5_COYOTE1	9,551 (382) 7,702	15,324 22,875 (406,336)	(8,362) (81,494) 45,885	0 (16,829) 14,216	305 (3,700) 15.102	0 (69,533) 85,576	186 (245,498) 65,847	30,399 (89,717) 68.694	56,145 (145,703) 54,916	(6,395) (81,676) 34,882	10,472 130,285 14.478	2,639 188,642 18.151	110,264 (392,731) 19,113
	CYPL_5_CARTY1 MIDC_5_PGESHARE MIDC_7_DOPORGESHARE	59,753 103,853 41,069	93,851 465,781 172,144	27,268 217,566 196,624	89,143 68,167 84,944	10,135 94,744 89,284	81,064 62,044 69,602	(108,503) 51,976 39,165	(55,635) 82,955 44,580	(82,953) 110,525 60,056	(35,871) 122,046 139,083	5,213 59,229 61,975	(10,280) 95,909 40,053	73,187 1,534,795 1,038,579
	PNP-RBP_2_PELR8 PWP1_2_PORTWEST1 PWP2_2_RECIP1+6	203,352 (3,799) 17,846	697,009 (9,241) 154,202	558,508 196,323 (123,941)	226,181 65,628 26,386	288,338 (32,708) 63,928	255,333 10,186 21,998	74,367 (1,580) 50,680	142,594 1,428 19,496	175,077 (44,957) (21,555)	256,679 (76,622) (21,580)	102,656 (65,421) (27,456)	97,140 46,353 187,047	3,077,234 85,589 347,052
	PMP2_2_RECIP7-12 Total	22,866 \$461,811	148,741 \$1,354,350	(52,170) \$976,206	47,933 \$605,768	46,284 \$571,713	117,730 \$634,001	67,675 -\$5,686	38,031 \$282,825	(50,191) \$111,360	(31,916) \$298,629	(53,968) \$237,466	116,351 \$782,006	417,367 \$6,310,449
	FMM Inc MWh PositionName	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	BNPL_S_BOARDMAN BRPL_Z_BEAVER1-7 CSPL_S_COYOTE1 CYPL_S_CARTY1 MIDC_S_PGESHARE MIDC_7_DOPDPGESHARE	(2,943) 63 954 (406) (13,234) (4,175)	(2,873) 1,034 (8,141) (1,705) (16,351) (5,268)	(8,488) 1,281 1,666 (1,621) (8,504) (7,314)	0 1,494 1,596 6,088 722 (5,089)	0 (3,395) 1,070 260 3,007 2,705	0 (4,637) 10,097 11,432 (1,472) (3,749)	(10,641) (16,856) 7,674 4,289 (9,973) (5,044)	(10,470) (6,002) 5,206 2,597 (7,973) (4,157)	(18,878) (15,522) 4,737 (4,610) (12,314) (8,195)	(848) (9,439) 4,080 (2,863) (10,508) (12,542)	(6,716) (4,399) 2,915 (2,753) (3,206) (6,468)	522 (11,541) 3,115 (1,188) (8,754) (3,238)	(61,335) (67,919) 34,969 9,520 (88,560) (62,534)
	PMP1_2_PORTWEST1 PMP2_2_RECIPI-6 PMP2_RECIPI-6 PMP2_2_RECIPI-6	2,307 498	(4,203) 1,192 (1,222)	(2,866) 3,137	(8,181) 9,858 7,323	0 1,006 1.466	(11,521) 12,339 2,341 5,407	(18,322) 4,756 (679)	4,596	(3,315) (6,189)	(18,361) (8,742) (6,542)	(12,278) (10,477) (10,208)	(6,256) (15,337)	(232,428) (3,804) (22,582) (24,440)
	Total	(46,698)	(75,901)	(51,484)	17,406	(10,926)	20,327	(43,501)	(27,786)	(89,773)	(80,946)	(78,463)	(61,368)	(529,113)
	FMM EN Rev (\$) PositionName	Jan	Feb	Mar	Apr	Мау	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	BNPL5, BOARDMAN BRPL2, BBAVER1-7 CSPL5, COYOTE1 CYPL5, CARTY1 MIDC_5, PGESHARE MIDC_7, DOPORESHARE	(65,073) 1,059 59,964 347 (368,554) (113,624)	(146,372) 134,718 (361,836) 125,822 (808,223) (238,060)	(227,981) 63,442 91,389 44,064 (272,460) (209,333)	0 58,475 32,402 134,696 5,015 (72,279)	0 (74,145) 24,507 9,162 50,108 57,148	0 (160,206) 177,017 175,126 (29,944) (70,923)	(263,811) (561,160) 140,207 51,221 (232,694) (111,670)	(218,828) (198,090) 108,458 50,515 (192,332) (96,508)	(450,778) (462,107) 105,527 (96,968) (277,853) (188,468)	(15,814) (331,912) 89,166 (64,106) (248,703) (299,086)	(159,977) (116,155) 77,089 (76,536) (86,830) (166,641)	8,596 (471,007) 88,798 (27,628) (250,446) (92,949)	(1,540,038) (2,117,088) 632,688 325,715 (2,712,916) (1,602,393)
