

**BEFORE THE WASHINGTON  
UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION,**

**Complainant,**

**v.**

**PACIFIC POWER & LIGHT  
COMPANY,**

**Respondent.**

**DOCKETS UE-140762 and UE-140617  
(consolidated)**

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**In the Matter of the Petition of**

**PACIFIC POWER & LIGHT  
COMPANY,**

**For an Order Approving Deferral of  
Costs Related to Colstrip Outage.**

**DOCKET UE-131384 (consolidated)**

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**In the Matter of the Petition of**

**PACIFIC POWER & LIGHT  
COMPANY,**

**For an Order Approving Deferral of  
Costs Related to Declining Hydro  
Generation.**

**DOCKET UE-140094 (consolidated)**

**PACIFIC POWER & LIGHT COMPANY  
REBUTTAL TESTIMONY OF GREGORY N. DUVALL**

**TABLE OF CONTENTS**

PURPOSE AND SUMMARY ..... 1

POLICY OVERVIEW ..... 5

UPDATED RECOMMENDATION FOR NET POWER COSTS ..... 7

COMPANY RESPONSES TO PROPOSED NPC ADJUSTMENTS ..... 12

    Exclusion of California and Oregon QF PPAs ..... 12

    Energy Imbalance Market..... 28

*EIM Background and Status*..... 29

*General Objections to EIM Benefit Imputation* ..... 30

*Objections to Imputing Benefits for EIM Inter-Regional Dispatch* ..... 36

*Objections to Imputing Benefits for EIM Intra-Regional Dispatch* ..... 38

*Objections to Imputing Benefits for EIM Reserve Diversity* ..... 41

*Objections to Imputing Benefits for Within-Hour Dispatch*..... 43

*Other Objections to Imputing EIM Benefits*..... 46

    Inter-Hour Integration..... 47

RENEWABLE RESOURCE TRACKING MECHANISM..... 51

LOW HYDRO DEFERRAL..... 59

THERMAL OUTAGE MODELING ..... 61

ACCEPTED ADJUSTMENT..... 64

**ATTACHED EXHIBITS**

- Exhibit No. GND-5—Rebuttal Pro Forma Net Power Costs
- Exhibit No. GND-6—Rebuttal Update Summary
- Exhibit No. GND-7—PacifiCorp EIM Participating Resources
- Confidential Exhibit No. GND-8C—Low Hydro Deferral

1 **Q. Are you the same Gregory N. Duvall who previously submitted direct testimony**  
2 **in this case on behalf of Pacific Power & Light Company (Pacific Power or**  
3 **Company), a division of PacifiCorp?**

4 A. Yes.

5 **PURPOSE AND SUMMARY**

6 **Q. What is the purpose of your testimony?**

7 A. My testimony presents the Company's rebuttal net power costs (NPC), including  
8 updates to improve the accuracy of the pro forma NPC. I respond to the NPC-related  
9 issues raised by Mr. David C. Gomez on behalf of Washington Utilities and  
10 Transportation Commission (Commission) Staff and Mr. Bradley G. Mullins on  
11 behalf of Boise White Paper, LLC (Boise). I also respond to the testimonies of  
12 Mr. Jeremy B. Twitchell on behalf of Staff, Ms. Donna M. Ramas on behalf of the  
13 Public Counsel Division of the Washington Attorney General's Office (Public  
14 Counsel), and Mr. Mullins recommending that the Commission reject the Company's  
15 proposed renewable resource tracking mechanism (RRTM).

16 **Q. Please summarize your testimony related to the Company's NPC update.**

17 A. Consistent with the Commission's long-standing policy supporting NPC updates in  
18 rate cases, the Company updated its NPC to reflect the most recent data on costs for  
19 the rate-effective period. The Company's updated NPC for the west control area  
20 under the Company's West Control Area inter-jurisdictional allocation methodology  
21 (WCA) are approximately \$592.7 million, or \$135.6 on a Washington-allocated basis.  
22 Updated NPC are approximately \$5.4 million higher than the NPC included in the  
23 initial filing on a Washington-allocated basis.

1           The NPC updates are similar to those included in Pacific Power’s previous  
2 Washington rebuttal filings. The most significant aspect of the NPC update is an  
3 increase in the Company’s coal supply costs at the Jim Bridger plant from the Black  
4 Butte and Bridger mines. I explain why this coal cost update is reasonable as a policy  
5 matter, and I support providing other parties an opportunity to respond to it in  
6 supplemental testimony. Ms. Cindy A. Crane provides details on the updated coal  
7 costs in her testimony.

8 **Q. Please summarize your testimony responding to NPC adjustments proposed by**  
9 **the parties.**

10 A. My testimony demonstrates that:

- 11 • Including power purchase agreements (PPAs) with qualifying facilities (QFs)  
12 located in California and Oregon in the Company’s west control area NPC is fully  
13 consistent with state and federal energy policy supporting renewable energy  
14 development, complies with Public Utility Regulatory Policy Act of 1978  
15 (PURPA) mandates, and is otherwise fair to Washington customers and the  
16 Company. Although it is appropriate to treat the Company’s west control area QF  
17 PPAs like all other west control area PPAs, the Company includes two alternative  
18 approaches: (1) re-pricing the out-of-state QFs at Washington avoided prices to  
19 mitigate the impact of other states’ policy decisions; or (2) adjusting state  
20 allocation factors to reflect the implicit assumption that a situs-assigned resource  
21 serves only the state where it is located. The parties dismissed these alternatives,  
22 but my testimony demonstrates that these alternatives respond to the

1 Commission's concerns in the Company's 2013 rate case and deserve serious  
2 consideration.

- 3 • The anticipated benefits from participating in the energy imbalance market (EIM)  
4 with the California Independent System Operator (CAISO) during the rate-  
5 effective period are not yet known and measurable, particularly because the EIM  
6 is conceptually incompatible with the WCA. Boise proposes to impute EIM  
7 benefits relying on a report issued by Energy and Environmental Economics, Inc.  
8 (E3 Report), which was not developed for ratemaking purposes, does not cover  
9 the pro forma period in this case, and is not specific to the west control area. In  
10 addition, Boise's adjustments include benefits that are already reflected to some  
11 extent in the Company's pro forma NPC and credit NPC for avoided within-hour  
12 costs that are not included in the hourly GRID model to begin with. It is  
13 reasonable to exclude both EIM costs and benefits from rates, consistent with the  
14 Company's initial filing.
- 15 • Inter-hour integration of load and wind resources is appropriately reflected in the  
16 Company's NPC and is not duplicated by modeling load and wind profiles on an  
17 hourly basis.
- 18 • For the purpose of setting rates, the Company uses a single-year median water  
19 year, and therefore extraordinary hydro events are not reflected in NPC and the  
20 Company has no way of recovering costs related to lower-than-median hydro.  
21 The Company forecasts that hydro output in 2014 will be about 300,000  
22 megawatt-hours, or eight percent below the amount included in rates. The

1 Company's filed hydro deferral is the only mechanism available to recover the  
2 cost of lower than expected hydro generation.

- 3 • The Company's approach to the Colstrip and Chehalis forced outages allows the  
4 Company to recover its prudent power supply costs. Denying the deferral for  
5 Colstrip or removing the Chehalis outage from the four-year forced outage rate  
6 effectively denies the Company recovery for its prudent costs.
- 7 • With certain corrections, Boise's adjustment to reduce wheeling expenses related  
8 to network integration transmission service (NITS) provided by the Bonneville  
9 Power Administration (BPA) is reasonable. The Company has corrected the  
10 calculation for the pro forma period, resulting in a reduction to west control area  
11 NPC of \$0.8 million.

12 **Q. Please summarize your rebuttal testimony related to the Company's proposal**  
13 **for the RRTM.**

14 A. The RRTM addresses the Company's growing fleet of renewable resources, which  
15 enable the Company to comply with Washington laws and policies requiring the  
16 development of renewable generation. The RRTM is designed to protect both the  
17 Company and customers by ensuring that customers pay no more or less than the  
18 actual costs to serve them with renewable resources. While the Company appreciates  
19 Staff's proposal for a power cost adjustment mechanism (PCAM) in lieu of the  
20 RRTM, Staff's PCAM does not address the under-recovery of renewable resource  
21 costs or negate the need for the RRTM. In response to the parties' concerns, the  
22 Company modified its proposed RRTM to prevent the possibility of NPC over-  
23 recovery by capping the potential adjustment under the RRTM at the Company's

1 actual NPC. As a practical matter, the risk that this cap would ever be triggered is  
2 low. Since 2007, the Company has under-recovered its NPC in Washington in every  
3 year, by an average of nine percent.<sup>1</sup>

#### 4 **POLICY OVERVIEW**

5 **Q. Please address the policy issues implicated by your rebuttal testimony.**

6 A. As described in more detail in the rebuttal testimony of Mr. R. Bryce Dalley, the  
7 Company is in a period of significant transformation as it responds to laws and  
8 regulations that have increased the development of renewable and distributed  
9 generation in the Pacific Northwest. Washington has been at the forefront of this  
10 transformation, adopting a regional approach to advance state environmental and  
11 energy policies:

- 12 • In 2006, voters enacted the Energy Independence Act (EIA), creating  
13 Washington’s renewable portfolio standard (RPS) to encourage the regional  
14 development of renewable resources;<sup>2</sup>
- 15 • In 2007, the legislature enacted Washington’s Greenhouse Gas Emissions  
16 Performance Standard (EPS) to increase the use of renewable resources to serve  
17 Washington customers;<sup>3</sup>
- 18 • In 2008, Washington enacted the Climate Action and Green Jobs bill to further  
19 promote renewable energy development;<sup>4</sup>

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<sup>1</sup> Pacific Power’s Response to Staff data request 89.

<sup>2</sup> RCW 19.285.020 (EIA provides that Washington should increase the use of “renewable energy facilities”). Laws of 2013, ch. 61 (amending the definition of “eligible renewable resource” in RCW 19.285.030, effective July 28, 2013). Now, RCW 19.285.030(12)(a) and (e) define “eligible renewable resource” to include facilities located in the Pacific Northwest as well as facilities in other states where the qualifying utility has a renewable resource and serves retail customers.

<sup>3</sup> RCW 80.80.005(1)(d).

<sup>4</sup> RCW 70.235.005(1).

- 1           • In 2010, the legislature directed Washington’s State Energy Office to prepare a  
2           state energy strategy to “promote energy self-sufficiency through the use of  
3           indigenous and renewable energy sources, consistent with the promotion of  
4           reliable energy sources[;]”<sup>5</sup>
- 5           • In 2013, Washington passed a second Climate Action Bill to further reduce  
6           greenhouse gas (GHG) emissions;<sup>6</sup>
- 7           • In October 2013, Washington signed the Pacific Coast Action Plan on Climate  
8           and Energy to provide coordination among the states and provinces of the west  
9           coast to “link programs for consistency and predictability and to expand  
10          opportunities to grow the regions low-carbon economy;”<sup>7</sup>
- 11          • In April 2014, Governor Jay Inslee issued an Executive Order specifically  
12          recognizing the Washington had joined Oregon and California, “calling for  
13          additional West Coast actions on climate leadership, clean transportation, and  
14          clean energy and infrastructure.”<sup>8</sup>

15   **Q.    Please explain how these policy issues inform the issues covered in your rebuttal**  
16   **testimony.**

17   A.    As described in Mr. Dalley’s testimony, in this case, the Company made several  
18   proposals intended to better position the Company to respond to the challenges  
19   resulting from changing Washington state laws and policies. With respect to NPC,  
20   the Company proposed the RRTM to mitigate the risks caused by the variability in  
21   the Company’s growing portfolio of renewable resources. The RRTM will ensure

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<sup>5</sup> RCW 43.21F.010(3).

<sup>6</sup> Laws of 2013, ch. 6.

<sup>7</sup> Pacific Coast Action Plan on Climate and Energy at 1 (Oct. 28, 2013). A copy of this plan is included as Exhibit No. RBD-4 to Mr. Dalley’s rebuttal testimony.

<sup>8</sup> Executive Order 14-04 at 2 (Apr. 29, 2014).



1 that both the Company and customers are protected from the volatility inherent in  
2 renewable generation.

3 The Company also renewed its request for a change to the WCA to allow cost  
4 recovery of all PPAs with QFs in the west control area, all of which are renewable  
5 resources.

6 **Q. The parties argue that the RRTM and the modification to the WCA related to  
7 QF generation are contrary to Commission precedent. Why is the Company  
8 asking the Commission to take a new direction in this case?**

9 A. To respond to the rapidly changing energy landscape in Washington, the Company  
10 urges the Commission to reconsider as necessary its prior decisions that predate or  
11 otherwise do not take into account the Washington laws now driving electric industry  
12 transformation. The recent legislative changes outlined above provide a strong basis  
13 for a different outcome in this case.

