Portland General Electric
121 SW Salmon Street · Portland, Ore. 97204
PortlandGeneral.com

September 7, 2018

Via e-mail
puc.filingcenter@state.or.us

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Ste. 100
P.O. Box 1088
Salem, OR 97301-1088

RE: UE 335 General Rate Case – PGE Surrebuttal Testimony

Filing Center,

Enclosed for filing in UE 335 are Surrebuttal Testimony and Exhibits of Portland General Electric Company (PGE). PGE will provide to the Filing Center an electronic copy of:

- PGE / 2600 Revenue Requirement (10 pages);
- PGE / 2601 2019 Revenue Requirement Base Business (3 pages);
- PGE / 2700 Transmission & Distribution (16 pages);
- PGE / 2800 Load Forecast (7 pages); and
- PGE / 2900 Pricing (16 pages).

In addition, the above will be posted to the UE 335 Huddle workspace. Because the filing is less than 100 pages, no physical copies will be provided.

If you have any questions, please call me at 503.464.7805. All formal correspondence and requests are to be directed to pge.opuc.filings@pgn.com.

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

SB:np

UE 335 / PGE / 2600
Tooman – Espinoza

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony and Exhibits of

Alex Tooman, Ph.D.
Marco Espinoza

September 7, 2018

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I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Alex Tooman. I am a Senior Regulatory Consultant for PGE.

My name is Marco Espinoza. I am a Senior Financial Analyst in the Rates and Regulatory Affairs department at PGE.

Our qualifications were previously provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to:

- Introduce the PGE exhibits that address the remaining unresolved issues in this proceeding;
- Summarize PGE's revised revenue requirement; and
- Address the one revenue requirement topic raised by the Oregon Citizen's Utility Board (CUB) in rebuttal testimony.

Q. What is the status of the revenue requirement issues in this proceeding?

A. PGE, the Staff of the Public Utility Commission of Oregon (Staff), and other parties have reached agreement on all revenue requirement and power cost issues in this proceeding. We summarize the impact of these agreements in Section II, below.

Q. What other exhibits is PGE submitting as part of its surrebuttal testimony?

A. In addition to this testimony, the following PGE exhibits respond to the unresolved issues raised by other parties and discussed in their rebuttal testimony:

- 2700 – Transmission and Distribution;
- 2800 – Load Forecast; and
- 2900 – Pricing.

Q. How is the remainder of your testimony organized?

A. After this introduction, we summarize PGE's revised revenue requirement based on all the settlements as well as scheduled updates to date. We then address the matter raised by the CUB regarding the unbundling of PGE's smart grid investments.

II. Updated Revenue Requirement

Q. Please describe the settlements that have been reached in this proceeding.

A. PGE and other parties have entered into several settlements in this proceeding, which we summarize as follows:

- May 18 settlement resolved several non-power cost issues, including cost of capital, raised by parties prior to the filing of their opening testimonies. A stipulation reflecting this first partial settlement was filed on August 17.
- June 19 settlement resolved several non-power cost issues raised by parties in their opening testimony. A stipulation reflecting this second partial settlement was filed on August 29.
- June 29 settlement resolved all power cost issues raised by parties in this proceeding. A stipulation reflecting this settlement was filed on August 22.
- July 24 settlement resolved all remaining non-power cost, revenue requirement issues raised by parties in their opening testimony along with certain pricing and load forecast issues. A stipulation reflecting this third partial settlement was filed on September 6. Consequently, the current revenue requirement as summarized below, includes the impacts of this settlement.
- August 10 settlement among certain parties addressed the direct access issues in this proceeding. Because other parties are expected to contest this partial settlement, however, direct access has been bifurcated to a separate schedule and is not addressed in PGE's surrebuttal testimony. A stipulation reflecting the direct access settlement was filed on August 20.

Q. Has PGE included the effects of scheduled updates in its revenue requirement?

A. Yes. In accordance with the schedule established on March 20, 2018, PGE updated its initial power cost forecast on March 30 and July 6, 2018. PGE also updated its load forecast in June as described in PGE Exhibit 1100.

Q. What is the impact of these settlements and updates?

A. Based on all settlements and updates to date, PGE's revenue requirement for the 2019 test year currently totals $1,851.8 million, which represents a $33.5 million increase in revenue or a 1.84% overall increase in prices (see PGE Exhibit 2601 and work papers in support of this testimony). This compares to the $1,884.6 million revenue requirement submitted as part of PGE's initial filing, which reflected an $85.9 million increase in revenue or a 4.78% overall increase in prices.

Q. Would this be the final revenue requirement in this case pending Commission adoption of the stipulations?

A. No. There are several additional updates to be performed before the revenue requirement is final in this case even assuming the Commission adopts all the stipulations as part of its order(s).

Q. Please summarize the remaining updates.

A. There are three categories of updates:

- Pension expense will be updated in accordance with the third partial stipulation, which specifies that PGE will update the pension discount rate on September 4, 2018, using a two-week average rate in the Willis Towers Watson pension tool.
- Power costs will be updated in accordance with the schedule established on March 20, 2018, which specifies the following remaining updates:

  - September 28, 2018
  - November 6, 2018
  - November 15, 2018
- Load forecast will be updated in September 2018 in accordance with PGE Exhibit 1100. This update will further impact the September 28th power cost forecast.

III. Unbundling Smart Grid Investment

Q. Please summarize CUB's issue regarding PGE's smart grid investments.

A. CUB has expressed concerns regarding the functionalization (i.e., unbundling) of PGE's smart grid investments and states that "Increasingly, PGE is making investments in its distribution system, which provides [*sic*] both capacity and energy resources."[1]

Q. Does CUB make any specific recommendations?

A. Yes. CUB requests that PGE "have a third party look at the costs in a specific set of FERC accounts that represent where smart grid investments will reside and make recommendations as to the approaches of functionalization that would better align those investments with their expected functions."[2]

Q. How do you respond to CUB's proposal?

A. We believe that unbundling PGE's costs accurately is an important goal. To that end, we are willing to work with CUB, Staff, and any other interested parties to address this issue. As primary considerations, we believe that the parties would need to:

- Define smart grid for this context.
- Identify possible third-party experts that could assist in this process and evaluate the basis of their contribution.
- Review the current parameters used to functionalize specific assets and discuss how those might change under CUB's proposal. For example, CUB's quote above specifically references investments in the <u>distribution</u> system, which provide both

[1] CUB/300, page 12.
[2] Ibid.

capacity and energy resources. The types of issues that would need to be resolved include:

- To what functional area(s) are those assets currently assigned or allocated and why?
- What would be the basis for re-assigning all the costs or re-allocating some of the costs to different functional areas? In other words, to what degree does the asset directly provide the alternative function or indirectly support the alternative function and does this justify a re-assignment or re-allocation?