	NW-NBY_CYRLINS PWP122, PORTWEST1 PWP22, RECIP-6 PWP2_2, RECIP-12 Total	(831,894) 70,656 27,723 47,700 (\$1,171,696)	(2,028,725) (191,023) 210,542 41,711 (\$3,261,446)	(884,059) 33,728 118,833 55,168 (\$1,187,209)	(83,267) 241,589 216,803 119,365 \$652,799	(240,281) (39) 64,884 70,147 (\$38,509)	(286,061) 196,676 63,448 211,895 \$277,028	(431,530) 81,303 6,969 60,727 (\$1,260,438)	(349,205) 91,848 51,371 67,625 (\$685,146)	(70,235) (136,559) (218,376) (\$2,207,826)	(330,942) (223,424) (169,609) (397,285) (\$1,991,715)	(425,606) (323,059) (320,806) (596,314) (\$2,194,835)	(309,991) (198,392) (444,389) (136,982) (\$1,834,390)	(5,613,570) (290,372) (310,790) (674,619) (\$14,903,383)
	RTD Incr (MWh)	Jan	Feb	Mar	Apr	May	Jun	lut	Aug	Sep	Oct	Nov	Dec	Total
	ENPL 5, BOARDMAN BRPL, S. BOARDMAN SRJ, S. COVOTEL CYPL 5, CARTY I NDC, F, JOGENARE MDC, 7, DORPGESHARE MRC, 7, DORPGESHARE	(1,257) (126) (3,132) 1,688 (530) (336) (2,293)	15 (449) (4,184) 66 (2,790) (1,049) (3,323)	(373) (767) (5,306) (1,678) (1,819) (1,494) (3,358)	0 (379) (520) (1,165) (1,076) (913) (3,004)	0 (500) (681) (393) (1,924) (1,606) (4,078)	0 (364) (1,288) (162) (994) (1,246) (1,037)	(964) (1,434) (596) (7,896) (1,296) (881) (2,636)	457 (52) 335 (4,736) (1,162) (726) (2,832)	(317) (1,062) (470) (77) (920) (716) (1,404)	164 (401) (1,501) 218 (2,070) (1,500) (4,176)	(206) (582) (1,453) 3,240 (1,066) (567) (2,957)	(402) (347) (801) (662) (1,642) (633) (2,907)	(2,883) (6,463) (19,597) (11,557) (17,289) (11,667) (34,005)
	PMP1_2_PORTUEST1 PMP2_2_RECIPI-6 PMP2_2_RECIPI-12 Total	901 (108) (282)	523 (1,180) (1,506)	(594) (872) (515)	427 (838) (487)	25 (718) (259)	(769) (164)	428 (607) (194)	(36) (436) (369)	(109) (721) (522)	(1,015) (1,241)	(4/3) (855) (1,124)	(526) (1,322) (1,432)	(9,441) (8,095)
	RTD EN Rev (\$)	(614(6)	(//۵٫۵۰۱	(20,770)	1 (666,4)	(20,134)	(2,001)	120,010]	(/20/)	(۵۱۵,۵۶	(*1,015)	(Seo(6)	(20,074)	(+++) <sup>4</sup> 61)
	PositionName BNP1_5_BOARDMAN	Jan (26,279)	Feb 3,660	Mar (6,529)	Apr 0	May 0	Jun O	Jul (22,729)	Aug 7,575	Sep (5,741)	Oct 1,807	Nov (1,269)	Dec (5,982)	Total (55,487)
	BRP1_2_BEAVER1-7 CYP1_5_COVTE1 CYP1_5_CARTY1 MDC_5_FOESHARE MRC_7_COVENDESHARE RPF-RP1_2FB188 RVP1_2_FOETWEST1 PVP1_2_FOETWEST1 PVP2_2_RECIP1_6	(2,575) (65,155) 47,335 2,151 (3,649) (21,403) 27,466 (1,024)	(54,791) (161,465) 6,285 (37,349) (16,790) 299 26,071 (57,250)	(43,764) (82,096) (34,054) 4,727 46,321 52,902 19,862 (32,826)	(3,189) (5,897) 901 28,586 59,475 94,865 4,886 (32,909)	(23,462) (5,865) (1,941) 19,938 17,026 119,118 (1,236) (7,224)	(10,222) (30,315) (33,460) 16,580 17,963 157,309 730 (11,304)	(29,227) (3,491) (190,303) (19,588) (12,120) (46,219) 13,699 (10,037)	(201) 7,313 (112,776) (21,957) (13,679) (53,943) (917) (16,215)	(32,974) (3,500) 952 (1,687) (9,664) 37,116 (2,044) (15,507)	(6,515) (24,277) 8,582 (42,595) (23,265) (44,519) 1,754 (36,644)	(19,161) (25,183) 85,826 (23,080) 178 28,091 (12,328) (27,853)	(643) (11,841) (13,977) (33,188) (12,638) 98,780 (14,429) (38,380)	(226,724) (411,772) (236,630) (107,462) 49,158 422,396 63,514 (287,173)