14 **UPDATED RECOMMENDATION FOR NET POWER COSTS**

15 **Q. Have you updated the Company's recommended pro forma NPC?**

16 A. Yes. The Commission's policy is that "power costs determined in general rate  
17 proceedings and in [power cost only] proceedings should be set as closely as possible  
18 to costs that are reasonably expected to be actually incurred during short and  
19 intermediate periods following the conclusion of such proceedings."<sup>9</sup> Consistent with  
20 this policy, the Company updated its pro forma NPC to reflect the most current  
21 information available, including a new forward price curve; updates to several PPAs  
22 (including QF PPAs); fuel costs, including coal and natural gas supply; and updates to

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<sup>9</sup> *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket No. UE-060266, Order 08 ¶ 102 (Jan. 5, 2007).

1 gas transportation costs. The Company's updated NPC recommendation is required  
2 to produce the most accurate projection of west control area NPC for the pro forma  
3 period in this case (the 12 months ending March 31, 2016).

4 **Q. What is the Company's updated NPC recommendation?**

5 A. The Company increased its recommended west control area NPC from \$568.8 million  
6 to approximately \$592.7 million, an increase of \$23.9 million. On a Washington-  
7 allocated basis, NPC increases by approximately \$5.4 million to \$135.6 million. The  
8 NPC report for the Company's rebuttal filing is presented in Exhibit No. GND-5.

9 **Q. Have you provided an exhibit that summarizes the change in NPC from your  
10 direct testimony on a west control area basis?**

11 A. Yes. Exhibit No. GND-6 summarizes the impact of all individual updates on west  
12 control area NPC.

13 **Q. Please provide more detail on the updates included in rebuttal NPC?**

14 A. The Company's rebuttal NPC study now reflects:<sup>10</sup>

- 15 • Updated tariff rates for the Chehalis natural gas lateral pipeline;
- 16 • Updated costs for the PGE Cove purchase contract;
- 17 • Updated coal expense reflecting changes in fuel supply costs and volume for the  
18 pro forma period;
- 19 • Updated Mid-Columbia (Mid-C) hydro contract costs;
- 20 • Changes to three small Oregon QF PPAs, including one removal, one update, and  
21 one addition;
- 22 • The Company's September 30, 2014 official forward price curve;

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<sup>10</sup> The Company's rebuttal NPC also includes one minor correction to the price assumed for the Douglas County Forest Products QF PPA. The impact of the correction is a reduction to west control area NPC of \$2,729.

- 1           • Updated short-term firm transactions executed through October 1, 2014; and
- 2           • Reduced wheeling expenses related to the Goodnoe Hills large generator
- 3           interconnection agreement.

4   **Q.   Please identify the main drivers of the increase in the NPC update.**

5   A.   Compared to the Company’s initial filing, the increase in NPC is predominantly due

6       to updated coal supply costs for the Jim Bridger plant. In summary, the Company

7       recently concluded negotiations with Black Butte mine for coal supply in the rate

8       period, reflecting a price increase. At the same time, the Company now projects

9       lower production from the Bridger mine in the rate period and the need to purchase

10       additional coal from the Black Butte mine. Ms. Crane provides additional detail

11       supporting the Company’s updated coal costs.

12   **Q.   Do you believe that the NPC updates you are sponsoring satisfy the**

13       **Commission’s standards?**

14   A.   Yes. The updated information used in the NPC study that underlies my rebuttal

15       testimony is indicative of the actual costs the Company will incur during the rate-

16       effective period.

17   **Q.   Will the proposed coal supply cost updates for the Jim Bridger plant further the**

18       **Commission’s interest in setting NPC as closely as possible to costs reasonably**

19       **expected to be incurred in the rate-effective period?**

20   A.   Yes. The updated coal cost information is the best available evidence for the

21       expected level of coal supply costs for the Jim Bridger plant in the rate-effective

22       period. Without the update, the estimated level of coal costs included in rates will be

23       inaccurate and will not match other costs and revenues reflected in NPC.

1 **Q. Did the Company significantly under-recover its NPC in 2013?**

2 A. Yes. On a west control area basis, the Company under recovered its NPC by  
3 \$33.2 million.<sup>11</sup> The Company's NPC update is necessary to guard against a similar  
4 outcome in the rate-effective period.

5 **Q. Is the Company's updating of coal costs consistent with past proceedings?**

6 A. Yes, the Company updated its coal costs as part of the NPC updates in its last two  
7 litigated cases, the 2010 and 2013 general rate cases. In the 2010 case, Docket  
8 UE-100749, the Company updated its third-party coal contracts and fuel volumes,  
9 which resulted in an increase in west control area NPC of approximately \$1.1 million.  
10 Similarly, in the 2013 case, Docket UE-130043, the Company updated coal costs to  
11 reflect changes in contract costs and fuel volume, which resulted in a decrease in west  
12 control area NPC of approximately \$2 million. No party objected to these updates,  
13 and the Commission approved them in its final orders.

14 **Q. Did either of the coal cost updates in the 2010 or 2013 rate cases involve an  
15 update to Bridger coal costs?**

16 A. In both cases the Bridger coal volumes were updated to reflect changes in the forward  
17 curve, although the price per ton was not updated. In this case, updating Bridger coal  
18 pricing is reasonable because the updated price correlates to the cost increase for the  
19 Black Butte mine, updates to which the Commission has approved in the Company's  
20 most recent cases, and is a result of changing production volumes at the Bridger mine.  
21 As described in the testimony of Ms. Crane, the updated cost per ton of coal from  
22 both the Bridger and the Black Butte mines are similar, establishing the  
23 reasonableness of the updated Bridger coal costs.

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<sup>11</sup> Testimony of David C. Gomez, Exhibit No. DCG-5CT.

1 **Q. Did the Company propose an update to Bridger coal costs in its 2011 rate case,**  
2 **Docket UE-111190?**

3 A. Yes. While the parties objected to the update, unlike this case, the 2011 rate case did  
4 not include a parallel increase in third-party coal costs from the Black Butte mine that  
5 corroborated the reasonableness of the cost increases at the Bridger mine. In that  
6 case, the NPC witness for the Industrial Customers of Northwest Utilities (ICNU)  
7 proposed that the price of coal from the Black Butte mine be used to re-price Bridger  
8 coal in the update.<sup>12</sup> The parties ultimately settled the case without resolving this  
9 issue.

10 **Q. Did Boise participate in Docket UE-111190 as a member of ICNU?**

11 A. Yes. Recent filings in these consolidated cases make clear that Boise has participated  
12 in Pacific Power's Washington rate cases for many years as a member of ICNU and  
13 continues to do so. In Boise's Petition to Intervene in Docket UE-131384, the  
14 Company's accounting petition related to the Colstrip plant now consolidated with  
15 this case, Boise acknowledged that it had participated in nine of Pacific Power's  
16 Washington rate cases as a member of ICNU, specifically including Docket  
17 UE-111190.<sup>13</sup> Similarly, in April 2014, when ICNU petitioned to intervene in Docket  
18 UE-140617, also consolidated with this case, it noted that it was doing so on behalf of

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<sup>12</sup> *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-111190, Responsive Testimony of Donald W. Schoenbeck, Exhibit No. DWS-1CT at 3 ("The majority of coal supplied to the Jim Bridger plant comes from an affiliated mine. Adequate time has not been provided to assess the reasonableness of the Company's coal price updates. As a placeholder, ICNU recommends the updated price from the third party supplier be used as a price cap on the allowable Jim Bridger coal costs. This recommendation reduces the claimed revenue increase by \$1.6 million.")

<sup>13</sup> *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-131384, Petition to Intervene of Boise White Paper, L.L.C. at 2 (Jan. 13, 2014) ("Boise directly participated in PacifiCorp's most recent general rate case and has participated, as a member of the Industrial Customers of Northwest Utilities, in other PacifiCorp rate proceedings, including UE-991832, UE-032065, UE-050684, UE-060669, UE-061546, UE-080220, UE-090205, UE-100749, and UE 111190.")

1 its members, “including the Packaging Corporation of America, f/k/a Boise White  
2 Paper, L.L.C. (PCA), PacifiCorp’s largest customer in Washington[,]”<sup>14</sup> and further  
3 stated that “ICNU indirectly participated in PacifiCorp’s most recent general rate case  
4 (UE-130043) as PCA[.]”<sup>15</sup>

5 **Q. Given that this update is occurring in your rebuttal testimony, does the**  
6 **Company object to allowing the parties an opportunity to provide responsive**  
7 **testimony on this issue?**

8 A. No. The Company does not object to parties addressing the Company’s NPC update  
9 in supplemental pre-filed testimony or in testimony at the hearing, provided the  
10 Company has a chance to respond to this testimony.

11 **COMPANY RESPONSES TO PROPOSED NPC ADJUSTMENTS**

12 **Exclusion of California and Oregon QF PPAs**

13 **Q. Does any party support the Company’s proposal to include the costs associated**  
14 **with Oregon and California QF PPAs in west control area NPC?**

15 A. No. Staff, Boise, and Public Counsel each reject including California and Oregon and  
16 QF PPAs in west control area NPC.<sup>16</sup> Similar to arguments made in the Company’s  
17 2013 general rate case, Staff and Boise assert that allocating west control area QF  
18 PPAs to Washington inappropriately requires Washington customers to pay for QF-  
19 related policy choices made by California and Oregon. Public Counsel does not  
20 address the appropriate allocation of California and Oregon QF PPAs, but indicates

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<sup>14</sup> See *Wash. Utils. & Transp. Comm’n v. PacifiCorp*, Docket No. UE-140617, Petition to Intervene and Opposition of the Industrial Customers of Northwest Utilities, ¶ 3 (Apr. 25, 2014).

<sup>15</sup> *Id.*, ¶ 4.

<sup>16</sup> See Testimony of David C. Gomez, Exhibit No. DCG-1CT at 9-10; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 23.

1 that Public Counsel supports the Commission’s findings in Docket UE-130043 (2013  
2 Rate Case) and removes the cost of these QFs from west control area NPC.

3 **Q. Is the Company’s proposal in this case exactly the same as in the Company’s**  
4 **2013 Rate Case?**

5 A. No. While the Company’s main proposal in this case is similar to the 2013 Rate Case  
6 in that the costs associated with California and Oregon QF PPAs are included in west  
7 control area NPC, the Company also provided two alternative approaches that would  
8 reasonably reflect the impact of California and Oregon QF PPAs on NPC. First, the  
9 Company proposed re-pricing the out-of-state QFs at Washington avoided cost prices,  
10 so that the costs associated with the QFs reflected Washington state policy choices.  
11 This proposal would decrease Washington revenue requirement by \$2.2 million.  
12 Second, the Company proposed a load decrement approach to QF pricing that would  
13 remove the costs of the out-of-state QF PPAs and also offset each west control area  
14 states’ load with the QFs in that state for purposes of allocating costs and benefits  
15 under the WCA. This proposal would decrease Washington revenue requirement by  
16 \$3.9 million. The rebuttal testimony of Ms. Natasha C. Siores provides the detailed  
17 revenue requirement impact of each proposal. I reproduced her summary table here  
18 for ease of reference.<sup>17</sup>

**TABLE 1**

***Revenue Requirement Summary***

	Revenue Requirement	Change from Filed	
Rebuttal Position	31,938,957		Ref NCS-11, Page 1.1
Re-Pricing at WA QFs Avoided Costs	29,763,224	(2,175,733)	Ref NCS-12, Page 2
Load Decrement	28,009,625	(3,929,332)	Ref NCS-12, Page 3
Situs-Assigned - Excl. OR/CA QFs	22,181,879	(9,757,079)	Ref NCS-12, Page 4

<sup>17</sup> Rebuttal Testimony of Natasha Siores, Exhibit No. NCS-12.

1 **Q. Did the parties address the Company's alternative proposals?**

2 A. Yes. Both Staff and Boise dismissed the Company's alternative proposals as  
3 inconsistent with the Commission's decision in the 2013 Rate Case.

4 **Q. What is the parties' primary argument against Pacific Power's proposals?**

5 A. Based on the Commission's order in the 2013 Rate Case, Staff and Boise argue that  
6 excluding the California and Oregon QF PPAs from the west control area NPC is  
7 equivalent to replacing these resources with market purchases in GRID.<sup>18</sup> Staff and  
8 Boise claim that re-pricing the QF PPAs at market prices protects Washington  
9 customers from policy decisions made by other states and is consistent with the cost  
10 causation principles underlying the WCA.

11 **Q. Is re-pricing the out-of-state QF PPAs at current market prices consistent with  
12 PURPA?**

13 A. No. It is my understanding that re-pricing the out-of-state QF PPAs at current spot  
14 market prices is inconsistent with PURPA's requirement, as interpreted by the  
15 Commission in the Company's Schedule 37, that utilities purchase all energy and  
16 capacity made available by QFs at the utility's avoided cost.