Q. Has PGE made any adjustments to date to address CUB's concern?

A. Yes. Along with adjustments to PGE's revenue requirement reflected in the stipulations listed above, PGE revised its functionalization of the Customer Touchpoints project to allocate 10% of the costs to generation based on the detail provided in CUB Exhibit 200. We believe that this is an interim determination. The suggested study/analysis referenced above should also include these costs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2601	Updated Revenue Requirement

Portland General Electric Company
2019 Revenue Requirement - Base Business
($000)

	Rev Req	Percent
Total Increase:	33,516	1.84%

	At Current Rates	July Load Forecast Delta	GRC Change for RROE	Proposed 2018	Non-NVPC Adjustments	NVPC Adjustments	Total Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1 Sales to Consumers	1,798,713	19,582	66,326	1,884,622	(36,839)	4,029	1,851,812
2 Sales for Resale	-			-	-	-	-
3 Other Revenues	25,327			25,327	-	-	25,327
4 Total Operating Revenues	1,824,041		66,326	1,909,949	(36,839)	4,029	1,877,140
5 Net Variable Power Costs	375,309			375,309	-	3,887	379,196
6 Production O&M (excludes Trojan)	165,665			165,665	(1,652)	-	164,013
7 Trojan O&M	115			115	-	-	115
8 Transmission O&M	15,798			15,798	-	-	15,798
9 Distribution O&M	136,180			136,180	(858)	-	135,321
10 Customer & MBC O&M	78,739			78,739	(2,400)	-	76,339
11 Uncollectibles Expense	6,171		295	6,466	(120)	13	6,043
12 OPUC Fees	5,776		276	6,052	(118)	13	5,946
13 A&G, Ins/Bene., & Gen. Plant	174,655			174,655	(14,168)	-	160,486
14 Total Operating & Maintenance	958,407		571	958,978	(19,317)	3,913	943,259
15 Depreciation	305,531			305,531	(2,962)	-	302,569
16 Amortization	66,965			66,965	(500)	-	66,465
17 Property Tax	71,578			71,578	-	-	71,578
18 Payroll Tax	16,637			16,637	-	-	16,637
19 Other Taxes	2,501			2,501	-	-	2,501
20 Franchise Fees	45,644		2,180	47,825	(935)	102	46,992
21 Utility Income Tax	62,226		22,571	84,797	(3,923)	3	80,588
22 Total Operating Expenses & Taxes	1,529,491		25,322	1,554,812	(27,637)	4,018	1,530,589
23 **Utility Operating Income**	294,550		60,586	355,137	(9,202)	11	346,550
				355,137			346,550

24 **Average Rate Base**						
25 Avg. Gross Plant	10,221,818		10,221,818	(74,050)	-	10,147,768
26 Avg. Accum. Deprec. / Amort	(4,761,822)		(4,761,822)	(19,800)	-	(4,781,622)
27 Avg. Accum. Def Tax	(679,665)		(679,665)	(6,187)	-	(685,852)
28 Avg. Accum. Def ITC	-		-	-	-	-
29 **Avg. Net Utility Plant**	4,780,331	-	4,780,331	(100,037)	-	4,680,294
30 Misc. Deferred Debits	9,294		9,294	-	-	9,294
31 Operating Materials & Fuel	78,945		78,945	-	-	78,945
32 Misc. Deferred Credits	(74,554)		(74,554)	(5,289)	-	(79,843)
33 Working Cash	62,143	1,029	63,172	(1,058)	154	58,576
34 **Average Rate Base**	4,856,160	1,029	4,857,189	(106,384)	154	4,747,266
35 **Rate of Return**	6.065%		7.312%		7.300%	7.300%
36 **Implied Return on Equity**	7.008%		9.500%		9.500%	9.500%
37 Effective Cost of Debt	5.123%	5.123%	5.123%	5.100%	5.100%	5.100%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.562%	2.562%	2.562%	2.550%	2.550%	2.550%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.786%	7.786%	7.786%	7.580%	7.580%	7.580%
45 Federal Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%
46 Composite Tax Rate	27.151%	27.151%	27.151%	26.988%	26.988%	26.988%
47 Bad Debt Rate	0.343%	0.343%	0.343%	0.326%	0.326%	0.326%
48 Franchise Fee Rate	2.538%	2.538%	2.538%	2.538%	2.538%	2.538%
49 Working Cash Factor	4.063%	4.063%	4.063%	3.827%	3.827%	3.827%
50 Gross-Up Factor	1.373	1.373	1.373	1.370	1.370	1.370
51 ROE Target	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%
52 Grossed-Up COC	9.082%	9.082%	9.082%	9.056%	9.056%	9.056%
53 OPUC Fee Rate	0.321%	0.321%	0.321%	0.321%	0.321%	0.321%

	Utility Income Taxes						
54	Book Revenues	1,824,041	85,908	1,909,949	(36,839)	4,029	1,877,140
55	Book Expenses	1,467,265	2,751	1,470,015	(23,714)	4,016	1,450,001
56	Interest Deduction	124,394	26	124,420	(2,713)	4	121,055
57	Production Deduction	-		-	-		-
58	Permanent Ms	(22,619)		(22,619)	-		(22,619)
59	Deferred Ms	63,378		63,378	-		63,378
60	Taxable Income	191,623	83,131	274,755	(10,412)	10	265,324
61	Current State Tax	14,921	6,473	21,394	(789)	1	20,112
62	State Tax Credits	-		-	(10)		(10)
63	Net State Taxes	14,921	6,473	21,394	(799)	1	20,102
64	Federal Taxable Income	176,703	76,658	253,361	(9,613)	9	245,222
65	Current Federal Tax	37,108	16,098	53,206	(2,019)	2	51,497
66	Federal Tax Credits	-		-	-		-
67	Excess ADIT Reversal (ARAM)	(7,010)	-	(7,010)	(1,105)		(8,115)
68	Deferred Taxes	17,208	0	17,208	-	-	17,105
69	Total Income Tax Expense	62,226	22,571	84,797	(3,923)	3	80,588
70	Regulated Net Income	170,156		230,716			225,495
71	Check Regulated NI			230,716			225,495

UE 335 / PGE / 2700
Nicholson – Bekkedahl

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Transmission & Distribution

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony and Exhibits of

Bill Nicholson
Larry Bekkedahl

September 7, 2018

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I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Bill Nicholson. I am the Senior Vice President of Transmission and Distribution (T&D).

My name is Larry Bekkedahl. I am the Vice President of Transmission and Distribution. Our qualifications appear in PGE Exhibit 800, Section VI.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide support for PGE's proposal to modify the Level III storm accrual mechanism to allow negative as well as positive balances.[1] In particular, we discuss how this proposal allows PGE to recover prudently incurred costs associated with quickly restoring power for our customers and to manage customer price impacts by normalizing the irregular nature of Level III storm restoration costs. PGE incurs these costs to best serve our customers and to ensure that our customers' service is back on-line as soon as possible; thus, these costs should be recoverable from customers.

Q. Do other utilities have approved balancing accounts for storm costs?

A. Yes. Many other utilities have storm recovery mechanisms similar to PGE's proposed mechanism. For example, Alabama Power,[2] Entergy Arkansas,[3] and Pacific Gas and Electric

[1] We use the term "balancing account" to describe this accounting treatment in this testimony. See PGE Exhibit 800, page 14, line 19 through page 15, line 5, for additional information.
[2] By Order dated December 6, 2005 in Docket No. U-3556, the Alabama Commission approved Alabama Power's request to record O&M expenses associated with natural disasters in their Natural Disaster Reserve (established in 1994), even when expenses cause a negative balance in the account.
[3] Order No. 3 in Docket No. 09-031-U, pursuant to Arkansas statute, approved Entergy Arkansas' request to establish a storm reserve account and allow a debit balance. Entergy Arkansas must file quarterly reports identifying instances in which they recorded costs in the storm reserve for the Arkansas Commission to audit, analyze, examine, and adjust these costs for reasonableness and prudency.