	MW2_2_NECEP-12 Total	(\$48,619) (\$48,619)	(\$378,879) (\$378,879)	(\$86,384)	\$153,370	2,535 \$118,889	\$102,710	(\$321,185)	(\$212,775)	(\$43,173)	(\$197,239)	(\$28,972)	(\$74,640)	(\$1,016,897)
	UIE Incr (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	BNP1_5_BOARDMAN BRP1_2_BEAVER1-7 CSP1_5_COYOTE1	903 78 (298)	2,520 106 (473)	848 (61) (557)	0 131 (57)	22 211 73	0 (363) (953)	283 1,796 (2,124)	(138) 650 (784)	4 (183) (710)	708 107 (22)	451 230 (989)	435 693 (1,343)	6,036 3,395 (8,237)
	CYPL_5_CARTY1 MIDC_5_PGESHARE MIDC_7_DOPDPGESHARE	1,389 1,794 (139)	(761) 1,054 39	(738) 1,638 (246)	(239) 679 999	152 59 29	239 2,400 2,105	1,313 5,486 1,509	17 4,923 2,701	(536) 3,647 1,289	(406) 1,333 1,717	119 668 908	419 455 250	968 24,136 11,161
	PMP-RBP_2_PELR8 PMP1_2_PORTWEST1 PMP2_2_RECIPI-6 PMP2_3_RECIPI-6	206 383 (154)	(497) (169) (160)	548 (117) 113 (100)	126 (333) (99)	885 (269) (141)	948 (471) (209)	385 (2,157) (354)	1,959 (2,444) (553)	1,272 (1,609) (474)	2,995 (565) (286)	2,420 (510) (199)	3,494 (2,198) (399)	14,741 (10,459) (2,915) (4,620)
	Total	(00) 4,102	(211) 1,448	(190) 1,238	(161) 1,046	(324) 697	(421) 3,275	(435) 5,702	5,554	(550) 2,150	(517) 5,064	(334) 2,764	(059) 1,147	(4,039) 34,187
	RTD UIE Rev (\$) PositionName	Jan	Feb	Mar	Apr	Мау	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	8NP1.5.BOARDMAN 8RP1.2.BEAVER1-7 CSP1.5.COVTE1 CTP1.5.CARTY1 NDC.5.7.DOPGRESHARE NDC.7.DOPGRESHARE MDC.7.DOPGRESHARE MR.RP.2.PEL88	23,951 2,151 (10,233) 37,953 45,635 (4,903) (1,731)	149,360 14,777 (35,075) (65,328) 40,943 427 (59,856)	21,736 (6,799) (19,606) (38,251) 48,946 (4,633) 17,535	0 2,371 (4,055) (22,285) 6,480 (11,034) 7,775	305 4,017 (1,784) 3,034 (9,858) (8,852) 24,525	0 (11,427) (23,024) (5,704) 42,031 46,395 21,344	845 34,967 (51,400) 21,564 121,034 32,730 5,870	(5,931) (1,992) (16,585) (6,615) 112,564 63,415 47,402	(2,039) 10,182 (22,532) (21,670) 96,126 36,481 89,289	8,262 7,002 (4,105) (10,399) 36,470 50,142 84,646	13,114 7,907 (30,276) 4,765 15,864 22,687 (640)	15,704 27,663 (44,280) 10,175 6,409 7,554 (17,684)	225,307 90,819 (262,955) (92,761) 562,644 230,409 218,475
	PMP1_2_PORTWEST1 PMP2_2_RECIPI-6 PMP2_2_RECIPI-12 Total	(2,127) (3,026) (2,287) \$85,383	(16,147) (9,169) (5,635) \$14,297	(6,571) 2,669 (10,488) \$4,538	(13,753) 3,419 (3,820) (\$34,902)	(36,342) 8,519 (12,879) (\$29,315)	(17,463) (9,510) (15,226) \$27,416	(52,146) 22,801 20,685 \$156,950	(59,456) (12,822) (19,054) \$100,926	(45,763) (12,074) (13,381) \$114,619	(18,230) (5,128) (12,988) \$135,672	(24,693) (2,587) (6,289) (\$148)	(66,351) 6,601 (8,094) (\$62,303)	(359,042) (10,307) (89,456) \$513,133