17 **Q. Why is re-pricing the out-of-state QF PPAs at current market rates inconsistent  
18 with PURPA's avoided cost requirements?**

19 A. There are two primary reasons. First, simply relying on market prices does not reflect  
20 Pacific Power's actual avoided costs as determined by the Commission because it  
21 fails to account for the impact of a QF on the Company's existing resources or the

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<sup>18</sup> See, e.g., Testimony of David C. Gomez, Exhibit No. DCG-1CT at 11; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 25-26.



1 QF's ability to defer future capacity additions. PURPA requires the Company to  
2 purchase energy and capacity made available by QFs.

3 Second, the *current* market price does not accurately reflect Pacific Power's  
4 avoided cost of energy included in long-term QF PPAs that were executed years ago  
5 with avoided cost prices determined at the time of execution. PURPA allows QFs to  
6 enter into long-term PPAs with utilities and, at the option of the QF, the avoided cost  
7 prices in those PPAs can be determined at the time the PPA is executed, not at the  
8 time that the energy is delivered to the utility.

9 The Commission's decision to price out-of-state QF PPAs at the current  
10 market price ignores the Company's obligation under PURPA to pay a fixed avoided  
11 cost price over the life of the QF PPA. Thus, even if market prices accurately  
12 reflected Pacific Power's avoided cost of energy, the relevant market prices were  
13 those that were forecast at the time the QF PPAs were executed, not current spot  
14 market prices.

15 **Q. Has the Commission recognized that avoided cost prices must account for both**  
16 **energy and capacity?**

17 A. Yes. Pacific Power's current Schedule 37 requires the Company to pay QFs in  
18 Washington for both energy and capacity, with energy payments reflecting the  
19 Company's incremental cost of market transactions and thermal output, and capacity  
20 payments reflecting the fixed costs associated with a simple cycle combustion turbine  
21 for three months per year. The inclusion of capacity payments in Washington's  
22 avoided cost calculation demonstrates that, in the current view of the Commission,  
23 market prices alone are not equivalent to avoided cost prices.

1 **Q. Has Staff recognized that wind resources provide capacity value to Washington**  
2 **customers?**

3 A. Yes. Staff's cost of service testimony expressly recognizes that wind resources  
4 provide capacity to meet the Company's peak load.<sup>19</sup> As described in the cost of  
5 service testimony of Ms. Joelle R. Steward, the Company's west control area wind  
6 resources, including the out-of-state QFs, contribute 25.4 percent of their nameplate  
7 capacity to meet total system peak load.

8 **Q. Why is it necessary for the avoided cost prices to account for both energy and**  
9 **capacity?**

10 A. It is my understanding that PURPA mandates the use of avoided cost prices to ensure  
11 customer indifference to the QF transaction. In other words, customers should be no  
12 better or worse off because Pacific Power is purchasing its energy and capacity from  
13 a QF rather than from another source. However, if Washington customers are paying  
14 for only the energy from out-of-state QFs, Washington customers are benefiting from  
15 the capacity value provided by the QFs without paying for it. Therefore, re-pricing  
16 the out-of-state QF PPAs at market prices does not result in customer indifference.

17 **Q. Has the Commission previously recognized the importance of ensuring customer**  
18 **indifference?**

19 A. Yes. The Commission has observed that "[b]y its own terms, PURPA was meant to  
20 protect the ratepayers. Avoided cost prices should be established to be no greater  
21 than that which the ratepayers would be expected to pay without PURPA."<sup>20</sup>

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<sup>19</sup> Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 15-16.

<sup>20</sup> *Spokane Energy, Inc. v. Wash. Water Power Co.*, Cause No. U-86-114, 1987 WL 1498338 (Apr. 22, 1987).

1 **Q. How do current market prices compare with the market prices at the time the**  
2 **QFs were executed?**

3 A. The majority of the out-of-state QFs were executed within the last six years. During  
4 that time, market prices have decreased by more than half. Thus, even if the  
5 Commission's re-pricing method was reasonable for purposes of determining the  
6 avoided cost of energy, the contracts must be re-priced at the higher market prices  
7 that were anticipated at the time each PPA was executed. The Company's re-pricing  
8 proposal effectively captures the relevant forward prices and demonstrates the  
9 declining market prices.

10 **Q. Staff claims that the Company provided only vague assertions regarding the**  
11 **benefits provided by the out-of-state QFs to Washington customers.<sup>21</sup> Boise**  
12 **claims that the Company did not identify any direct benefit provided by these**  
13 **QFs that would support full cost recovery.<sup>22</sup> What benefits are provided by the**  
14 **out-of-state QFs?**

15 A. In addition to providing the capacity benefits discussed above, the out-of-state QFs  
16 provide significant benefits because they are renewable, emission-free generators.  
17 Washington state policymakers have been clear that renewable generation provides  
18 significant environmental, cultural, economic, and health benefits to Washington  
19 residents. Thus, the state has taken extensive measures to mandate and promote the  
20 development of exactly the types of resources that Staff and Boise claim provide no  
21 benefit to Washington.

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<sup>21</sup> Testimony of David C. Gomez, Exhibit No. DCG-1CT at 9.

<sup>22</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 26.

1 Emission-free resources may act as a hedge against future carbon regulation,  
2 the exact nature of which is currently unknown. In fact, the Commission has  
3 acknowledged that future carbon regulation may have a significant impact on the  
4 Company's operations.<sup>23</sup> The out-of-state QFs, like all of the Company's renewable  
5 resources, will help to mitigate that impact.

6 **Q. What other benefits are provided by the out-of-state QFs?**

7 A. The QFs provide diversity to the Company's resource portfolio, which can act to  
8 reduce risk. Indeed, *in this case* Mr. Mullins testified on behalf of Boise about the  
9 many benefits provided by wind resources, including the out-of-state QFs:

10 Portfolio diversification is one of the fundamental principles  
11 relied on by utilities in order to develop a least-cost, least-risk  
12 portfolio . . . . For purposes of utility planning, this means that  
13 a utility will benefit from procuring power supplies that are  
14 dependent on many different fuel and resource types.<sup>24</sup>

15 Thus, Mr. Mullins concluded that the Company's "overall system is benefiting as a  
16 result of the diverse nature of all the resources in its portfolio."<sup>25</sup>

17 **Q. Do the QFs allow the Company to avoid other costs?**

18 A. Yes. Without the energy and capacity provided by the QFs, Pacific Power may have  
19 had to procure additional resources. These additional resources may or may not have  
20 been renewable, yet under the WCA these resources would have been included in  
21 Washington rates.

22 **Q. Are there any other benefits provided by QFs?**

23 A. Yes. In a docket before the Public Utility Commission of Oregon (OPUC), Boise's

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<sup>23</sup> See, e.g., *PacifiCorp's 2013 Electric Integrated Resource Plan*, Docket No. UE-120416, Commission Acknowledgement Letter (Nov. 25, 2013).

<sup>24</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 57.

<sup>25</sup> *Id.* at 58.

1 energy trade association ICNU submitted testimony from its expert Mr. Donald W.  
2 Schoenbeck. ICNU’s testimony identified 11 different benefits provided by QFs,  
3 including the following:

4 The second benefit is reliability. A system of 50 smaller  
5 generators of 200 MW each is significantly more reliable than  
6 a similar size system of 20 larger generators of 500 MW each.  
7 The smaller unit system is 100 times less likely to lose 1,000  
8 MW of capacity simultaneously.

9 \* \* \*

10 The fourth benefit is system diversity. Because they distribute  
11 electrical generation among smaller, more efficient generating  
12 facilities, policies that promote cogeneration increase the  
13 reliability of an energy portfolio in the same way a diversified  
14 investment strategy protects investors.

15 \* \* \*

16 The fifth benefit is transmission reliability. Cogeneration  
17 provides a major source of distributed generation for the  
18 electric grid which is a significant operating benefit. By  
19 providing multiple power sources throughout the state, the  
20 demand on the state’s electrical grid and the risks of losing  
21 power when centralized generating facilities fail is reduced.

22 \* \* \*

23 The eighth benefit is reduced transmission losses.  
24 Cogeneration conserves electricity by producing power near  
25 the places it is consumed. This reduces transmission losses and  
26 saves an additional amount of fuel from being burned.<sup>26</sup>

27 **Q. Boise also claims that whether or not the out-of-state QF prices are excessive is**  
28 **irrelevant to cost allocation under the WCA.<sup>27</sup> How do you respond?**

29 A. PURPA makes the QF prices extremely relevant. PURPA requires the Company to  
30 contract with the out-of-state QFs at prices equal to Pacific Power’s avoided cost.

31 The fact that not a single party in this case has argued that the QF PPA prices exceed

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<sup>26</sup> *Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, OPUC Docket No. UM 1129, Direct Testimony of Donald W. Schoenbeck on Behalf of the Industrial Customers of Northwest Utilities at 6-7 (Aug. 3, 2004).

<sup>27</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 26.

1 Pacific Power’s avoided cost prices is significant because, without such a finding, it is  
2 unreasonable to exclude the QF PPAs from rates.

3 **Q. Staff and Boise also argue that the out-of-state QF PPA prices are driven by**  
4 **policies and decisions made by other states to encourage QF development that**  
5 **should not impact Washington rates.<sup>28</sup> Boise further claims that states have**  
6 **significant leeway in implementing PURPA to “set avoided cost rates at higher**  
7 **or lower levels to reflect state renewable energy policies.”<sup>29</sup> How do you respond**  
8 **to these claims?**

9 A. I disagree with Staff and Boise for several reasons. First, I disagree with the  
10 implication that California and Oregon have inflated the avoided cost prices in the QF  
11 PPAs as a reflection of those states’ renewable energy policies. It is my  
12 understanding that states cannot set an avoided cost price that includes a “bonus” or  
13 “adder” intended to encourage renewable development. FERC has stated:

14 [T]he State can pursue its policy choices concerning particular  
15 generation technologies consistent with the requirements of  
16 PURPA and our regulations, **so long as such action does not**  
17 **result in rates above avoided cost.**<sup>30</sup>

18 Moreover, no party to this case demonstrated or even alleged that the avoided cost  
19 prices included in the out-of-state QF PPAs are greater than the Company’s actual  
20 avoided costs as of the time the PPAs were executed. Thus, there is no basis to  
21 conclude that California and Oregon are manipulating the avoided cost prices to  
22 promote state-specific energy or environmental policies.

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<sup>28</sup> Testimony of David C. Gomez, Exhibit No. DCG-1CT at 9-10; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 24.

<sup>29</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 27.

<sup>30</sup> *Re So. Calif. Edison Co.*, 70 F.E.R.C. ¶ 61,215 at 61,676 (1995) (emphasis added).

1           Second, it is my understanding that PURPA is specifically intended to  
2 encourage QF development. Therefore, Staff’s and Boise’s argument has merit only  
3 if one assumes that Washington has decided to not encourage QF development, a  
4 decision that would be contrary to the fundamental purpose of PURPA and contrary  
5 to the Commission’s prior statements.

6           Third, as I discussed previously in my testimony, the states’ energy policies  
7 are strikingly similar and Washington has taken a decidedly regional approach to  
8 encouraging renewable energy development. Both Oregon and Washington, for  
9 example, have used PURPA development to promote distributed generation.  
10 Therefore, the policy differences perceived by Staff and Boise are not as extensive as  
11 they claim.

12           Fourth, if the Commission remains concerned that the avoided cost prices of  
13 the California and Oregon in the QF PPAs reflect those states’ policy decisions, then  
14 the Commission should approve the Company’s alternative recommendation to re-  
15 price the QF PPAs at avoided cost prices determined according to Washington state  
16 policy. As described in more detail below, this re-pricing proposal effectively  
17 removes any perceived differences in PURPA implementation and results in  
18 Washington rates that indisputably reflect Washington state policy decisions.

19 **Q. Staff and Boise claim that the Company’s proposal is based on the “physical**  
20 **flow of power” and not cost causation.<sup>31</sup> How do you respond?**

21 A. I disagree with this characterization. In my testimony, I stress the fact that the out-of-  
22 state QFs provide energy and capacity to serve Washington customers because that

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<sup>31</sup> Testimony of David C. Gomez, Exhibit No. DCG-1CT at 10; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 25.

1 fact—which is undisputed—demonstrates that Washington customers are benefiting  
2 from the QFs. As I discuss above, if Washington customers are receiving energy and  
3 capacity from these QFs, along with all of the other benefits discussed, then it is  
4 reasonable for Washington customers to pay the full costs of the QF PPAs.  
5 Otherwise, Washington customers are receiving the benefits without paying the  
6 associated costs. Thus, the Company’s proposal is consistent with principles of cost-  
7 causation.