Company (PG&E)[4] are examples of investor-owned utilities that receive this type of accounting treatment from their regulators. Thus, PGE's proposal intends to bring PGE into alignment with other utilities and their storm cost recovery mechanisms.

Q. Please summarize Parties'[5] concerns regarding PGE's proposal and PGE's response to those concerns.

A. Parties raise four primary concerns regarding PGE's proposal:

1. The existing Level III storm mechanism[6] should not be modified because:
   - Storm restoration costs represent stochastic risk and the Commission previously reasoned that stochastic risks that are modeled in rates represent "reasonable risk" that the Company assumes as part of the normal course of utility operations[7];
   - The under-collection in some years is offset by over-collection in other years so that "Overall, the cost recovery balances out to provide the utility a reasonable level of recovery"[8]; and
   - PGE has existing "mechanisms [e.g., a deferral] to reduce its risk in high storm cost years."[9]

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[4] Decision 14-08-032 in Docket No. 14-08-031 approved PG&E's request for a Major Emergency Balancing Account (MEBA). The MEBA is a two-way balancing account that records and recovers actual expenses and capital revenue requirements resulting from catastrophic events that are not declared a state of emergency.
[5] The "Parties" collectively refer to the Public Utility Commission of Oregon (OPUC) Staff, the Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens' Utility Board (CUB).
[6] Per Order 10-478, PGE collected $2.0 million annually to pay for service restoration following Level III storms. The annual accrual is based on a rolling ten-year average of Level III storm cost, adjusted to reflect present value costs. PGE currently collects $2.6 million for use against future Level III storms based on the rolling ten-year average of Level III storm costs from 2007-2016 (per Order No. 17-511 in UE 319).
[7] Staff/700, page 5, line 2.
[8] AWEC/400, page 2, lines 13-14.
[9] CUB/200, page 27, line 7.

In response, we note that PGE faces unreasonable risk resulting from the inability to recover storm restoration costs incurred to provide service to our customers during and after Level III storms;

2. The disincentive for PGE to prudently manage Level III storm costs under a balancing account mechanism. However, this concern was addressed in PGE Exhibit 800, page 15, where we detail how PGE's proposed balancing account mechanism would authorize customers to pay for the appropriate level of Level III storm costs, as determined by a prudence review and/or audit by Staff;
3. Unnecessary rate fluctuations resulting from PGE's proposed balancing account. In response, we note that when put into proper perspective, PGE's proposal provides the benefit of managing customer price impacts by normalizing the irregular nature of Level III restoration costs for the purpose of establishing customer prices; and
4. PGE's proposal not being fully developed. In response, we reiterate and provide clarity on how PGE's proposed modification to the Level III storm accrual would function in Section II below.

II. PGE's Response to Parties' Concerns

Q. What are Parties' concerns regarding PGE's proposal to make the Level III storm accrual a balancing account?

A. As noted above, Parties raise four primary concerns regarding PGE's proposal:

1. The existing Level III storm accrual mechanism should not be modified;
2. There would be a disincentive for PGE to prudently manage storm costs under a balancing account mechanism;
3. There would be unnecessary rate fluctuations resulting from PGE's proposal; and
4. PGE's proposal is not fully developed.

We address each concern in detail below.

1. Response to Parties' Views of Not Changing the Existing Storm Mechanism

Q. How do you respond to Parties' views regarding PGE's existing Level III storm mechanism?

A. Parties believe that the existing Level III storm mechanism is adequate and should not be modified. However, these views are based on misunderstandings or otherwise not supported.

Q. Your introduction listed three reasons why the Parties believe the current mechanism should not be modified. What is the first reason?

A. Staff is concerned that "the Commission has previously reasoned that stochastic risks that are modeled in rates represent reasonable risk that the Company assumes as part of the normal course of utility operations."[10]

[10] Staff/1100, page 4, line 22, through page 5, line 3.

Q. Does Staff provide any quantitative measure of stochastic risk?

A. No. Staff only hints at the possible limits in their opening testimony. There, Staff references a Commission decision from 2004 related specifically to net variable power costs (NVPC) wherein 250 basis points of return on equity (ROE) was established as a deadband.[11]

Q. How much is 250 basis points of ROE for PGE?

A. Based on our approved revenue requirement from PGE's last general rate case (UE 319 – 2018 test year), 250 basis points of ROE amounts to approximately $100 million. Although Staff acknowledges that "the threshold for deferral of storm costs may not be as large as what it is for deferral of NVPC,"[12] they note that "the 2017 storm costs represent an amount equal to approximately 47 basis points of … ROE"[13] and that this is "well below what the Commission has indicated represents reasonable risk for utilities between rate cases."[14]

Q. Did Staff provide any references for what the Commission has indicated as reasonable risk?

A. No. Staff only suggests that 47 basis points is too little and that 250 basis points or $100 million is likely an upper end.[15] By labeling storm costs as stochastic and suggesting that such thresholds apply, Staff can effectively assert that any level of storm costs falls within normal business risk. This means that a particularly severe storm or a series of severe storms that impose extraordinary costs on PGE will never be viewed as extraordinary. Thus, the existing mechanism is adequate for only a certain level of storm costs, but fails to address the extraordinary storm costs that can and do occur.

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[11] Staff/700, page 6, lines 4-8.
[12] Staff/700, page 6, lines 8-9.
[13] Ibid., lines 9-11.
[14] Ibid., lines 11-12.
[15] Since 2004, the Commission has approved much lower deadbands for PGE's power cost adjustment mechanism. The current deadbands are $30 million for a positive variance and $15 million for negative variance.

Q. What is the second reason that the Parties believe the current mechanism should not be modified?

A. AWEC argues that PGE is provided with the opportunity to recover high Level III storm costs in any particular year "through an increase in the [ten-year] rolling average,"[16] which "provide[s] the utility with full recovery for the costs incurred in that year."[17] Table 1, below, demonstrates that an increase in the ten-year rolling average does not necessarily provide PGE with full recovery for the costs incurred in a given year. Although years with relatively high Level III storm costs remain in the ten-year average calculation, Table 1[18] shows that PGE is not "provide[d]…with full recovery for the costs incurred in that year."[19] In fact, a storm accrual balancing account would have been negative for the past three years (i.e., 2015-2017). In addition, as detailed in PGE Exhibit 2101, based on actual storm restoration activity since 1995, and assuming a similar mechanism was initiated any year beginning after 2004 (i.e., to allow at least ten years of actual detail to inform the rolling average), most years would result in a negative storm accrual balance.

Table 1
Storm Accrual Collection

Year	Collection	Withdrawals	Balance
2011	$2.0 million	$0.0 million	$2.0 million
2012	$2.0 million	$0.0 million	$4.0 million
2013	$2.0 million	$0.0 million	$6.0 million
2014	$2.0 million	$5.6 million	$2.4 million
2015	$2.0 million	$5.1 million	($0.8 million)
2016	$2.0 million	$4.5 million	($3.3 million)
2017	$2.0 million	$11.4 million	($12.6 million)

[16] AWEC/200, page 49, line 20.
[17] AWEC/200, page 49, line 22.
[18] Table 1 starts with 2011, which is when the current accrual mechanism began pursuant to Commission Order No. 10-478.
[19] Ibid.