June 22, 2020

TO:	Jesse O. Gorsuch
	Alliance of Western Energy Consumers

FROM: Jaki Ferchland Manager, Revenue Requirement

#### PORTLAND GENERAL ELECTRIC UE 377 PGE Response to AWEC Data Request No. 027 Dated June 8, 2020

#### Request:

Please refer to #FINAL\_Hydro Limit Summary.xlsx, sheet Hydro\_Pivo, columns G and H.

- a. Do these values represent the hourly limit for hydro resource EIM dispatches in PGE's EIM benefit model? If no, what are these values used for in the EIM benefit model?
- b. Please explain why PGE believes these values represent the appropriate hourly limit for limit for hydro resource EIM dispatches in PGE's EIM benefit model.
- c. Please explain why the average increment and decrement amounts are calculated using the total number of hours within each month, rather than the total number of hours in the month with increments and the total number of hours within each month with decrements.

#### Response:

- a. No, not predominantly. The purchase (i.e., "Dec") limits are predominantly transactional volumes where PGE is using its base schedule and bids to purchase energy from the EIM during the hour (instead of the real-time market prior to the balancing hour). That is, Dec limits are effectively capturing trading activity PGE implements without impacting PGE's intended hydro dispatch. With respect to sales (i.e., "Inc") limits, it is more often the case that a hydro dispatch would support the sale. Therefore, the Inc limit will effectively represent EIM dispatches. In part b of this response, PGE explains why "EIM dispatch" is a small part of the hourly limit.
- b. PGE discussed its method for attaining value from hydro resources in its technical workshop presentation on June 5, 2020. The presentation materials are included in PGE's Response to AWEC Data Request No. 32. Slide 9 of the presentation provides an example of using hydro base schedules and bids as a method to purchase energy in the EIM. In the example, the predominant benefit driver is CAISO "re-scheduling" the resource from 125 MW to 25 MW in the fifteen-minute market. This "re-scheduling" is effectively transactional purchase volume that PGE is implementing through EIM scheduling and bidding. PGE has identified a need to purchase energy and is electing to purchase the

energy via the EIM during the hour instead of through the bilateral real-time market prior to the hour. In other words, PGE's intended dispatch (i.e., desired operating level) for the hydro resource based on its resource planning and optimization prior to the operating hour was 25 MW. Instead of purchasing 100 MW bilaterally prior to the trading hour, the real-time trader elected to purchase the energy via the EIM through their use of the hydro base schedule and accompanying bids.