8 **Q. Staff also discounts the fact that the Commission has allowed Avista**  
9 **Corporation d/b/a Avista Utilities (Avista) to recover the full costs of out-of-state**  
10 **QF PPAs in Washington rates, claiming that the Commission has not always**  
11 **relied on cost causation when allocating costs across multiple states.<sup>32</sup> Staff**  
12 **claims that the Company’s out-of-state QF costs are higher than Avista’s and**  
13 **therefore must be situs assigned. Do you agree?**

14 A. No. There is no principled basis to allow one Washington utility to recover out-of-  
15 state QF costs while denying Pacific Power recovery of the same types of costs.  
16 PURPA contains no materiality threshold governing cost recovery. Consistency in  
17 regulation requires consistent treatment for all utilities. Simply pointing out that  
18 Avista has had fewer out-of-state QFs does not support differing treatment.

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<sup>32</sup> Testimony of David C. Gomez, Exhibit No. DCG-1CT at 13.



1 **Q. Staff also claims that the Commission can disregard cost causation based on the**  
2 **degree to which state-specific policies may be driving the avoided cost prices. To**  
3 **support this claim, Staff relies on a 1983 Washington Water Power Company**  
4 **order regarding the allocation of costs for an Idaho QF PPA.<sup>33</sup> Does that order**  
5 **support Staff’s position in this case?**

6 A. No. Contrary to Staff’s claim that the Commission situs assigned the Idaho QF PPA  
7 costs to Idaho, a careful reading of the Commission’s order shows that the  
8 Commission did not situs assign the QF costs at all. Rather, the Commission  
9 determined that the avoided costs in the QF PPA were excessive and disallowed cost  
10 recovery of the amounts that exceeded Washington Water Power’s avoided costs. In  
11 other words, the Commission applied the Company’s alternative proposal and re-  
12 priced the QF PPA at Washington avoided cost prices.

13 **Q. What is the basis for your conclusion that the Commission re-priced the QF PPA**  
14 **at Washington’s avoided cost prices?**

15 A. The issue presented in the case was whether Washington Water Power’s proposed  
16 rate revision, which would have included the full Washington-allocated costs of the  
17 QF PPA, was just and reasonable. The Commission observed that, “[i]n reaching this  
18 ultimate determination, the commission must make the underlying determination  
19 whether the proposed purchase agreement is based on a proper methodology to  
20 calculate the avoided cost as defined by federal and state laws and rules.”<sup>34</sup> Thus, the

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<sup>33</sup> Testimony of David C. Gomez, Exhibit No. DCG-1CT at 10 (citing *Wash. Utils. & Transp. Comm’n v. Wash. Water Power Co.*, Cause No. U-83-14, Second Suppl. Order, 56 P.U.R.4th 615 (Nov. 9, 1983)).

<sup>34</sup> *Wash. Utils. & Transp. Comm’n v. Wash. Water Power Co.*, Cause No. U-83-14, Second Suppl. Order, 56 P.U.R.4th 615, 1983 WL 909042 at 2 (Nov. 9, 1983).

1 Commission analyzed whether the avoided cost prices in the QF PPA were consistent  
2 with PURPA. The Commission did not simply situs assign the costs to Idaho.

3 In the Washington Water Power case, Staff concluded that the rates in the QF  
4 PPA were higher than Washington Water Power's avoided cost and therefore  
5 inappropriate. The Commission agreed, concluding that the "amount to be paid under  
6 the purchase agreement is in excess of properly determined avoided costs."<sup>35</sup> Thus,  
7 the Commission disallowed cost recovery of the amounts that exceeded the avoided  
8 cost price as determined by the Commission. Applying the same standard to this case  
9 would require approval of the Company's Washington re-pricing proposal.

10 **Q. Staff testifies that in the Washington Water Power case, the QF PPA "pricing  
11 and terms were driven by Idaho state policies at the time."<sup>36</sup> Do you agree with  
12 this characterization of the order?**

13 A. No. Nowhere in the order does it suggest that the avoided cost price in the QF PPA  
14 was the result of Idaho state policies. In addition, Staff testifies in this case that once  
15 the Commission chose to situs assign the costs to Idaho, the Idaho commission  
16 accepted that decision. Again, however, the Commission did not situs assign the  
17 costs to Idaho, and the order says nothing about how the Idaho commission responded  
18 to the Commission's order.

19 **Q. Staff and Boise reject the Company's alternative proposal to re-price the out-of-  
20 state QF PPAs as if they were Washington QF PPAs. What is the basis for their  
21 rejection of this proposal?**

22 A. The parties argue that this proposal is inconsistent with cost causation and merely

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<sup>35</sup> *Id.* at 8.

<sup>36</sup> Testimony of David C. Gomez, Exhibit No. DCG-1CT at 13 n. 24.

1 discounts the cost impact of state policy decisions made by California and Oregon.<sup>37</sup>

2 Boise also claims that the Washington re-pricing proposal still burdens Washington  
3 customers with other states' energy policies because there is no way to know if the  
4 out-of-state QFs would have been developed if they had been subject to Washington's  
5 PURPA policies.<sup>38</sup>

6 **Q. Does the Company's re-pricing proposal require Washington customers to pay**  
7 **rates that reflect policy decisions made by other states?**

8 A. No. Re-pricing the QF PPAs at Washington avoided cost prices mitigates concerns  
9 that the avoided cost prices for the QF PPAs are driven by policy choices made by  
10 other states. The use of the avoided cost pricing for QF PPAs is intended to keep  
11 customers indifferent to the QF transaction. If the QF PPAs are re-priced at the  
12 amount that this Commission has found will result in customer indifference, then  
13 customers will be no better or worse off than they would be without the QF PPA.  
14 The parties' concerns that the re-pricing proposal still reflects other state's policy  
15 decisions has merit only if one assumes that the Commission's avoided cost prices are  
16 excessive. The re-pricing proposal, therefore, ensures that Washington rates reflect  
17 only the decisions of Washington policy makers.

18 **Q. Doesn't the fact that customers rates will increase by \$7.6 million under your re-**  
19 **pricing alternative suggest that the parties' concern has merit?**

20 A. No. The fact that customer rates will increase if they pay the avoided cost prices  
21 determined by the Commission suggests that situs assignment of California and

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<sup>37</sup> Testimony of David C. Gomez, Exhibit No. DCG-1CT at 15-16; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 29-30.

<sup>38</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 30.

1 Oregon QF PPAs has allowed Washington customers to receive benefits for which  
2 they have not paid.

3 **Q. Is there any precedent for this type of re-pricing?**

4 A. Yes. As discussed above, the Commission used this approach in the 1983  
5 Washington Water Power case relied on by Staff. It is also my understanding that the  
6 North Carolina Utilities Commission (NCUC) took this same approach to a QF PPA  
7 that was approved by the Virginia State Corporation Commission (VSCC). The  
8 NCUC analyzed the QF PPA and concluded that the pricing exceeded the utility's  
9 actual avoided costs.<sup>39</sup> The NCUC therefore denied cost recovery of the amount that  
10 the NCUC found to be greater than the utility's avoided costs. It is my understanding  
11 that on judicial review, the North Carolina Supreme Court affirmed the NCUC's  
12 order, concluding that the disallowance "does not violate PURPA to the extent it only  
13 excludes the amount *above* avoided costs."<sup>40</sup>

14 I also understand that the OPUC approved a stipulation for Idaho Power  
15 Company that required Idaho Power to re-price its Idaho QF PPAs to reflect Oregon's  
16 non-levelized pricing policy.<sup>41</sup>

17 **Q. Has any party alleged that the Washington avoided cost prices used in the re-**  
18 **pricing alternative proposal do not accurately reflect the Commission's avoided**  
19 **cost prices in effect at the time the out-of-state QFs were executed?**

20 A. No. There is no basis in the record to conclude that the re-pricing does not reflect the

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<sup>39</sup> *Re N. Carolina Power*, E-22, SUB 333, 1993 WL 216264 (Feb. 26, 1993) *aff'd sub nom. N. Carolina Power*, 450 S.E.2d 896.

<sup>40</sup> *State ex rel. Utilities Comm'n v. N. Carolina Power*, 338 N.C. 412, 450 S.E.2d 896, 900 (1994). Importantly, as I discuss above, since this case, FERC has been clear that PURPA prohibits inflating the avoided cost price as the VSCC apparently did to promote state policies.

<sup>41</sup> *Re Idaho Power Co.*, Docket No. UE 257, Order No. 13-166 (May 6, 2013).

1 costs that would have been incurred if the out-of-state QF PPAs had been executed in  
2 Washington.

3 **Q. Staff and Boise both reject the Company's alternative load decrement proposal**  
4 **because they claim it is based on power flows, not cost causation.<sup>42</sup> How do you**  
5 **respond?**

6 A. The load decrement approach is consistent with cost causation. No party disputes that  
7 the out-of-state QFs serve Washington customers. Washington customers, however,  
8 are not paying their fair share of the costs by paying only current market prices. The  
9 load decrement alternative is intended to account for this fact by allocating additional  
10 costs to Washington to reflect the benefits Washington customers receive.

11 **Q. Boise claims that the load decrement approach is unreasonable because it would**  
12 **assign more transmission costs to Washington customers even though the**  
13 **presence of QFs in California and Oregon does not reduce those states' use of**  
14 **the Company's transmission network.<sup>43</sup> Does this claim have merit?**

15 A. No. Again, no party disputes that the QFs located in California and Oregon serve  
16 Washington customers. As discussed above, Boise's trade group, ICNU, previously  
17 testified before the OPUC that distributed generation, like the out-of-state QFs,  
18 typically decreases the need for transmission because the electricity is generated  
19 closer to load. This is particularly true for the out-of-state QFs because they are  
20 typically located closer to California and Oregon load and therefore use less  
21 transmission to serve that load. So it is reasonable to credit out-of-state customers for  
22 reduced transmission usage due to the QF development in those states.

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<sup>42</sup> Testimony of David C. Gomez, Exhibit No. DCG-1CT at 15; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 29.

<sup>43</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 29.

1 **Q. Boise claims that it would be unjust, unreasonable, and illegal to include the**  
2 **costs of the out-of-state QF PPAs in rates, in part, because the Commission does**  
3 **not have jurisdiction over the QFs.<sup>44</sup> Is it your understanding that the**  
4 **Commission must have jurisdiction over PPA counterparties to allow cost**  
5 **recovery of the PPAs in rates?**

6 A. No. Most, if not all, of the Company's long-term PPAs are with counterparties that  
7 are not public utilities regulated by the Commission. Nevertheless, the costs of these  
8 PPAs are regularly recovered in rates. In addition, PURPA specifically exempts QFs  
9 from regulation by state utility commissions.

10 **Q. What is the Company's recommended treatment of the costs associated with**  
11 **California and Oregon QF PPAs in west control area NPC?**

12 A. The Company recommends that the Commission allow the Company to include the  
13 costs of California and Oregon QF PPAs in west control area NPC in the same  
14 manner as all other west control area generation resources, with a portion of the costs  
15 allocated to Washington customers. Alternatively, the Company proposes the out-of-  
16 state QF PPAs be re-priced using Washington avoided cost prices and then included  
17 in the determination of west control area NPC or that the Commission adopt the  
18 proposed load decrement adjustment.

19 **Energy Imbalance Market**

20 **Q. Please describe Boise's adjustment to NPC related to the EIM.**

21 A. Boise proposes to reduce Washington NPC by more than \$5 million based on the  
22 Company's participation in the EIM, while also including certain EIM-related costs.  
23 Boise proposed this NPC reduction in October 2014 before the EIM even began

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<sup>44</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 25.

1 actual binding operations in November 2014. The adjustment is highly speculative,  
2 especially under the WCA, and improper under Washington's known and measurable  
3 standard.

4 ***EIM Background and Status***

5 **Q. What is the EIM?**

6 A. The EIM is a real-time market administered by a single market operator, the CAISO.  
7 The EIM uses an economic dispatch model to issue instructions to participating  
8 generating resources to meet the load for the entire EIM footprint. By participating in  
9 the EIM, the Company expands the CAISO's security-constrained, least-cost dispatch  
10 for most of California to include PacifiCorp's six-state platform, including additional  
11 portions of California, as well as Idaho, Oregon, Utah, Washington, and Wyoming.

12 **Q. When did the CAISO and PacifiCorp initiate the EIM?**

13 A. In February 2013, PacifiCorp and the CAISO announced a memorandum of  
14 understanding on the EIM, culminating work that began in fall 2012 when the  
15 Western Interstate Energy Board's PUC EIM Group (composed of utility  
16 commissioners from 12 states, including Washington) requested proposals for a real-  
17 time imbalance market.

18 **Q. Why did the Company decide to move forward with the CAISO to participate in  
19 the EIM?**

20 A. Developing the EIM using the CAISO's proven state-of-the-art technology and large  
21 market platform was more cost-effective, more efficient, and involved less risk than  
22 creating an entirely new model.