Q. Does AWEC believe that the collections and withdrawals balance out over time?

A. Yes. In spite of this evidence, AWEC mistakenly claims that the over-collection of storm restoration costs in some years will offset the under-collection in other years, noting that "Overall, the cost recovery, using this method, balances out to provide the utility with a reasonable level of recovery."[20]

Q. Does AWEC draw any other incorrect conclusions from the historical evidence?

A. Yes. AWEC also incorrectly notes that "The need for a storm balancing account such as this cannot be reasonably established by simply pointing to a single year when the actual costs exceeded the average, and summarily concluding that an extraordinary ratemaking mechanism is necessary."[21] Although 2017 entailed particularly severe weather, it was not an isolated event or solely the basis of PGE's proposal. Instead, 2017 was the fourth consecutive year of significant Level III events and the net impact of collections and withdrawals would already have been negative, even with the benefit of the 2017 collection. In summary, Table 1 clearly shows that over time, the absence of a balancing account means that years of under-collection are not equally offset by years of over-collection.

Q. What is the third reason that the Parties believe the current mechanism should not be modified?

A. CUB observes that PGE can file for deferrals in high storm cost years. CUB further states that PGE's proposal is unreasonable since "[PGE] already has mechanisms to reduce its risk in high cost storm years."[22] However, the fact that PGE can file for a deferral in high cost storm years does not indicate that the deferral request will be approved or that PGE will

[20] AWEC/400, page 2, line 13-14.
[21] AWEC/400, page 2, line 21, through page 3, line 2.
[22] CUB/200, page 27, lines 6-7.

receive recovery of those costs. For instance, parties have recommended that the Commission deny PGE's application for 2017 Level III storm costs (Staff Exhibit 700, AWEC Exhibit 400, and CUB Exhibit 200). In short, one party states that PGE has the option to file for deferred accounting to address high storm costs, while other parties preclude that option based on the stochastic nature of those costs.

2. Response to Parties' Concerns of Prudently Managing Storm Restoration Costs Under a Balancing Account Mechanism

Q. What are Parties' concerns regarding PGE's management of storm costs under a balancing account mechanism?

A. Staff states that "having a policy that guarantees full recovery of storm-related costs provides no incentive for PGE to prudently manage those costs."[23] In line with this view, CUB also asserts that PGE does not have the incentive to control Level III storm restoration costs under a balancing account between rate cases.[24]

Q. How would Staff evaluate PGE's Level III storm restoration costs under the proposed balancing account?

A. Staff can conduct prudence reviews and/or audits at any time to ensure that customers pay for appropriate costs included in PGE's storm accrual, as discussed in PGE Exhibit 800[25] and PGE Exhibit 2100.[26] Thus, PGE has a strong incentive to prudently manage storm-related costs under a balancing account mechanism. In fact, the existing mechanism would theoretically seem to create a disincentive for a utility to restore power as quickly as possible. Using CUB's reasoning, if cost recovery is precluded due to a depleted storm reserve and no

[23] Staff/700, page 7, lines 3-4.
[24] CUB/300, page 14, lines 10-16.
[25] PGE/800, page 15, lines 3-4.
[26] PGE/2100, page 12, line 20 through page 13, line 2.

possibility for deferred accounting, a financially struggling utility could be inclined to less diligently restore customers' power to lower its costs. PGE would not do this, and neither would we succumb to an imagined incentive to imprudently manage storm restoration costs based on the existence of a balancing account.

Q. Do Parties provide a definition or information on what it means to prudently manage Level III storm restoration costs?

A. No. Parties do not provide a definition or information of what it means to prudently manage storm costs. The only indication is CUB's rebuttal testimony, where they reference PGE's example[27] of traffic gridlock during Level III storm events causing increasing labor costs. Curiously, CUB provides no further explanation of how this reference supports their assertion that PGE is disincentivized to control Level III storm costs under a balancing account mechanism or how this in some way shows that PGE is imprudently incurring Level III storm costs. Instead, we are left with a vague reference about storm conditions, which are beyond PGE's control, followed by CUB's definitive conclusion about PGE's disincentive to manage costs. We are baffled by this *non-sequitur*.

Q. How do you respond to CUB's characterization of the referenced costs?

A. While we actively manage our costs associated with restoring power to our customers, as detailed in PGE Exhibit 800,[28] the conditions under which we incur those costs are due to events that are beyond PGE's control, such as road conditions and traffic during or following Level III storms. PGE's incentive is to restore power to customers as quickly as possible. CUB's argument has no logic or support.

[27] PGE/800, page 14, lines 8-9.
[28] PGE/800, page 14, lines 4-11.

3. Response to AWEC's Concern of Increased Rate Fluctuations Resulting from PGE's Proposal

Q. Please summarize AWEC's concern regarding unnecessary rate fluctuations resulting from PGE's proposed balancing account.

A. AWEC incorrectly asserts that PGE's proposal would result in "unnecessary rate fluctuations"[29] that will not "better match the costs and benefits to ratepayers."[30] AWEC also asserts that "transitioning to dollar-for-dollar tracking will not result in any better matching between costs and benefits."[31]

Q. How do you respond to AWEC's position regarding greater rate fluctuation?

A. We have significant reservations about AWEC's position because it seems that AWEC may be misinterpreting how PGE's proposed balancing account would function. If PGE's proposed balancing account is approved, the ten-year rolling average for Level III storm costs would continue to inform the accrual collection. Thus, the collection for the balancing account only allows for "incremental changes to the accrual level"[32] based on the ten-year rolling average. This ensures that customers contribute a relatively consistent amount each year for use towards service restoration costs following Level III storms. The approval of a balancing account would not introduce greater fluctuation in the mechanism.

Q. How do you respond to AWEC's assertion regarding dollar-for-dollar tracking?

A. AWEC's assertion is particularly indicative of Parties' lack of understanding of the proposed balancing account, which would in no way reflect dollar-for-dollar tracking. AWEC's specific concern is that it would be inequitable for customers to bear the costs of a particular storm just because they "happen to be customers of the Company in the particular year when

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[29] AWEC/400, page 4, line 15.
[30] AWEC/400, page 4, lines 8-9.
[31] AWEC/400, page 4, lines 17-18.
[32] AWEC/400, page 3, line 22.

the large storm occurred."[33] In fact, the proposed balancing account would achieve the opposite of such an outcome, because it would continue to rely on ten-year rolling averages to determine cost recovery and is intended to smooth "the impact of storm costs on customer prices by normalizing those costs over time."[34]

4. Response to AWEC's Concern that PGE's Proposal is Not Fully Developed

Q. AWEC states that your proposal is not fully developed.[35] Can you provide some additional details on your proposal?

A. Certainly. PGE proposes to continue collecting for costs attributed to Level III storms, but if the actual Level III storm costs exceed the amount collected from customers, the account balance of accrued funds could become negative. The mechanism would continue, and the negative balance would be offset in subsequent years when damage from Level III storms was less than the accrual amount. Under this accounting treatment, PGE could recover prudently incurred storm costs while occasionally carrying a negative balance in the storm account.

Q. Has the Commission ever approved a similar accounting treatment for PGE?

A. Yes. The proposed Level III storm accrual has similar accounting treatment to the major maintenance accruals (MMAs) approved for several of PGE's thermal generation facilities.[36] The MMAs also fluctuate between positive and negative balances as the accrual grows and costs offset the accrual.

[33] AWEC/400, page 4, lines 14-15.
[34] PGE/800, page 15, lines 4-5.
[35] AWEC/400, page 3, lines 17-18.
[36] Coyote Springs, UE-93, PGE Exhibit 600. Port Westward 1, UE 262, PGE Exhibit 300. Port Westward 2, UE 283, PGE Exhibit 300. Carty, UE 294, PGE Exhibit 300.