Because the predominant EIM benefit driver associated with hydro is the base schedule as a trading tool, not EIM dispatch, the limits are the appropriate limits for assessing the value hydro resources provide via EIM. If PGE limited the hydro volumes to dispatches (i.e., deviations from the planned operating level prior to the operating hour communicated via base schedules and bids), the hydro limits, particularly for purchase volume, would be much smaller. PGE also notes that under the current method, MONET hydro energy generation does not recalibrate each hour based on EIM dispatches. Therefore, there is likely a small increase in power costs not accounted for in the current MONET / EIM benefit construct. However, since hydro sales that result from EIM dispatch are less frequent and lower in magnitude, PGE believes the simplification is reasonable as part of its effort to more closely align NVPC forecasts resulting from MONET and EIM assumptions.

c. As is the case with many MONET inputs and the AUT/PCAM construct, PGE seeks to establish a NVPC forecast based on a set of conditions and assumptions that does not overweight real-world conditions that deviate from the MONET/AUT construct of 'normal' operating conditions.

With respect to the increment and decrement amounts, PGE elected to use the total number of hours within each month in order to estimate the reasonable level of transactional volume that PGE could execute under normal market conditions, and the total number of hours is one approach for smoothing out the impacts from hours that had non-normal market conditions.

As the question in part c. suggests, there are other approaches. PGE notes that if only the total number of hours in the month with increments (or decrements) is used, the value may be more susceptible to events in historical data that do not represent 'normal' operating conditions. For example, included in PGE's Q1 2019 operating data are the market impacts from the Enbridge gas pipeline explosion as well as unexpected cold weather and below normal hydro during February 2019 that caused Mid-C prices to clear considerably above expectations in the AUT forecast. This was a time period where PGE's hydro trading methods in the EIM were used extensively in 'non-normal' conditions, because it could purchase more economically in the EIM (relative to the real-time bilateral market). In other words, PGE had a higher decremental ("Dec") volume than PGE would expect under normal market conditions. If PGE established the decrement average using only decrement hours during the 'non-normal' conditions, it would likely over-predict usage in future years.

Table 1 compares the hydro decrement limit in PGE's initial filing to the method identified by AWEC in part c. of this response. If the 2019 data was used to predict hydro decrement volumes in 2020, AWEC's method would have over-predicted decremental trading (based only on the averages of hours when decremental trading occurred) in every month. PGE's

method would have more closely aligned with the 2020 results based on the alternative method identified in part c. Employing the approach identified by AWEC in part c of DR 027 would likely require the use of multiple years of data or an identification and removal of outlier data impacting both incremental and decremental limits in order to more reasonably represent 'normal' market conditions.

Finally, PGE notes that while its use of all hours in a month places downward pressure on the average, PGE also places upward pressure on the average through its use of 5-minute data instead of a net hourly value. For example, if a hydro resource decreased 5 MW from its base schedule during the first 5-minute interval and increased 5 MW from its base schedule during the second 5-minute interval, PGE's method includes the 5MW in its hydro limit calculation for both "Inc" and "Dec" directions, where the hourly aggregated value would have shown 0 MW in the limits calculation. The 0 MW result from a net hourly value is more closely aligned with the bi-lateral trading timeline where decisions to buy or sell are for a forward hour, not a 5-minute to 5-minute basis. Attachment 027-A provides the analysis that informs the hydro decrease limits reflected in the table below.

Table 1 - Hydro Decrease Limit					
	2019	2019	2020		
	PGE Initial Filing	AWEC DR 27	AWEC DR 27		
		Method	Method		
Jan	87.31 MW	133.64 MW	104.12 MW		
Feb	119.51 MW	166.36 MW	110.08 MW		
Mar	91.90 MW	143.83 MW	114.84 MW		

Attachment 027-A is protected information subject to Protective Order No. 20-100.

June 23, 2020

TO:	Jesse O. Gorsuch
	Alliance of Western Energy Consumers

FROM: Jaki Ferchland Manager, Revenue Requirement

#### PORTLAND GENERAL ELECTRIC UE 377 PGE Response to AWEC Data Request No. 034 Dated June 9, 2020

#### <u>Request:</u>

Please refer to MFRs (confidential)\Vol 3 - Thermal\Thermal Forced Outage\Carty\Data 2019. Please provide this data for 2016, 2017, and 2020.

- a. Please clarify what infant mortality is.
- b. Does PGE expect Carty to continue experiencing infant mortality issues in 2021 operations? If no, why is the value in the referenced file included in the 2021 AUT forecast?
- c. Please refer to Docket No. UE 1355 PGE/100 Hager Tinker/14 at lines 4 to 7. Please provide all materials from each of the referenced sources regarding Carty or similar unit outage rates.