1 **Q. What benefits does PacifiCorp hope to achieve for customers from the EIM?**

2 A. The expected benefits of an EIM include (1) the economic efficiency of an automated  
3 five and 15 minute dispatch, (2) savings due to diversity of loads and variable  
4 resources in the expanded footprint, and (3) reduced operational risk from enhanced  
5 system reliability. The EIM should enhance reliability, more efficiently integrate  
6 renewable resources, and reduce costs for customers.

7 **Q. Are the EIM's benefits a function of the size and scope of its footprint?**

8 A. Yes. The EIM's viability and benefits come from combining the Company's  
9 transmission system, now the largest system owned by a single entity in the west,  
10 with the CAISO's system, which covers most of California. The benefits of the EIM  
11 are expected to increase as new utilities join, and NV Energy is slated to join the EIM  
12 in late 2015. Conversely, if PacifiCorp or the CAISO limited their participation in the  
13 EIM, its viability and benefits would be diminished.

14 **Q. What is the current status of EIM implementation?**

15 A. The EIM had a "soft start" on October 1, 2014. After running the EIM for a month  
16 under non-binding conditions, the market became financially binding on November 1,  
17 2014.

18 ***General Objections to EIM Benefit Imputation***

19 **Q. Did the Company include EIM costs or forecasted NPC benefits in this case?**

20 A. No. As stated in my direct testimony, the Company did not include EIM costs or  
21 benefits in this case. While EIM costs for the rate period are generally ascertainable,  
22 it is impossible at this point to accurately project the amount of offsetting benefits in  
23 the rate period. Following Washington's known and measurable standard and its



1 adherence to the matching principle, the Company elected to exclude both EIM costs  
2 and benefits from this case. For this reason, the Company did not include a request  
3 for a prudence determination for its participation in the EIM in this case.

4 **Q. Why can't the Company project EIM benefits for the rate period?**

5 A. The EIM's real-time market is the first of its kind in the west. The EIM is unlike  
6 other forecast items in this case because there is no actual or analogous historical data  
7 on which to base an economic forecast for ratemaking purposes. In addition, given  
8 the EIM's new and untested nature, the Company expects that a reasonable ramp-up  
9 period will be required before EIM benefits are fully realized.

10 **Q. Does the EIM report upon which Boise relies for its adjustment in this case  
11 analyze the EIM's benefits after the 2015-2016 start-up period?**

12 A. Yes. Boise's adjustments are almost exclusively based on the E3 Report, which  
13 analyzes EIM benefits beginning in 2017. The E3 Report was issued in March 2013,  
14 based on dated information and assumptions.

15 **Q. Does Washington's use of the WCA further complicate the projection and  
16 assignment of EIM costs and benefits to Washington?**

17 A. Yes. The WCA requires a second set of speculative projections regarding the  
18 potential costs and benefits during the start-up phase of a hypothetical EIM limited to  
19 PacifiCorp's west control area. Even assuming an EIM using only one of the  
20 Company's balancing authority areas was viable, because the expected benefits of the  
21 EIM are correlated to its scale, a hypothetical WCA-only EIM will produce  
22 proportionately less benefits than a full-system EIM.

1           In addition, the benefits of the EIM and the manner in which it will deploy the  
2           Company’s integrated system resources calls into question the fundamental  
3           assumptions underlying the WCA. The premise of the WCA is that the resources in  
4           the east control area provide little to no direct or indirect benefits to Washington. The  
5           EIM, however, will produce benefits based on the optimization of the Company’s  
6           entire system—both west and east control area resources. Given that the Commission  
7           has concluded that the east-side resources provide no benefits to Washington, it is  
8           reasonable to also conclude that the optimization of those resources through the EIM  
9           provide no benefits to Washington. Thus, the imputation of EIM benefits in this case  
10          is incompatible with the WCA.

11   **Q.    Is the Company’s approach to the EIM in this case generally similar to the**  
12    **approach adopted in other jurisdictions?**

13    A.    Yes. In Oregon, the Company and intervenors agreed to set EIM benefits included in  
14    NPC for Oregon in 2015 equal to EIM costs. In that case, Mr. Mullins was the  
15    witness for Boise’s energy trade association ICNU and testified that the Oregon EIM  
16    settlement was reasonable given the difficulty of quantifying EIM benefits in 2015.<sup>45</sup>  
17    The Company’s proposal here effectively produces the same result as the Oregon  
18    settlement supported by Mr. Mullins.

19           In Utah, the Company and intervenors agreed to a settlement where EIM  
20    benefits were excluded from NPC and allowed to pass through the Company’s energy  
21    balancing account.

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<sup>45</sup> *In re PacifiCorp*, OPUC Docket Nos. UE 287 and UM 1689, Joint Testimony in Support of Stipulation at 8, 12 (Aug. 14, 2014) (“The Settling Parties agree that, at this time, the costs and benefits associated with the EIM are difficult to predict with certainty. As an interim approach, the Settling Parties agree that it is reasonable to offset EIM costs and benefits in 2015 NPC.... [O]ffsetting the costs and benefits associated with the EIM appropriately balances possible risks and benefits during the first full year of the EIM’s operation.”).

1 **Q. What are the specific EIM benefits alleged by Boise?**

2 A. Boise alleges four distinct types of benefits, three of which were identified in the  
3 E3 report: inter-regional dispatch, intra-regional dispatch, and reserve diversity.  
4 Boise included an additional category called “within-hour dispatch.” Boise’s  
5 combined EIM adjustments reduce west control area NPC by \$21.8 million, or  
6 \$5.1 million on a Washington-allocated basis.

7 **Q. Do you have an overarching criticism of Boise’s proposed adjustments to NPC**  
8 **for EIM benefits?**

9 A. Yes. Boise relies primarily on the results of the E3 Report without regard to its  
10 applicability to the specific pro forma period in this case or the WCA methodology.  
11 The adjustments include benefits that are already reflected to some extent in the  
12 Company’s existing forecast. Furthermore, Boise’s adjustments reflect a reduction in  
13 imbalance costs that are not included in the GRID model forecast or customers’ rates  
14 to begin with.

15 **Q. Is the E3 Report, on which the Company based its decision to pursue the EIM,**  
16 **appropriate for use in ratemaking?**

17 A. No. The Company used the E3 Report to verify that the EIM would be cost effective,  
18 not as a study to quantify its near-term benefits for ratemaking. The E3 Report is  
19 based on a WECC-wide forecast for 2017, with corresponding loads and market  
20 prices, though the benefits are adjusted to 2012 dollars. The benefits determined by  
21 the E3 Report are thus dependent on the costs of system operation in 2017 and do not  
22 reflect costs included in the Company’s forecasted NPC. Differences include  
23 essential assumptions no party would accept for use in GRID in this rate case

1 including different test period, forward price curves, transmission topology, and  
2 differences in the underlying production dispatch model and associated model  
3 architecture.

4 In this way, the E3 Report is comparable to an Integrated Resource Plan,  
5 which is a planning study that is not used for ratemaking. In the Commission's  
6 November 2013 letter acknowledging the Company's 2013 Integrated Resource Plan,  
7 the Commission specifically recognized that "it is too early in the process for the  
8 Company to project the exact impacts that the EIM will have on [PacifiCorp's]  
9 strategy and its ratepayers."<sup>46</sup>

10 **Q. Boise contends the Company should use its best forecast in establishing NPC for**  
11 **the pro forma period. Do you agree?**

12 A. Yes.

13 **Q. Will all of the resources that were assumed to be bid into the EIM in 2017 in the**  
14 **E3 Report be available to be bid into the EIM during the pro forma period?**

15 A. No. The majority of natural gas resources, some wind resources, and some coal  
16 resources were available to be bid into the EIM beginning November 1, 2014.  
17 Additional resources will be available to be bid into the EIM as planned outages  
18 occur during 2015 and 2016 and required upgrades can be completed. Exhibit  
19 No. GND-7 identifies the resources that were available to bid into the EIM as of  
20 November 11, 2014. As seen in the exhibit, the majority of the resources are not  
21 included in the west control area.

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<sup>46</sup> *PacifiCorp's 2013 Electric Integrated Resource Plan*, Docket No. UE-120416, Commission Acknowledgement Letter (Nov. 25, 2013).

1 **Q. What is the Company's best forecast of EIM benefits for the pro forma period?**

2 A. The Company does not have a good forecast of EIM benefits based on known and  
3 measurable data comparable to other inputs into the GRID model used to project NPC  
4 in base rates.

5 **Q. Apart from modeling debates, what else should the Commission consider in  
6 deciding whether to include EIM benefits in rates?**

7 A. As noted above, there is further upside potential in the form of lower costs and  
8 enhanced reliability for customers if other balancing authorities join the EIM. If the  
9 Commission's action in this proceeding is perceived to be a penalty to the Company  
10 for taking an innovative leadership action to reduce customer costs, the likelihood of  
11 other utilities joining the EIM, or at least speed at which other utilities join, will  
12 diminish, thereby diminishing the likelihood of increased benefits. Imputing benefits  
13 into rates that exceed a reasonable known and measurable standard would be viewed  
14 by any utility as a penalty and would provide a strong disincentive to utilities seeking  
15 innovative ways to reduce their costs.

16 **Q. Is it reasonable to make line-by-line adjustments to the various items in the  
17 E3 Report to adjust for the uncertainty and non-matching aspects of the E3  
18 Report to the rate case?**

19 A. No. The Company does not support using a discounted approach to the E3 Report to  
20 arrive at an appropriate forecast of EIM benefits to use in setting in rates. Any  
21 judgment applied to arrive at a discount would necessarily be highly subjective.  
22 Nonetheless, the Company provides additional discussion of risks and uncertainties

1 associated with the line items in the E3 Report to further support the Company's  
2 position against imputation of forecast EIM benefits in this case.

3 **Q. Are there other studies that could provide insight on expected EIM benefits?**

4 A. No. Boise cites a Southwest Power Pool (SPP) study that found first-year SPP EIM  
5 benefits were 20 percent higher than forecast.<sup>47</sup> But the study summary indicates—  
6 and Boise neglects to mention—that this was primarily attributed to higher gas prices  
7 than were assumed in the forecast. Thus, to the extent market prices, hydro  
8 conditions, resource availability, transfer capability, and loads differ from the levels  
9 assumed in the E3 Report, the EIM benefits will be impacted.

10 ***Objections to Imputing Benefits for EIM Inter-Regional Dispatch***

11 **Q. What inter-regional dispatch benefits are contemplated in the EIM?**

12 A. Inter-regional dispatch reflects the value of energy transactions between the CAISO  
13 and PacifiCorp. As a result of the EIM, CAISO and PacifiCorp are expected to be  
14 able to transact more frequently using transmission capacity between CAISO and  
15 PacifiCorp at the California-Oregon Intertie (COI). Inter-regional dispatch benefits  
16 result when CAISO and PacifiCorp can transact at a higher sale price and lower  
17 purchase price with each other than is available from their internal resources. The  
18 Company would be both a buyer and a seller at different times, depending on system  
19 conditions.

20 Inter-regional benefits are highly dependent upon transfer capability between  
21 the CAISO and PacifiCorp. The E3 Report evaluated benefits from a range of  
22 100 MW to 800 MW of bi-directional five-minute dynamic transfer capability  
23 between CAISO and PacifiCorp at the COI. In practice, due to constraints imposed

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<sup>47</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 34.

1 by the Bonneville Power Administration, who is the path operator on the north side of  
2 COI, the EIM transfers result from a combination of five-minute and 15-minute  
3 market instructions. Currently and temporarily, however, this transfer capability has  
4 been limited to 15-minute EIM transfers on a basis up to approximately 400 MW bi-  
5 directional.<sup>48</sup> These 15-minute transfers are not as valuable as five-minute dynamic  
6 transfers and do not correlate to the E3 Report as Boise suggests.

7 **Q. Does the Company's pro forma NPC already reflect certain inter-regional**  
8 **dispatch benefits?**

9 A. Yes. The Company's filing includes 108 aMW of transactions delivered to the  
10 California-Oregon Border (COB) market and 20 aMW of transactions received from  
11 the COB market. These transactions use the same transmission capacity  
12 contemplated for inter-regional transfers in the E3 Report. The majority of the  
13 transactions reflect system balancing decisions by the GRID model, which optimizes  
14 the dispatch of PacifiCorp generation against market transactions, much like what  
15 will occur under the EIM.

16 **Q. Do you agree with Boise's proposal to allocate the inter-regional dispatch**  
17 **savings between the Company's west and east control areas in proportion to the**  
18 **load of each control area?**<sup>49</sup>

19 A. No. The inter-regional dispatch benefit has no direct relationship to load, as it is a  
20 result of changes in generation dispatch and associated market transactions. The  
21 Company's east control area has more dispatchable generation with a range of fuel

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<sup>48</sup> Up to 432 MW southbound and 331 MW northbound for the combination of five-minute dynamic and 15-minute static scheduling. These values are further limited at times due to planned and unplanned transmission outages.