Q. How will PGE adjust the accrual collection?

A. PGE could either: 1) adjust the Level III storm accrual rate based on the ten-year rolling average; or 2) use a supplemental schedule to adjust the Level III storm accrual rate. PGE would rather adjust the accrual collection based on the ten-year rolling average and retain the accrued amount as a reserve to be used toward future Level III storm costs. Therefore, if the balancing account is consistently positive over time, a decrease in the reserve accrual would be appropriate.

III. Summary and Conclusions

Q. Please summarize PGE's surrebuttal testimony.

Q. Parties have addressed a number of concerns regarding PGE's proposal for the Level III storm accrual modification and all have recommended against Commission approval. We acknowledge the concerns expressed by parties regarding our request and understand the basis for those concerns. In this surrebuttal testimony, however, we have shown that when put in proper perspective, those concerns have no merit. We identify certain primary points regarding Parties' concerns below:

- PGE is limited in recovering prudently incurred costs from serving our customers during and following Level III storms; and
- PGE's proposed Level III storm balancing account would authorize customers to pay for appropriate storm costs, as determined by a prudence review and/or audit and smooths the impact of Level III storm costs on customer prices by normalizing those costs over time.

Q. What, specifically, do you request of the Commission?

A. We request that the Commission approve our proposal to allow PGE's Level III storm accrual to have negative as well as positive balances similar to the approved balancing accounts that PGE uses for MMAs for several of our thermal generating plants. We believe that the proposed balancing account as described here and in PGE Exhibits 800 and 2100, is appropriate because it provides PGE recovery of prudently incurred costs to restore service to our customers, as quickly as possible, during and after Level III storm events. If the Commission were to not approve the storm restoration balancing account as proposed, we have two follow-up requests:

- That the Commission provide guidance as to the type of cost recovery it believes would be appropriate for PGE's storm restoration costs; and
- That the Commission direct PGE and Parties to begin discussions to formulate a mechanism that addresses the Commission's guidelines.

Q. Is PGE willing to discuss alternative balancing account approaches with Parties?

A. Yes. PGE has been and continues to be willing to discuss alternative balancing account approaches with Parties.

Q. Does this conclude your testimony?

A. Yes.

UE 335 / PGE / 2800
Riter – Lucas

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony and Exhibits of

Amber Riter
Alison Lucas

September 7, 2018

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I. Introduction

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Amber M. Riter. I am an Economist and the Lead Load Forecasting Analyst at PGE.

My name is Alison Lucas. I am a Load Forecasting Analyst at PGE.

We are responsible for developing PGE's energy deliveries forecast. Our qualifications appear in PGE/1100.

Q. What is the purpose of your testimony?

A. This testimony responds to the Rebuttal testimony of Public Utility Commission of Oregon Staff (Staff) provided in Staff Exhibit 1200 on the subject of PGE's load forecast normal weather assumption.

Q. What is PGE's recommendation for the 2019 test year forecast?

A. PGE recommends that the Commission adopt the trended weather approach for the normal weather assumption to replace the 15-year historical average assumption.

Q. What load forecast recommendation does Staff make?

A. Staff proposes no change from PGE's prior weather assumption (a 15-year historical average), recommending against adoption of the trended weather assumption. Staff's recommendation would result in an increase of 48 thousand MWh compared to the 2019 test year forecast presented in PGE's rebuttal testimony.

II. Trended Weather Assumption

Q. Why does PGE propose using a trended weather assumption for the normal weather assumption?

A. Scientists around the world, and specifically at National Aeronautics and Space Administration (NASA) and National Oceanic and Atmospheric Administration (NOAA), point to the rise of global temperatures[1,2] as evidence of climate change, and in fact, PGE observes a warming trend in cooling degree days (CDD) and heating degree days (HDD) in its service area. PGE proposes this change to its normal weather assumption for its forecast to recognize impacts of climate change and capture the "50/50" (i.e., 50 percent chance the actual outcome falls short and 50 percent the actual outcome exceeds) normal weather assumption for a future period, whether that is one year ahead or 20 years ahead.

The trended weather methodology PGE proposes moves the normal weather assumption from a historical view to a forward-looking view.

Q. Why is Staff opposed to the trended weather assumption?

A. Staff rejects the trended weather assumption due to the perceived complexity of the approach and lack of precedent by other commissions.

Q. Does PGE agree that the trended weather assumption adds complexity?

A. No, the trended weather assumption does not add complexity. Trended weather involves applying a linear fit, which means multiplying by the slope and then adding the offset. It is easy to implement and straightforward to describe.

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[1] https://climate.nasa.gov/evidence/.
[2] https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature.

Q. What is the precedent for utilities using a load forecast based on a trended weather assumption in General Rate Cases (GRCs)?

A. PGE is aware of at least five GRC dockets[3,4,5,6,7] in five different states filed using or discussing the validity of trended weather. While none outright accepted the adoption of trended weather in final settlements, in many, Commission Staff remained agnostic to its usage or settled without releasing a response on the matter.

Staff's reliance on the fact that other commissions have not yet adopted this type of approach is not an assessment of the reasonableness of the approach.

Q. Is there non-utility precedent for using a trended weather assumption in electric demand forecasting?

A. Yes. United States (US) governmental agencies have used a trended weather assumption for electric demand forecasting. While Staff states that the approach "has been studied and otherwise is available as a means of making sample forecasts to further knowledge by different governmental agencies", it disregards the fact that the US Energy Information Association has in fact included a linear trend in CDD and HDD in its base case forecast for the 2018 Annual

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[3] Black Hills/Colorado Gas Utility Company filed a GRC with the Colorado Public Utilities Commission in 2008 (docket 08S-290G) using the trended ("hinge-fit") normal weather assumption. A settlement was ultimately reached that adjusted the NOAA 30-year normal.
[4] Missouri Gas Energy filed a GRC with the Missouri Public Service Commission in 2009 (docket GR-2009-0355) using the trended normal weather assumption. PGE is not aware of the result of this docket.
[5] Black Hills/Nebraska Gas Utility Company used discussion of the trended normal weather assumption to justify changing its normal weather assumption from a 30-year rolling average to 10-year rolling average in its GRC filed with the Nebraska Public Service Commission in 2009 (docket NG-0061). A 10-year rolling average was adopted.
[6] Michigan Consolidated Gas Company filed a GRC with the Michigan Public Service Commission in 2010 (docket U-15985) in which it used the trended normal weather assumption in its load forecast. Although the method won the support of the administrative law judge, the Commission ultimately ordered the adoption of a 15-year rolling average normal weather assumption rather than a 30-year rolling average.
[7] CenterPoint Energy Resources filed GRCs in 2013 and 2015 with the Minnesota Public Utilities Commission (Dockets G-008/13-316 and G-008/GR-15-424) using discussion of the trended normal weather assumption to support use of a 10-year rolling average normal weather assumption rather than a 20-year rolling average normal weather assumption. The 10-year rolling average was adopted.

Energy Outlook,[8] and this report is the US government's official energy demand forecast used for policy making.

Q. Could PGE use trended weather in its long-term forecasts while maintaining the 15-year rolling average in its short-term forecast for the 2019 future test year?

A. PGE maintains consistency in its normal weather assumption across all forecast horizons. That is, the same normal weather assumption is used for the short-term GRC forecast and the long-term Integrated Resource Plan forecast.