#### <u>Response:</u>

Confidential Attachment 034-A provides Carty availability reports for 2016, 2017, and January to May of 2020.

- a. "Infant mortality" is a slang term used in the industry to describe the premature failure of equipment and parts. This occurs when a series of new parts and equipment are simultaneously installed in a new plant during construction, and a certain percentage of them fail at a faster rate than planned. Often during the first few years of operation, there are some parts and equipment that will fail faster than the normal population of parts, typically due to manufacturing faults. After the initial 3 to 5 years, plants are often thought to have passed through the "infant mortality" of parts period, and then proceed into a period of normal forced outage rates for similarly designed plants with similar ages of equipment.
- b. In July 2021 Carty will have been operational for 5 years and will be out of the "infant mortality" period. The value is referenced in the supporting data for 2021 modeling because the Carty forced outage rate forecast uses 2016 and 2017 initial forced outage rate estimates that include the infant mortality assumption.

c. The UM 1355 citation referenced by AWEC is specific to PGE's Port Westward plant. PGE does not have similar materials related to Carty. As noted in UM 1355 PGE/100 Hager-Tinker/14, lines 15-16, the methodology applied to develop an estimate forced outage rate for the first years of Port Westward operations is not necessarily applied to all new gas facilities.

As noted in the MFRs, to develop the forced outage rate estimate for MONET modeling when Carty was added to PGE's resource portfolio in the 2016 general rate case, PGE relied on discussions with PGE's Generation Projects and also reviewed NERC data for similarly sized Combined Cycle Combustion Turbine gas plants that were built recently. Please see these supporting materials in PGE's April 15 MFRs, Vol 3 - Thermal\Thermal Forced Outage\Carty.

Attachment 034-A is protected information subject to Protective Order No. 20-100.

### **UE 377**

## Attachment 033-A

## **Provided in Electronic Format**

### **Protected Information Subject to Protective Order 20-100**

Carty Availability Reports 2016, 2017, and January-May 2020

Page 18 of Exhibit AWEC/102 contains Protected Information Subject to Order No. 20-100 and has been redacted in its entirety.

June 23, 2020

TO:	Jesse O. Gorsuch
	Alliance of Western Energy Consumers

FROM: Jaki Ferchland Manager, Revenue Requirement

#### PORTLAND GENERAL ELECTRIC UE 377 PGE Response to AWEC Data Request No. 036 Dated June 9, 2020

#### <u>Request:</u>

Please refer to WUTC Docket No. UE-190882 - Final Order 05. If the response to DR 35 is no, please provide the following:

- a. The tests and communications related to the tests referenced in Par. 28, 33, 36, as well as any other tests performed by Talen related to MATS PM.
- b. Agenda, notes, presentations and all other data and documents related to the meetings referenced in Par. 29.
- c. All communications referenced in Par. 30, 32, 34,
- d. The root cause analysis and all related documents and communications identified in Par. 37.
- e. The O&O committee meeting minutes, attendee list, presentations, handouts, and all other materials related to Colstrip Owner and Operator committee meetings in 2018.
- f. All communication between PGE and Talen related to Colstrip MATS compliance in 2018.
- g. All actions taken by PGE in 2018 related to Colstrip MATS compliance and oversight of Talen.

#### <u>Response:</u>

PGE objects to this request on the basis that it is overly broad and unduly burdensome. Subject to and without waiving its objection PGE responds as follows:

Pursuant to a telephone and email communication, AWEC modified the data request to ask the following:

a. Confirm that Q1 2018 PM MATS testing for Colstrip showed a site-wide emissions rate of 0.030 lb/MMBtu. Also confirm that this represents the limit for the site. If PGE does not confirm these statements, please explain and provide all relevant documentation.

- b. Provide agenda, meeting minutes, presentations related to MATS PM testing, and any PGE notes related to MATS PM testing from the February 21, March 21, April 15, May 16, and June 20 committee meetings.
- c. AWEC withdrew this part.
- d. The root cause analysis and all related documents and communications identified in Par. 37.
- e. AWEC withdrew this part.
- f. Referring to paragraph 30 of WUTC Final Order 05, does PGE agree that the statements in this paragraph are accurate? If not, please explain what PGE believes is inaccurate and provide supporting documentation. If yes, please provide any communications PGE made to Talen in response to Talen's communications that it expected Colstrip to pass its Q2 MATS PM testing.