<sup>49</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 35.

1 costs from low-cost coal through high-heat-rate peaking gas plants. As a result, the  
2 east control area will frequently have some units that are close to the system  
3 incremental cost and could benefit from EIM dispatch. On a total-company basis,  
4 46 percent of the Company's resource need for 2015 is expected to be met by  
5 generation currently being dispatched within the EIM. The west control area is more  
6 heavily dependent on market transactions, so there may be fewer opportunities for  
7 EIM redispatch of west control area resources. Only 24 percent of the Company's  
8 west control area resource need in the pro forma period is expected to be met by  
9 generation dispatched within the EIM. In addition, Boise's adjustment is based solely  
10 on the E3 Report outcome, and does not incorporate the associated transaction  
11 volumes or any generation impacts in the GRID model, so it is unclear how the  
12 benefits are expected to materialize. Since it is lacking a concrete demonstration of  
13 the expected benefits, this aspect of Boise's adjustment is clearly not known and  
14 measurable and should be rejected.

15 ***Objections to Imputing Benefits for EIM Intra-Regional Dispatch***

16 **Q. How was the intra-regional dispatch benefit calculated in the E3 Report?**

17 A. Before April 1, 2009, the CAISO operated under zonal pricing, with units committed  
18 based on the zonal prices that ignored transmission constraints, but dispatched based  
19 on the actual transmission capability. Starting on April 1, 2009, the CAISO operated  
20 with nodal pricing, with both commitment and dispatch decisions based on actual  
21 transmission capabilities. A study of the market outcomes before and after the  
22 transition found an estimated annual cost reduction of \$105 million as a result of the



1 transition to nodal pricing.<sup>50</sup> To estimate the savings to the Company, the E3 Report  
2 pro-rated the result based on the CAISO peak load at the time of the study and the  
3 Company's peak load in 2017.

4 **Q. Is the CAISO system comparable to the Company's system?**

5 A. No. In 2009, the CAISO system had 258 natural gas generators, whereas the  
6 Company has just twelve, only three of which are in the west control area. That  
7 represents just one percent as many natural gas plants in the west control area  
8 compared to the CAISO, so pro-rating the estimated benefits of dispatching those gas  
9 plants based on a west control area load share of approximately seven percent likely  
10 overstates the potential benefits.

11 **Q. Does the Company's pro forma NPC incorporate the costs of zonal pricing, i.e.  
12 ignoring transmission constraints?**

13 A. No. The Company's pro forma NPC are developed using the GRID model, which  
14 already employs nodal dispatch. As with the model used in the E3 Report, GRID  
15 assumes perfectly efficient operations: subject to transmission constraints, in every  
16 hour the lowest cost resources will be dispatched. In addition, the Company's gas  
17 plant "screening" process optimizes the commitment of each gas unit based on its  
18 actual contribution to system costs, accounting for the nodal value at the point of  
19 delivery, rather than based on prices at a potentially distant regional market point.  
20 Therefore, the Company's pro forma NPC already incorporates intra-regional  
21 dispatch savings compared to the Company's actual operations. Boise's criticism of

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<sup>50</sup> Frank A. Wolak, 2011, "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets, *American Economic Review* 101: 247-252. Accessed November 13, 2014: [http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/benefits\\_of\\_spatial\\_granularity\\_aer\\_wolak.pdf](http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/benefits_of_spatial_granularity_aer_wolak.pdf)

1 the Company's current generator dispatch practices is irrelevant because the costs  
2 associated with those practices are not reflected in the Company's pro forma NPC.  
3 While the Company may experience benefits from EIM in its actual operations, those  
4 benefits will only bring actual costs closer to the ideal dispatch calculated in the  
5 GRID model.

6 **Q. What evidence does Boise provide in support of its intra-regional dispatch  
7 adjustment?**

8 A. Boise provides no evidence related to the changes in the Company's commitment and  
9 dispatch practice as a result of EIM implementation. Instead, Boise calculates the  
10 benefits of allowing the GRID model to make unlimited system balancing sales at the  
11 COB and Mid-Columbia markets.<sup>51</sup> Increasing market transactions between CAISO  
12 and the Company is irrelevant to intra-regional benefits since they are unaffected by  
13 the transfer capability between CAISO and the Company. Initially, the Company  
14 only anticipates EIM interchange at COB, so it is unclear why Boise expects the EIM  
15 to create opportunities for additional bilateral transactions at other market hubs.  
16 While NV Energy has expressed interest in joining the EIM, no other parties have  
17 made commitments to join and it is unlikely another party could enter the EIM before  
18 the end of the pro forma period in this proceeding. Even if an additional party joins  
19 the EIM, the Company would receive inter-regional dispatch benefits as a result of  
20 additional transaction opportunities, not intra-regional dispatch benefits.

21 **Q. Please summarize your position regarding the intra-regional dispatch  
22 adjustment.**

23 A. Boise's intra-regional dispatch adjustment has little relation to the cost savings by the

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<sup>51</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 39.

1 same name calculated in the E3 Report. The E3 Report found fuel cost savings as a  
2 result of using more efficient generators and accounting for transmission constraints  
3 in the decision to start up a resource, both of which are already accounted for in the  
4 Company's pro forma NPC. Boise found cost savings by allowing for unlimited  
5 market transactions up to transmission limits, which better describes the inter-  
6 regional dispatch adjustment described above. Boise presents no evidence that  
7 unlimited market transactions are reasonable, double-counts the benefits of increased  
8 market transactions, and provides no evidence that the Company's forecasted intra-  
9 regional dispatch costs are overstated, either with or without EIM. For those reasons  
10 Boise's adjustment should be rejected.

11 ***Objections to Imputing Benefits for EIM Reserve Diversity***

12 **Q. What are the benefits of flexible reserve diversity as contemplated in the EIM?**

13 A. Flexibility reserve benefits reflect the benefit of reduced flexibility reserve  
14 requirements over the combined EIM footprint. Like inter-regional benefits,  
15 flexibility reserve benefits are highly dependent upon transfer capability between the  
16 CAISO and PacifiCorp.

17 **Q. How is the flexibility reserve diversity benefit allocated in the E3 Report?**

18 A. The Company's share of the flexibility reserve diversity benefit is allocated based on  
19 the ratio of the Company's stand-alone reserve requirement to the total reserve  
20 requirement of the Company and the CAISO without the EIM.

21 **Q. How much flexibility reserve diversity benefit did the E3 Report predict?**

22 A. According to the E3 Report, PacifiCorp's flexibility reserve requirements will be  
23 reduced by 19 MW under the 100 MW transfer capability scenario, and by 78 MW

1 under the 400 MW transfer capability scenario. These values reflected the E3 Report  
2 assumption that only 80 percent of the theoretical reserve savings could be achieved  
3 given the five-minute granularity of the EIM market. Reserves needed over shorter  
4 time frames would have to be provided with internal resources.

5 **Q. Are flexibility reserve diversity benefits currently expected to be lower than**  
6 **predicted in the E3 Report?**

7 A. Yes. At present, most of the Company's EIM transfer rights only allow for 15-minute  
8 static transfers, so the reserve diversity savings will be lower than with five-minute  
9 transfers that form the basis of the E3 estimate.

10 **Q. How much flexibility reserve savings does Boise predict for the west control**  
11 **area?**

12 A. Boise assumed that 100 percent of the theoretical reserve savings would be achieved  
13 and allocated these benefits to the west control area based on the ratio of west control  
14 area load to system load.<sup>52</sup>

15 **Q. Is it appropriate to allocate flexible reserve benefits to the west control area**  
16 **based on load?**

17 A. No. This overstates the total reserve savings and overstates the savings that will be  
18 allocated to the west control area. The E3 Report and CAISO EIM business practice  
19 allocate the flexibility reserve benefit based on the reserve need under independent  
20 operation. Because the east control area has more wind resources, it has a relatively  
21 larger share of the flexibility reserve requirement and would be allocated a larger  
22 share of the flexibility reserve benefit.

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<sup>52</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 40-42.

1 ***Objections to Imputing Benefits for Within-Hour Dispatch***

2 **Q. Please describe Boise's within-hour dispatch benefit adjustment.**

3 A. Boise reduces the regulating reserves in the pro forma period to the 30-minute level  
4 projected in the Company's 2012 Wind Integration Study (Wind Study).<sup>53</sup> This  
5 reduces the reserves held for the west control area by 30 percent, or 53 MW. Boise  
6 claims this to be the within-hour dispatch benefit adjustment.

7 **Q. First, please describe the basic calculation errors in Boise's adjustment.**

8 A. Boise's calculation removes a portion of the frequency response reserves associated  
9 with WECC standard BAL-003-1. These reserves cover frequency variation, rather  
10 than energy imbalance, and thus will not be impacted by a shorter balancing interval.  
11 Boise's calculation also overstates the reserve savings by double-counting the March  
12 reserve requirement, which is the highest of any month.

13 **Q. Please explain the additional problem with Boise's proposed adjustment.**

14 A. Boise's proposed within-hour dispatch benefit adjustment is fatally flawed because it  
15 repeatedly counts the same benefits that are already captured in the three categories  
16 previously described.

17 • Boise's within-hour dispatch adjustment is derived by using capacity held for  
18 reserves to make additional market transactions. These are the same reserves  
19 addressed in the inter-regional dispatch and flexibility reserve adjustments also  
20 proposed by Boise. By taking one result from the E3 Report and a second result  
21 using the same components from GRID, Boise has double-counted the associated  
22 benefits.

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<sup>53</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 42-43.

- 1           • The flexibility reserve savings in the E3 Report are dependent on the level of  
2           reserves required. If the Company’s reserve requirement were reduced, as  
3           proposed in Boise’s within-hour dispatch adjustment, the total flexibility reserve  
4           savings, and the Company’s share of those savings, would also be reduced.
- 5           • The adjustment double-counts benefits because the intra-regional benefits are  
6           based on the operation of an hourly market compared to the operation of a five-  
7           minute market based on CAISO’s experience in 2009.

8   **Q. Are within-hour savings even applicable to GRID?**

9   A. No. The GRID model does not include the costs of within-hour redispatch, and  
10   therefore within-hour savings are inapplicable to GRID. GRID is an hourly model  
11   that assumes there are no changes in loads and resources within the hour.

12   **Q. How does the Company balance its system under current operations?**

13   A. Under the current hourly scheduling process, the Company must finalize its balancing  
14   transactions with other market participants before the hour. Other than a short  
15   transition period in the first and last 10 minutes of the hour, those transaction volumes  
16   are fixed for the entire hour. As a result, the Company must dispatch its own  
17   resources to offset any changes in loads or variable generation across the hour. If  
18   load is increasing, the Company will need to back down its generation in the start of  
19   the hour and dispatch additional generation at the end of the hour. Because the lowest  
20   cost resources are dispatched first, lower cost resources will be backed down in the  
21   start of the hour, and higher cost resources will be dispatched up at the end of the  
22   hour. Load and variable generation vary continuously, and every hour will have both

1 periods that are above the hourly average and periods that are below the hourly  
2 average.

3 **Q. How would the EIM impact within-hour dispatch?**

4 A. The EIM re-dispatches the Company's resources as well as the CAISO resources  
5 every five minutes to optimally serve the combined PacifiCorp and CAISO load,  
6 subject to the EIM transmission limits.

7 **Q. What is the net result of within-hour EIM dispatch?**

8 A. PacifiCorp resources that are lower cost than CAISO resources would be dispatched  
9 to a greater extent resulting in EIM transfers from PacifiCorp to CAISO, and  
10 PacifiCorp resources that are higher cost than CAISO resources would not be  
11 dispatched as much resulting in EIM transfers from CAISO to PacifiCorp.

12 **Q. How does this net result compare to the modeled results in GRID?**

13 A. This result mimics the result calculated by GRID. As described earlier, the GRID  
14 model already includes transactions at the COB market, which use the same  
15 transmission capacity contemplated for transfers to and from CAISO in the  
16 E3 Report. The majority of the transactions reflect system balancing decisions by the  
17 GRID model, which optimizes the dispatch of PacifiCorp generation against market  
18 transactions, much like what will occur under the EIM. Because GRID has  
19 unchanging load across each hour, it is comparable to dispatching thermal resources  
20 and market transactions across twelve identical five-minute blocks in an hour—since  
21 the load is identical, the results are identical. Because GRID is able to balance the  
22 precise load across each time period using market transactions, it already reflects the  
23 benefits of within-hour market transactions. To reflect the Company's current

1 operations, i.e. without intra-hour market transactions, GRID would need to have  
2 fixed market transactions for the entire hour and have any variation in load or variable  
3 resources over each hour met by dispatching generation resources.