In Staff Exhibit 1200, Staff says the GRC and IRP "have differing goals and the forecast methodologies should cater to those goals." PGE does not agree with this statement as it pertains to input assumptions. Consistent assumptions across base case forecasts are appropriate for symmetry across planning functions. PGE's planning functions do not live in isolation, and the representation of what is expected next year should be internally consistent with what is expected in 2, 5, or 20 years.

PGE sees no reason that the approach, which captures gradual warming over time, would be appropriate for one forecast and not the other. The gradual warming changes not only PGE's total expected energy deliveries but also the seasonal shape of those deliveries, such that more electricity is consumed in summer months and less in winter months, and it is important to capture these impacts over all forecast horizons.

Q. What does PGE ask of the Commission?

A. PGE requests the Commission accept its trended weather methodology for the normal weather assumption in its load forecast.

[8] https://www.eia.gov/outlooks/aeo/, https://www.eia.gov/outlooks/aeo/assumptions/pdf/residential.pdf , p31.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony and Exhibits of

Robert Macfarlane
Jacob Goodspeed

September 7, 2018

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I. Introduction

Q. Please state your name and position with Portland General Electric Company (PGE).

A. My name is Robert Macfarlane. I am a Regulatory Consultant in Pricing and Tariffs.

My name is Jacob Goodspeed. I am a Regulatory Consultant in Pricing and Tariffs.

Our qualifications were previously provided in PGE Exhibit 1200.

Q. What is the purpose of this testimony?

A. We provide an update of the overall rate impacts and the impacts to various PGE rate schedules consistent with the testimony in PGE Exhibit 2600. We also address the following issues raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) in Staff Exhibits 1100, the Alliance of Western Energy Consumers (AWEC) in AWEC Exhibit 400, and the Oregon Citizen's Utility Board (CUB) in CUB Exhibit 300:

- Decoupling; and
- Schedule 122 (Renewable Resources Automatic Adjustment Clause).

Q. Please summarize the updated projected 2019 Cost of Service rate impacts.

A. Table 1, below, summarizes the base rate impacts effective January 1, 2019 for the major rate schedules.

Table 1
Estimated Cost of Service Rate Impacts

Schedule	Base Rates
Schedule 7 Residential	3.0%
Schedule 32 Small Nonresidential	3.8%
Schedule 83 31-200 kW	1.1%
Schedule 85 201-4,000 kW	-0.5%
Schedule 89 Over 4,000 kW	-0.5%
Schedule 90 100 MWa	-0.5%
COS & DA Overall	1.8%

II. Decoupling

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of testimony is to address the responses of Staff and CUB to PGE's decoupling proposal.

Q. Please summarize your proposal for changes to PGE's Schedule 123 Decoupling.

A. We proposed several substantive modifications to PGE's Schedule 123:

- Discontinue the Lost Revenue Recovery Adjustment (LRRA);
- Apply the Sales Normalization Adjustment (SNA) to Schedules 38/538, 47, and 49/549, and to the fixed generation portion of the volumetric generation charges in Schedules 83 and 85;
- Remove the weather (normalizing) adjustment from the SNA to allow the full differences in use per customer to be refunded to customers or charged to customers; and
- Keep the 2% limiter but include the ability to carry forward any amounts over 2%, in a balancing account, to apply in subsequent year or years.

Q. In its testimony, CUB ties the success in energy efficiency since 2008 to PGE's decoupling mechanism. Does PGE agree with the inference that, without the decoupling mechanism, PGE would not support energy efficiency?

A. No. PGE's support for cost effective energy efficiency (EE) as the least cost, least risk resource pre-dates the current decoupling mechanism, Schedule 123, as evidenced by PGE's advocacy for expanded EE funding in Senate Bill (SB) 838 in 2007.

Q. Were parties to this docket supportive of PGE's proposed changes to Schedule 123 Decoupling?

A. No. Both CUB and Staff have opposed PGE's proposed changes. A summary of CUB's and Staff's opposition is as follows:

- CUB opposes the changes to the decoupling mechanism, calling the proposed changes a "risk shift" from PGE shareholders to customers with regard to weather variability. In testimony, CUB makes clear that they view a decoupling mechanism as a tool to remove disincentives to EE, and since that disincentive was removed in Oregon in 2008, CUB sees no further need to modify the decoupling adjustment in Oregon.
- Staff similarly expressed the view that the recommended changes represent a shift of risk from shareholders to customers, noting that these changes "do not advance Commission goals,"[1] and hypothetically do not provide a benefit to PGE customers.[2]

Q. Does PGE agree with the assessment of CUB and Staff that decoupling is useful only for conservation efforts?

A. No.

Q. Broadly speaking, what is the benefit of including weather variations in decoupling?

A. Including weather variations in a utility's decoupling mechanism fully removes the throughput yield incentive that otherwise exists in traditional ratemaking, where a utility

[1] Staff Exhibit 1100, page 4.
[2] Staff Exhibit 1100, page 6.

needs to promote the sale of kWhs to fully recover fixed costs.[3] Where removing the disincentive to invest in energy efficiency was the original goal of Oregon's decoupling mechanism (and indeed removed a portion of the throughput yield incentive), removing weather variability fully de-links the recovery of fixed costs from volumetric sales.

The reasoning behind throughput yield reduction is best stated by the Natural Resources Defense Council (NRDC), which explains that "When sales fall, utilities may not recover all their fixed costs, and when sales increase, utilities may collect more than their authorized fixed costs and reasonable return…."[4] The Regulatory Assistance Project further states that removing weather volatility aligns utility revenues to the amount authorized by the Commission, and not on the luck of weather conditions.[5]

Q. Will removing the weather adjustment from Schedule 123 affect PGE's support of conservation efforts or funding for conservation?

A. No. Removing the weather adjustment from Schedule 123 will not affect PGE's support of conservation efforts or funding. Having said that, we note that Schedule 123 was proposed after SB 838 funding started being collected from customers. The mechanism was developed in recognition that much of PGE's fixed costs are recovered through volumetric (kWh) rates and that when sales are reduced, fixed cost recovery is at risk. The prospect of reduced sales could create a disincentive to invest in EE. As noted by the independent evaluator of PGE's

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[3] Traditional rate regulation creates a utility throughput incentive as follows. Prices are based on a test year load forecast. After the test year, actual sales usually differ because predicting exact customer use patterns is complex. The complexity is because of the various impacts on customer use including the economy, weather, demographics, electricity end uses, and variation in customer counts, among other variables. So, following the rate case, the utility will sell more or less electricity than what was assumed. Add to this the need for the utility to recover its fixed costs through volumetric kWh sales. The structure creates a disincentive for the utility to encourage customers to lower their consumption through conservation.

[4] https://www.nrdc.org/resources/gas-and-electric-decoupling.

[5] "Decoupling Design: Customizing Revenue Regulation to Your State's Priorities" by Janine Migden-Ostrander and Rick Sedano.

decoupling mechanism in 2013, EE and conservation funding (and acquisition) increased significantly with the passage of SB 838 in 2007 with the collection starting in 2008. Conservation funding from PGE's customers increased from $44 million in 2008 to $108 million in 2017.