#### PGE responds as follows:

- a. PGE confirms that the 0.030 lb/MMBtu emission rate is the emissions limit for the Colstrip site. Attachment 036-A provides the Colstrip 2018 MATS 1<sup>st</sup> Semi-Annual Report. The Q1 2018 PM MATS testing results for all Colstrip Units are provided in Appendix D, starting on page 11. As reflected in Appendix D of the report, the Q1 2018 PM MATS testing resulted in an emission rate range from 0.021lb/MMBtu to 0.035 lb/MMBtu for Colstrip Units 1 through 4. Given the emission rates reported for each unit, the site-wide average emission rate for the Q1 2018 PM MATS testing appears to have been at 0.029 lb/MMBtu.
- b. Attachment 036-B provides meeting agendas and PGE notes from 2018 Colstrip owners meetings. Due to personnel retirement and turn-over, PGE was not able to locate the notes for the February 21, 2018 Colstrip owners meeting. Should PGE locate the February 21, 2018 notes, we will supplement the response to this data request and provide them as soon as possible.
- c. N/A
- d. Attachment 036-C provides the root cause analysis report. Please see PGE's response to AWEC Data Request No. 035, Attachment 035-A, which provides PGE's request that the plant operator and co-owners have an independent third-party facilitation of the Root Cause Analysis.
- e. N/A
- f. AWEC refers to the following paragraph in WUTC Docket No. UE-190882, Final Order 05:

"At times from February 14, 2018, to June 27, 2018, including at the O&O Committee Meetings between February 21 and June 20, 2018, Talen communicated to the Companies its expectation and recurring recommendation that Colstrip would pass its second quarterly (Q2) MATS PM Testing. This expectation was based upon observations of the CAM Plan's alternative and indicators and their historic correlation with PM emissions levels."

PGE cannot confirm the statements in the paragraph are accurate. PGE's notes from the Colstrip Units 3 and 4 owners meetings that took place between January and May, 2018 do not show any discussions that would confirm the statement. However, as noted above in part b, due to personnel retirement and turn-over PGE was not able to locate communications that would include PGE's notes from the February 21, 2018 owners meeting. According to PGE's notes provided in Attachment 036-B, the MATS testing was first discussed during the meeting that took place on June 20, 2018. During that meeting PGE requested that the plant operator ensure the accuracy of the testing and raised the coal quality issue.

Attachments 036-A through 036-C are protected information subject to Protective Order No. 20-100.

### UE 377

## Attachment 036-B

## **Provided in Electronic Format**

## **Protected Information Subject to Protective Order 20-100**

2018 Colstrip Owners Meeting Notes

Pages 23-48 of Exhibit AWEC/102 contain Protected Information Subject to Order No. 20-100 and have been redacted in their entirety.

May 28, 2020

Sabrinna Soldavini
Public Utility Commission of Oregon

FROM: Jaki Ferchland Manager, Revenue Requirement

#### PORTLAND GENERAL ELECTRIC UE 377 PGE Response to OPUC Data Request No. 004 Dated May 14, 2020

#### Request:

Please refer to PGE/100, Seulean – Kim – Batzler/22, which state "MONET does not assume any availability of non-firm delivered gas from December to February."

- a. Does PGE confirm this assumption matches with actual operations? That is, historically, has non-firm gas been delivered to the PW/Beaver complex in December through February?
- b. Please provide the amount of non-firm gas delivered to the PW/Beaver complex, by month in the years 2017, 2018, and 2019.

#### Response:

- a. Yes, PGE's assumption matches with actual operations. PGE does not assume non-firm delivered gas is available to supply at the PW/Beaver complex from December to February because historically PGE had very limited purchases of non-firm delivered gas in that period.
- b. Attachment 004-A provides the requested information. As reflected in Attachment 004-A, the non-firm gas purchased in the period December to February for the years 2017 to 2019 is only approximately 1.8% of total non-firm gas delivered at the PW/Beaver complex from January 1, 2017 to December 31, 2019.

Attachment 004-A is protected information subject to Protective Order No. 20-100.