4 **Q. What do you recommend regarding within-hour EIM dispatch benefits?**

5 A. Boise's proposed within-hour adjustment should be rejected because it double counts,  
6 is overstated, and is intended to remove costs from GRID that were never included in  
7 the first place.

8 *Other Objections to Imputing EIM Benefits*

9 **Q. Considering all of the non-matching aspects of the E3 Report to the pro forma  
10 NPC calculated using GRID, is it reasonable to impute EIM benefits as proposed  
11 by Boise?**

12 A. No. As noted above, imputation of EIM benefits cannot be reconciled with the  
13 rationale underlying the WCA. In addition, given the restrictions on five-minute  
14 dynamic transfer capability, the benefits expected in the pro forma period in this case  
15 would most closely correspond to the low range of benefits in the E3 Report  
16 assuming 100 MW of transfer capability. The total benefits for the year 2017 under  
17 that scenario are \$10.5 million, consisting of \$7.0 million for inter-regional dispatch,  
18 \$2.3 million for intra-regional dispatch, and \$1.2 million for flexibility reserves. That  
19 amount would need to be further reduced to reflect a phased-in ability for the  
20 Company's generating units to bid into the EIM as compared to the same assumption  
21 in the E3 Report.

22 The E3 Report does not reflect matching assumptions in this rate case  
23 including a different test period, forward price curves, transmission topology, and



1 differences in the underlying production dispatch model and associated model  
2 architecture. Furthermore, the purpose and design of the EIM is to optimize the  
3 Company's system dispatch across its entire footprint, not just the west control area.  
4 Considering these facts and other points I have made in my rebuttal testimony,  
5 I conclude that the Company's proposal to exclude the benefits, and also the costs, of  
6 EIM from this case is reasonable.

7 **Inter-Hour Integration**

8 **Q. Please explain Boise's adjustment related to inter-hour integration of wind and**  
9 **load.**

10 A. Boise argues that the new methodology for including the shape of wind generation in  
11 GRID already reflects actual hour-to-hour variability and that calculating inter-hour  
12 integration costs outside of GRID means that the Company is double-counting the  
13 inter-hour integration costs in the NPC.<sup>54</sup> Boise argues the same rationale applies to  
14 the hourly load forecast included in GRID, and that the inter-hour load integration  
15 costs should also be removed.

16 **Q. How does Boise describe system balancing wind integration?**

17 A. Boise describes system balancing wind integration costs as the system costs  
18 associated with the hour-to-hour variability in wind output.<sup>55</sup> Boise claims that the  
19 increase in NPC due to introducing wind variability is the same as the inter-hour  
20 integration cost added to NPC by the Company.

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<sup>54</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 47.

<sup>55</sup> *Id.*

1 **Q. Do you agree that the increase in NPC due to wind variability is the same as**  
2 **inter-hour integration?**

3 A. No. Boise's basic assumptions underlying this adjustment are flawed and the  
4 adjustment is meritless.

5 **Q. Can you please further explain the cost of inter-hour wind integration?**

6 A. Yes. The Company must commit generation resources (*i.e.*, select start-up and  
7 shutdown times for the next day), based on a forecast of load and wind generation and  
8 considering wholesale market prices, but must dispatch those resources to balance the  
9 actual load and wind conditions that occur in real time. In the Company's Wind  
10 Study, this inter-hour integration, or system balancing, cost is calculated by  
11 comparing the NPC from two studies. In the first study, the economic unit  
12 commitment is determined including the day-ahead forecast and the system is  
13 balanced around the forecast wind output. In the second study, the economic units'  
14 commitment remains based on the day-ahead forecast, but the system must balance  
15 around the actual wind output. Costs are higher in the second study because the unit  
16 commitment is optimized against wind output that is different from what actually  
17 occurs. The Wind Study determined this cost to be 36 cents (in 2012 dollars) per  
18 megawatt-hour of wind generation and this cost is added to the Company's NPC  
19 results.<sup>56</sup>

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<sup>56</sup> PacifiCorp 2013 Integrated Resource Plan, Volume II, Appendix H—Wind Integration Study, Table H.2.  
Available online at:  
[www.pacificorp.com/content/dam/pacificorp/doc/Energy\\_Sources/Integrated\\_Resource\\_Plan/2013IRP/PacifiCorp-2013IRP\\_Vol2-Appendices\\_4-30-13.pdf](http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf)

1 **Q. Is the hour-to-hour variability included in the Company's wind generation**  
2 **forecast the same issue as measured by the Wind Study?**

3 A. No. The Wind Study measures the impact of committing generation resources  
4 considering a forecast of wind generation and then dispatching those resources when  
5 actual generation is different than forecast. The Company's filed GRID study uses  
6 the same wind shape to determine unit commitment and final dispatch, so the costs  
7 associated with less-than-optimal day-ahead unit commitment are not included in the  
8 GRID model. Clearly, Boise's claim that the cost of using the actual wind shape  
9 during each hour in GRID, rather than using a less volatile shape, is the same as  
10 including costs borne from committing generation resources against forecasted load  
11 and wind generation and then dispatching generation resources under actual load and  
12 wind conditions as they occur in real time is incorrect.

13 **Q. Is it appropriate to include both inter-hour integration costs and an hourly wind**  
14 **shape?**

15 A. Yes. As describe above, the Company's filed GRID study uses the same wind shape  
16 to determine unit commitment and final dispatch, so the costs associated with less-  
17 than-optimal day-ahead unit commitment are not included within the GRID model.  
18 Therefore the Company's continued application of this cost outside of the GRID  
19 model is appropriate and is in keeping with the basis for these expenses in the 2012  
20 Wind Study.

1 **Q. Are inter-hour load integration costs derived in the same manner as system**  
2 **balancing wind integration costs?**

3 A. Yes. Both of these costs result from the unpredictable nature of load and wind on a  
4 day-ahead basis and committing generation resources against a forecast and then  
5 dispatching generation resources under actual conditions. The Wind Study accounted  
6 for the inter-hour integration costs associated with load using the same methodology  
7 as for wind, by calculating unit commitment based on the day-ahead load forecast,  
8 and system costs based on the actual load.

9 **Q. Do costs caused by variations between day-ahead and actual wind and those**  
10 **caused by load impact the Company's system differently?**

11 A. No. An increase in load and a decrease in wind generation in the same area both  
12 require additional generation or replacement market power, and both impact the level  
13 of reserves the Company is required to hold.

14 **Q. Is this the first time the Company included inter-hour load integration charges**  
15 **in NPC?**

16 A. No. In the 2010 Wind Integration Study, the reported system balancing cost for wind  
17 reflected the cost of day-ahead forecast errors for both wind and load. The costs  
18 associated with both wind and load errors were divided by the wind generation in the  
19 study resulting in a total cost averaging \$0.86 per megawatt-hour of wind  
20 generation.<sup>57</sup> This issue was identified in stakeholder comments on the 2010 Wind  
21 Integration Study, and in the 2012 Wind Study the methodology was revised to

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<sup>57</sup> PacifiCorp 2013 Integrated Resource Plan, Volume II, Appendix H - Wind Integration Study. Table H.2.  
Available online at:  
[www.pacificorp.com/content/dam/pacificorp/doc/Energy\\_Sources/Integrated\\_Resource\\_Plan/2013IRP/PacifiCorp-2013IRP\\_Vol2-Appendices\\_4-30-13.pdf](http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf)

1 distinguish between wind and load, which resulted in the lower inter-hour wind  
2 integration cost of \$0.36 per megawatt-hour. Because the 2010 Wind Integration  
3 Study results were used in Docket UE-111190, inter-hour costs for load have already  
4 been reflected in rates in the past.

### 5 **RENEWABLE RESOURCE TRACKING MECHANISM**

6 **Q. Please summarize the Company's proposed RRTM.**

7 A. The RRTM is designed to allow the Company to recover the costs incurred to comply  
8 with the EIA, as provided by RCW 19.285.050(2).<sup>58</sup> Consistent with Washington  
9 state policy, since the enactment of the EIA, the Company has added significant new  
10 wind resources in its west control area. The intermittent nature of these new wind  
11 resources created volatility in the Company's NPC that would not exist without these  
12 resources. To address this volatility, the Company proposed an RRTM that would  
13 allow a dollar-for-dollar true up of forecast to actual wind generation. The RRTM  
14 ensures that customers pay the actual costs associated with the energy they consume  
15 and eliminates barriers to further renewable energy development, in furtherance of  
16 Washington state policy.

17 **Q. Do parties support the Company's proposed RRTM?**

18 A. No. Parties' criticisms are similar, focusing largely on the lack of dead bands and  
19 sharing bands and the fact that the RRTM is narrowly focused on only intermittent  
20 renewable resources. In addition, even though Staff rejects the proposed RRTM,  
21 Staff proposed a PCAM as an alternative.

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<sup>58</sup> RCW 19.285.050(2) provides that an "investor-owned utility is entitled to recover all prudently incurred costs associated with compliance with this chapter."

1 **Q. Please respond to the Staff's proposed PCAM.**

2 A. The Company appreciates Staff making a PCAM proposal in recognition of the fact  
3 that the Company is the only energy utility in Washington without such a mechanism.  
4 But Staff's PCAM does not address the under-recovery of renewable resource costs  
5 or negate the need for the RRTM. The Company cannot accept Staff's proposed  
6 PCAM in lieu of the RRTM because it insufficiently addresses the issues facing the  
7 Company, including the significant variability and unpredictability of renewable  
8 generation.

9 **Q. Are the Company's proposed RRTM and a PCAM incompatible with one**  
10 **another?**

11 A. Not necessarily. For example, the OPUC just opened a generic investigation into the  
12 reasonableness of treating the variable costs of renewable resources differently than  
13 other variable power costs under utility PCAMs.<sup>59</sup> In that case, both PacifiCorp and  
14 Portland General Electric Company are urging the OPUC to adopt an RRTM-type  
15 mechanism to operate in tandem with the companies' PCAMs.

16 **Q. Parties recommend that the Commission reject the RRTM for lack of dead**  
17 **bands or sharing bands that the Commission has required for PCAMs.<sup>60</sup> How**  
18 **do you respond?**

19 A. The RRTM is not intended to be a PCAM, although the RRTM and a PCAM can be  
20 complementary to one another. Therefore, the policies that the Commission has

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<sup>59</sup> See *In the Matter of Portland General Elec. Co. and PacifiCorp Request for a Generic Power Cost Adjustment Mechanism Investigation*, Docket No. UM 1662, Public Utility Commission of Oregon Staff Report (Nov. 5, 2014) ("Staff recommends that the Commission open an investigation into the treatment of variable costs that are a direct result of compliance with [Oregon's RPS]."). The OPUC adopted staff's recommendation and opened the investigation at its November 12, 2014 public meeting. The OPUC staff's report is available online at: <http://edocs.puc.state.or.us/efdocs/HAU/um1662hau16726.pdf>.

<sup>60</sup> See e.g. Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 6-7; Responsive Testimony of Bradley Mullins, Exhibit No. BGM-1CT at 60.

1 announced for PCAMs, which address a much broader category of costs, should not  
2 apply to the more narrowly tailored RRTM. The RRTM focuses on those resources  
3 that were procured specifically to further Washington state energy policy and reduce  
4 greenhouse gas emissions and resources that exhibit significant variability that is  
5 entirely outside the Company's control. The lack of sharing and dead bands ensures  
6 that the RRTM advances state energy policy and promotes renewable development by  
7 allowing full cost recovery for renewable resources used to serve Washington  
8 customers.

9 **Q. How does the RRTM further Washington state energy policy?**

10 A. As outlined above, Washington has made a concerted effort to promote the  
11 development of renewable resources in Washington and the Pacific Northwest.  
12 Consistent with these policies, the RRTM promotes renewable development by  
13 mitigating the cost-recovery concerns that arise due to the inherent variability of  
14 many renewable resources. With the RRTM, the Company will be well positioned to  
15 continue to develop its renewable generation portfolio to provide clean, carbon-free  
16 electricity to Washington customers.

17 **Q. Staff observes that the Commission has consistently required dead bands and**  
18 **sharing bands to encourage a utility to effectively manage its NPC and keep**  
19 **power costs low.<sup>61</sup> Will the lack of dead bands and sharing bands eliminate the**  
20 **Company's incentives to effectively manage its NPC?**

21 A. No. The justification for dead bands and sharing bands does not apply to the  
22 renewable resources subject to the RRTM because the variability exhibited by wind  
23 resources is out of the Company's control. The Company cannot control when or to

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<sup>61</sup> Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 8.

1 what extent the wind will blow and therefore cannot exercise operational control over  
2 these resources to mitigate the costs incurred when the wind blows more or less than  
3 expected. Therefore, applying dead bands and sharing bands to the RRTM is not  
4 justified.