Q. Staff and CUB argue that decoupling shifts risk from shareholders to customers.[6] Do you agree?

A. No. CUB is correct that the Commission, in approving PGE's decoupling mechanism, adjusted PGE's return on equity (ROE) by 10 basis points. However, the Commission has approved settlements in five subsequent rate cases without an explicit adjustment for decoupling. Also, the independent evaluator of PGE's decoupling mechanism found that,

> Based on our own empirical study, a review of other studies, and information provided in credit agency ratings reports, we do not find any evidence that the introduction of Schedule 123 reduced PGE's capital risks by a material amount. We therefore do not find a justification for adjusting PGE's allowed return on equity because of Schedule 123.[7]

The independent evaluator recommends that PGE, "Consider removing the weather normalization of "actual" sales (and therefore revenues) from the [SNA] calculation."[8] The independent evaluator goes on to state, "It would allow for the reduction of weather risk for both PGE and its ratepayers. Some progress would be made in this regard by simply removing the weather adjustment to sales."[9]

Q. What else do Staff and CUB claim in regard to full weather decoupling's effect on customer bills and shifting risks to customers?

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[6] CUB Exhibit 300, pages 6-7.
[7] PGE Exhibit 1306, page 71.
[8] PGE Exhibit 1306, page 73.
[9] Id.

A. CUB claims that weather decoupling increases the volatility of customer bills.[10] Staff states that PGE did not provide support for its statement that, "It is a common misconception that full weather decoupling increases risk or shifts risk to customers."[11] Staff also says that, "Full decoupling does not further Commission goals and shifts risk from the company to customers without any offsetting benefit to customers."[12]

Q. Is weather a driver in the volatility of customer bills?

A. Yes. PGE's energy charges are primarily volumetric. In a hotter than average summer month, the customer uses more electricity. That increased use translates to a higher bill. Likewise, in a cooler than average summer month, the customer uses less electricity. Aside from net variable power costs, weather decoupling passes back to the customer the increases in their bill due to warmer than average summers and collects from customers the decreases in their bill due to cooler than average summers. Again, the independent evaluator of PGE's decoupling mechanism recommended removing the weather adjustment to allow full weather decoupling in the SNA.

Q. Does weather decoupling shift risk from shareholders to customers?

A. No. With weather decoupling, the utility and customer take on or avoid weather risk together. For every weather-related decoupling price increase, there is a similar likelihood for a weather-related decoupling decrease. Weather decoupling provides a refund to customers when they use more electricity due to extreme weather. Staff and CUB appear to ignore that benefit.

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[10] CUB Exhibit 300, page 9.
[11] Staff Exhibit 1100, page 7.
[12] Staff Exhibit 1100, page 4.

Q. If the Commission approves PGE's decoupling proposal to remove the weather adjustment, will PGE work to provide decoupling adjustments sooner?

A. Yes. We would like to offer the bill credits or increases in the same bill cycle that they occur so that if customers are paying a higher bill due to extreme weather, they will also receive a decoupling bill credit. If customer bills are lower due to especially mild weather, then the decoupling surcharge occurs at the time of low bill. Our goal is to provide decoupling adjustments on the monthly bill to which the adjustment is based. This would address one of CUB's concerns that the current system has customers bearing the cost or credit the following year and may not lead to customer bill stability. While PGE's internal systems are not in place to make that happen for 2019, PGE plans to update Schedule 123 to make monthly adjustments in the next few years.

Q. Please discuss the baseline used for decoupling.

A. PGE's prices are set using its revenue requirement and a load forecast; basically, revenues divided by quantity. The baseline used to set the quantity is the load forecast.

Q. You have discussed weather risk in terms of fixed cost recovery and revenue and bill stability. Is PGE also exposed to weather risk through the load forecast?

A. Yes. The load forecast is based on certain weather assumptions that inform customer usage. PGE is exposed to weather risk through the load forecast in a different way than through the weather adjustment to the actual loads for decoupling purposes. PGE currently uses a 15-year average for weather in the load forecast. However, an inherent bias exists due to observed long-term warming in PGE's service area. The practical effect on PGE is under-recovery of revenues due to a higher baseline forecast than what is likely to occur given the warming trend. PGE has proposed trended weather for load forecasts in this general rate case, that is discussed in PGE Exhibits 1100, 2300, and 2800.

Q. Please discuss CUB's arguments that a deferral of weather decoupling, is retroactive ratemaking.

A. CUB raised the issue of retroactive ratemaking in opening testimony.[13] The argument is that because PGE applies the decoupling credit or surcharge the year after it results, it is retroactive ratemaking that does not fall within the deferral statute. In reply testimony, PGE indicated the issue would be addressed in legal briefing, noted that the Commission has approved weather decoupling for gas utilities, and that CUB, while arguing retroactive ratemaking here, was party to a stipulation supporting weather decoupling for a gas utility.[14] CUB acknowledges that it supported weather decoupling for Cascade and Avista in Oregon, and that natural gas and electricity have different weather risks.[15]

Q. How do you respond to CUB's arguments about retroactive ratemaking?

A. We note that CUB's retroactive ratemaking claim is very similar to a 2007 resolution proposed by the National Association of State Utility Advocates (NASUCA) expressing concern about decoupling and other mechanisms and urging Commissions to disallow revenue true-ups in between rate cases. In response, a number of environmental and other advocacy organizations published a response.[16] We think they said it well:

> Traditional ratemaking makes ample provision for "trackers" and/or true-ups associated with, <u>e.g.,</u> fuel costs; decoupling is no different in its "single issue" and

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[13] CUB Exhibit 200, pages 22-23.
[14] PGE Exhibit 2400, page 8.
[15] CUB Exhibit 300, pages 10-11.
[16] The response is entitled, "A Response to the NASUCA 'Decoupling' Resolution" and is dated August 2007. The organizational signatories include: The Alliance to Save Energy, American Council for an Energy Efficient Economy, Conservation Law Foundation, Environment Northeast, Isaak Walton League of America, Natural Resources Defense Council, Northwest Energy Coalition, Orion Energy, Pace Energy Project, Rocky Mountain Institute, Western Resource Advocates.

"retroactive" implications, rate impacts are lower, and the public interest justification is at least as compelling. Ken Costello of the National Regulatory Research Institute has investigated whether decoupling mechanisms meet the traditional tests justifying state utility regulators' use of "tracking mechanisms that adjust rates and revenues whenever sales deviate from their targeted level," and has concluded that "[u]nless a state commission faces legal restrictions in implementing a 'sales tracker' or has a built-in policy of limiting trackers in general, [revenue decoupling] would seem to meet the regulatory threshold for a tracker." Ken Costello, Briefing Paper: Revenue Decoupling for Natural Gas Utilities, p. 9 (National Regulatory Research Institute, April 2006).

Q. Do you have any additional response?

A. Yes. We note that the Washington Utilities and Transportation Commission, in approving Puget Sound Energy's decoupling measure found that there was no retroactive ratemaking.[17] Finally, CUB's arguments are inconsistent. CUB fails to explain why less weather risk for electric utilities than for natural gas utilities provides a reason for CUB and others to support weather decoupling for gas utilities, and object to PGE. CUB's main argument against weather decoupling is that it transfers risk from shareholders to customers. As already discussed, both PGE and the independent evaluator report, don't agree that risk is transferred to customers. But knowing that CUB's view is that weather decoupling transfers risk to customers, the fact that more weather risk exists for natural gas utilities would mean that, in CUB's view, more risk would be transferred to customers, yet CUB supported it. Given CUB's views on the transfer of risk, it makes more sense to support weather decoupling for electric utilities.

The fact remains that there is precedent for weather decoupling in Oregon and both CUB and Staff supported it. We continue to advocate for the Commission to approve PGE's modifications to the Schedule 123 decoupling mechanism to include weather.

[17] Docket No. UE-901183-T, Third Supplemental Order (April 10, 1991), p. 10. The Commission determined that the mechanism did not constitute retroactive ratemaking even though it did not perfectly match costs and rates, stating: "even under the current system of ratemaking, costs and rates will diverge immediately following implementation of a rate change."

Q. Please discuss CUB's arguments around the carry forward provision for the 2% cap on decoupling adjustments.

A. CUB does not think it is necessary and does not address Avista's 3% limit and provision to carry forward balances in excess of 3%.[18] Instead, CUB states that, "As long as decoupling is weather normalized, there is not a need to change the cap. It is the addition of weather that causes a need for greater surcharges."[19]

Q. Do you agree?

A. We agree that the carry forward provision for the 2% cap should apply to approved weather decoupling. The introduction of weather decoupling and removal of the weather adjustment prompted us to address the cap. We note that when the Commission approved the decoupling measure for PGE, it included a cap and the ability to carry forward balances. Upon granting reconsideration of Order No. 09-020 in response to CUB, the Commission, in Order No. 09-176, modified its order to eliminate the carry forward. The cap should have a carry forward provision regardless, but the importance of the carry forward provision becomes more pronounced with weather decoupling.

Q. Staff argues that PGE has not provided new arguments supporting its proposal to carry forward to future years the ability to collect from customers amounts over the 2% cap. Does Staff acknowledge the 3% limit for Avista with the associated carry forward provision?

A. No. This is not surprising in that Staff refuses to acknowledge that decoupling has any benefit for customers. Staff, like CUB, was a party to the decoupling settlement for Avista. However,

[18] PGE Exhibit 2400, page 7.
[19] CUB Exhibit 300, page 11.

Staff does not explain why decoupling, including the carry forward provision, makes sense for some utilities, but not for others.

Q. What concerns does Staff express regarding expanding decoupling to larger nonresidential schedules?

A. Staff claims that large customers may be harmed during periods of low economic activity.

Q. What concerns does CUB express regarding expanding decoupling to larger nonresidential schedules?

A. CUB expresses concern that during recessions, a decoupling charge to large commercial and industrial customers could fall on other commercial and industrial customers.[20]

Q. Did PGE consider the concerns expressed by Staff and CUB about decoupling applying to large customers when it devised its decoupling proposal for this case?

A. Yes. PGE addressed a similar concern from Staff in reply testimony.[21] PGE's proposal does not apply to its largest customers on Schedule 89 and 90. The largest customers that decoupling would apply to under PGE's proposal is Schedule 85, applicable to nonresidential customers with facility capacity from 201 kilowatts (kW) to 4 megawatts (MW). However, if the Commission is concerned that PGE chose a threshold that is too high for the applicability of the SNA, it could limit decoupling so that it does not apply to Schedule 85 customers.

[20] CUB Exhibit 300, pages 11-12.
[21] PGE Exhibit 2400, pages 4-5.

III. Schedule 122 (Renewable Resources Automatic Adjustment Clause)

Q. What is the purpose of this portion of your testimony?

A. In this portion of testimony, we respond to AWEC's and CUB's recommendation regarding the proposed language change to PGE's Schedule 122 Renewable Resources Automatic Adjustment Clause (Schedule 122).

Q. Please summarize PGE's proposal regarding Schedule 122.

A. In PGE Exhibit 1300, PGE proposed to add energy storage to the Schedule, given the direction in Senate Bill (SB) 1547 allowing certain storage costs to be recovered through an automatic adjustment clause. More specifically SB 1547, Section 11 directs:

> (2)(a) The Public Utility Commission shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources [*and for*], costs related to associated electricity transmission and costs related to associated energy storage.

In PGE Exhibit 2400, PGE addressed AWEC's concern that the cost recovery be limited to the statute's requirements and AWEC's proposed inclusion of the statutory language and reference to "associated energy storage."

Q. Did Staff file any testimony regarding Schedule 122?

A. No. Staff did not address the issue. AWEC and CUB are the only Parties who filed testimony on this issue.

Q. Please summarize AWEC and CUB's rebuttal testimony regarding Schedule 122.

A. AWEC sees PGE's proposal on Schedule 122 as untimely as they see no need to modify the Schedule without an energy storage project in construction or acquisition. Similarly, CUB also does not see an immediate need to modify Schedule 122. In addition, AWEC sees this issue as a policy decision to be determined in a rulemaking or investigatory proceeding.

Finally, AWEC sees PGE's proposal to be that any energy storage project would qualify as "associated energy storage."

Q. Is PGE seeking to recover its costs of all energy storage, regardless of the purpose, through the automatic adjustment clause, Schedule 122?

A. No. We recognize that the law allows "associated energy storage" to be recovered through an automatic adjustment clause. In using the undefined term "associated energy storage," the legislature distinguished it from all energy storage. When asserting in our testimony that all PGE's energy storage costs were "associated energy storage costs," we meant to signal, to Parties in this docket, that we believe all of our planned storage projects pursuant to UM 1856 (House Bill 2193), fit within "associated energy storage.". However, we are not, in this rate case, asking Parties to pre-determine whether an investment meets the requirement of "associated energy storage." Rather, we are requesting that the legislatively authorized automatic adjustment clause be established as part of Schedule 122, leaving the determination to the Commission in future cost recovery filings.

Q. If "associated energy storage" is permitted to be included in Schedule 122, what would be the cost recovery process for energy storage investments?

A. If the language "associated energy storage" is included in Schedule 122, as permitted by law, PGE's energy storage costs would either fall into "associated energy storage" or not. If PGE believed they fit within the meaning of "associated energy storage," PGE would seek cost recovery of costs by filing an advice filing proposing to change Schedule 122 prices. In the filing, PGE would provide information about the energy storage project to demonstrate that it is "associated energy storage," eligible for recovery. The filing would then be reviewed by Staff and subject to review and approval by the Commission. If parties had concerns about whether costs fell within the meaning of "associated energy storage," they could participate in the public process to review the proposed Schedule 122 prices.

Q. Both AWEC and CUB argue that there is no immediate need to modify Schedule 122. Does PGE agree?

A No. There is a possibility that eligible energy storage projects would be in service prior to PGE's next general rate case.

Q. In earlier testimony, CUB raised concerns about adding storage to Schedule 122 as that schedule is used for cost recovery associated with costs incurred pursuant to the Renewable Portfolio Standard (RPS). Rather than using Schedule 122, would PGE consider creating a new schedule for recovery of associated energy storage costs?

A. Yes. PGE would consider creating a new automatic adjustment clause schedule for "associated energy storage." That way, costs incurred for associated energy storage would not be confused with costs incurred to meet the RPS and not be confused with costs subject to the cost cap. CUB expresses concern that if associated energy storage costs are recovered through Schedule 122, the associated energy storage costs may be subject to the cost cap found in Oregon Regulatory Statute (ORS) 469A.100 and if substantial enough, could excuse the electric utility from complying with the RPS per ORS 469A.100(1). The cost cap applies to the incremental cost of complying, the cost of unbundled renewable energy certificates and alternative compliance payments. Associated energy storage is not a cost of compliance with the RPS and as such, is not part of the cost cap calculation.

Q. Does this conclude your testimony?

A. Yes.