5 **Q. Even if the Company cannot control the level of wind generation, can the**  
6 **Company control other aspects of its overall NPC through, for example,**  
7 **integrated resource planning, hedging, or dispatch of other resources to mitigate**  
8 **the impact of wind variability?**

9 A. Yes, but the control the Company can exercise does not mitigate the unpredictability  
10 of wind generation. It is true that the Company can control many aspects of its  
11 overall resource portfolio and system operations to efficiently manage NPC. And it is  
12 certainly true that the Company actively and efficiently operates its system to respond  
13 to the minute-by-minute changes in wind generation as they occur. However, even  
14 the most efficient system operation cannot entirely mitigate the risks and costs  
15 associated with the variable and unpredictable nature of wind generation. This is  
16 particularly true when rates are set based on forecast wind generation that, as  
17 demonstrated in my direct testimony, varies significantly from actual wind  
18 generation.

19 **Q. Boise claims that the Company's overall system benefits from wind generation**  
20 **even though it is unpredictable and variable because the wind resources provide**  
21 **fuel diversity to the Company's resource portfolio.<sup>62</sup> Do you agree?**

22 A. Yes. The Company does not dispute that wind resources provide valuable resource  
23 diversity to the Company's portfolio and benefit Washington customers, but that is

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<sup>62</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 57-58.



1 not the issue that the RRTM is intended to address. The fact is that the Company has  
2 procured and will continue to procure significant wind resources specifically to  
3 comply with state energy policy. To account for the introduction of significant  
4 amounts of variable, intermittent generation, the RRTM is designed to allow the  
5 Company to recover all its prudently incurred costs—no more and no less. For this  
6 reason, the risks and benefits due to wind generation variability, caused in large part  
7 by Washington’s renewable resource procurement requirements, will fall equally—  
8 and fairly—on customers and shareholders. In this way, the RRTM ensures that  
9 Washington customers receive the full benefits and pay the full costs associated with  
10 the wind generation.

11 **Q. Staff also claims that the variation in renewable generation is “nothing more**  
12 **than normal market and weather variation, which the Commission does not**  
13 **include in PCAMs.”<sup>63</sup> How do you respond?**

14 A. The Company does not dispute that the Commission has previously stated that  
15 PCAMs are intended to capture extraordinary, not normal, power cost variability.<sup>64</sup>  
16 However, the risks associated with the Company’s renewable resources are risks  
17 created by state energy policy encouraging and requiring the development of  
18 renewable resources. Therefore, it is reasonable for Washington customers to assume  
19 the risk and costs created by Washington policy-makers.

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<sup>63</sup> Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 7.

<sup>64</sup> See, e.g. *Wash. Utils. & Transp. Comm’n v. PacifiCorp*, Docket No. UE-130043, Order 05 ¶ 172 (Dec. 4, 2013).

1 **Q. Staff claims that the majority of the variation the Company claims is due to wind**  
2 **generation is actually due to variation in market prices.<sup>65</sup> Boise makes a similar**  
3 **point.<sup>66</sup> How do you respond?**

4 A. The RRTM must account for market variability because that variability is an integral  
5 component of the cost variability associated with intermittent wind resources. The  
6 RRTM calculates the difference between the value of wind modeled in the  
7 Company's forecast NPC and the actual value of wind based on actual generation and  
8 actual market conditions. There is nothing unreasonable about factoring in market  
9 price changes because that is the most accurate way to calculate the NPC impact of  
10 variations in wind generation. And even if market variability is a component of the  
11 overall RRTM calculation, market prices, like wind generation, are outside the  
12 Company's control. Indeed, Staff has previously testified that the "Company has no  
13 control of either the sales prices or purchase prices related to economy market energy  
14 transactions it needs to make in order to address hydro-generation variability or short-  
15 term changes in customer load."<sup>67</sup> Again, the RRTM is designed to ensure that  
16 customers pay the cost of the generation used to serve them, no more and no less, and  
17 therefore it must accurately value wind generation to do so.

18 **Q. Boise claims that the Company's wind generation variability from year to year is**  
19 **not great enough to warrant the RRTM and that wind variability is, in fact, less**  
20 **than hydro variability.<sup>68</sup> How do you respond?**

21 A. Boise's analysis is incomplete because the RRTM is intended to address variability

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<sup>65</sup> Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 10.

<sup>66</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 58.

<sup>67</sup> *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-061546, Testimony of Alan P. Buckley, Exhibit No. APB-1T at 33:1-3 (Feb. 16, 2007).

<sup>68</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 54-55.

1 from forecasts to actuals, not variability from year-to-year. As I demonstrated in my  
2 direct testimony, the variability of forecast to actual generation is significant.<sup>69</sup>

3 In addition, the comparison of wind to hydro variability misses the mark  
4 because wind is more unpredictable than hydro. While it is certainly difficult to  
5 forecast hydro generation over the course of a year, there is predictability to the shape  
6 of hydro seasonally that is not present with wind. Wind generation can change from  
7 minute to minute, and because the majority of the Company's wind resources in the  
8 west control area are located in the same general area, there is little geographic  
9 diversity to mitigate changing wind conditions.

10 **Q. Has Boise previously acknowledged the difficulty in forecasting wind  
11 generation?**

12 A. Yes. In the Company's last general rate case, Docket UE-130043, Boise's NPC  
13 witness Mr. Michael Deen testified that, "Forecasting normalized annual generation  
14 for large-scale wind projects in the United States is very much a science still in  
15 development . . . it is clear that wind power resources can display a high level of  
16 variability in inter-annual generation."<sup>70</sup>

17 **Q. Staff and Boise claim that the RRTM is too narrow and should be rejected  
18 because there is uncertainty associated with all aspects of the Company's NPC  
19 and it is unreasonable to single out only renewable resources.<sup>71</sup> Please respond.**

20 A. I agree that there is uncertainty and variability related to many aspects of the  
21 Company's NPC. However, the difficulty of accurately forecasting wind generation

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<sup>69</sup> Direct Testimony of Gregory N. Duvall, Exhibit No. GND-1CT at 42 Table 7.

<sup>70</sup> *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-130043, Responsive Testimony of Michael C. Deen on behalf of Boise White Paper, LLC, Exhibit No. MCD-1CT at 9:4-6 (June 21, 2013).

<sup>71</sup> Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 12; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 55.

1 is greater than the difficulty of forecasting many other aspects of the Company’s  
2 NPC. And, unlike many other variables impacting the Company’s NPC, the wind  
3 variability is a direct result of Washington laws and policies encouraging and  
4 requiring the Company to procure specific types of resources.

5 I would also note that in past dockets, ICNU proposed a PCAM that would  
6 address only hydro variability, much in the same way that the RRTM addresses only  
7 renewable variability.<sup>72</sup> Although ICNU’s hydro-only PCAM was not adopted by the  
8 Commission, it supports the Company’s view that a cost adjustment mechanism that  
9 is narrowly focused on particular resources is reasonable.

10 **Q. Boise also quotes a brief filed by the Company in Oregon claiming that the**  
11 **Company cannot isolate the impact of wind generation from its overall NPC.<sup>73</sup>**  
12 **Does Boise’s testimony accurately portray the Company’s argument in the**  
13 **Oregon proceeding?**

14 A. No. Boise failed to provide the full excerpt from the record in Oregon. Specifically,  
15 in the Oregon proceeding, I testified that the Company could not “isolate and quantify  
16 the exact NPC impacts associated with the renewable generation.”<sup>74</sup> I then testified  
17 that the risks associated with increased renewable generation resulting from RPS  
18 obligations can be measured “based on variances in wind output and market prices  
19 actually experienced,”<sup>75</sup> which is the same methodology the Company proposed for  
20 its RRTM.

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<sup>72</sup> *Wash. Utils. & Transp. Comm’n v. PacifiCorp*, Docket No. UE-061546, Order 08 ¶ 62 (June 21, 2007) (“ . . . ICNU recommends that the Commission approve a PCAM that is focused narrowly on variability of hydro-generation . . .”; *Wash. Utils. & Transp. Comm’n v. PacifiCorp*, Docket No. UE-061546, Direct Testimony of Randall J. Falkenberg, Exhibit No. RJF-1T at 69-72 (Feb. 16, 2007).

<sup>73</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 56.

<sup>74</sup> *In re PacifiCorp*, OPUC Docket No. UE 246, Exhibit PAC/2200, Duvall/2 (Sept. 5, 2012).

<sup>75</sup> *Id.*

1 **Q. Parties also claim that the Company’s proposed RRTM could allow it to**  
2 **surcharge customers for variations in wind generation even when the**  
3 **Company’s overall NPC were less than forecast.<sup>76</sup> How do you respond?**

4 A. While this concern seems mostly theoretical given the Company’s consistent under-  
5 recovery of NPC in Washington, the Company is willing to modify its RRTM to cap  
6 the potential customer charges to ensure that the Company recovers no more than its  
7 actual NPC in any particular year. In this way, the Company could never recover  
8 more than its actual NPC. This cap makes the RRTM more restrictive than Staff’s  
9 proposed PCAM, which would allow the Company to recover more than its actual  
10 NPC after application of the sharing and dead bands.

11 **LOW HYDRO DEFERRAL**

12 **Q. Please describe the Company’s deferred accounting request related to low hydro**  
13 **conditions.**

14 A. The Company filed an application with the Commission on January 17, 2014, seeking  
15 authorization to defer for later ratemaking treatment costs associated with significant  
16 variances in actual hydro generation and hydro generation in rates due to abnormal  
17 weather conditions and water availability.

18 **Q. Do the other parties support the Company’s low hydro deferral?**

19 A. No. Staff calculates the hydro generation variance for 2014 as within 2.9 percent of  
20 hydro generation included in rates and claims this is within an acceptable range;  
21 however an “acceptable range” is left undefined.<sup>77</sup> Public Counsel argues that it is  
22 not appropriate to defer a select portion of NPC variances between rate cases.<sup>78</sup> Boise

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<sup>76</sup> See e.g. Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 39.

1 rejects the low hydro deferral, arguing that hydro conditions are “about normal” and  
2 the deferral is one sided.<sup>79</sup>

3 **Q. How do you respond?**

4 A. Hydro resources provide customers with the benefit of a zero-net-power-cost  
5 generating resource. When actual hydro generation is less than the hydro generation  
6 in rates it must be replaced by either purchasing power or increased thermal  
7 generation. Due to abnormal hydro conditions beginning in late 2013 and continuing  
8 in 2014, the Company has been incurring replacement power costs caused by the  
9 variance in hydro generation. Without the deferral, the Company would absorb the  
10 costs resulting from unpredictable weather outside of the Company’s control.

11 **Q. How do you respond to Staff’s comment that “[the Company] is compensated for**  
12 **“abnormal” hydro variances in net power costs and needs no special accounting**  
13 **treatment”?**

14 A. Staff’s comment is misguided as it incorrectly accounts for the development of hydro  
15 generation levels in the Company’s pro forma NPC. For the purpose of setting rates,  
16 the Company uses a single-year of median-hydro generation levels. Other  
17 Washington utilities set rates based on the average costs in 40 or more historical  
18 water years, which reflects the costs and benefits of the variance in hydro generation  
19 in the historical data set. However, the Company’s hydro generation forecast, based  
20 on a median water year, does not account for any of the costs or benefits associated  
21 with year-to-year variability.

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<sup>77</sup> Testimony of David C. Gomez, Exhibit No. DCG-1CT at 16-18.

<sup>78</sup> Revised Testimony of Donna M. Ramas, Exhibit No. DMR-1CT at 42-45.

<sup>79</sup> Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 67-68.

1 **Q. Have you updated the costs of replacement power associated with low hydro**  
2 **conditions?**

3 A. Yes. Attached as Confidential Exhibit No. GND-8C is the Company's fifth  
4 supplement response to Public Counsel Data Request 2 in the low hydro deferral  
5 docket (Docket UE-140094). The response provides actual excess NPC associated  
6 with low hydro conditions through September 2014, as well as an updated projection  
7 through December 2014. Based on this updated data, hydro generation for all of 2014  
8 is approximately 7.6 percent lower than the amount in rates.<sup>80</sup> Accordingly, the  
9 Company requests amortization of approximately \$2.4 million in Washington-  
10 allocated excess NPC. The Company's deferral request is also discussed in the  
11 rebuttal testimony of Ms. Siores.

#### 12 **THERMAL OUTAGE MODELING**

13 **Q. What does Boise recommend regarding certain outages at Chehalis and Colstrip**  
14 **Unit 4?**

15 A. Boise claims that two outage events, one at Chehalis and one at Colstrip Unit 4, were  
16 the result of imprudent operations and recommends disallowance of the related costs.  
17 For Chehalis, Boise recommends removing the outage from the four-year historical  
18 average outage rate used to determine pro forma NPC. For Colstrip Unit 4, Boise  
19 recommends the Commission reject the Company's application for deferred  
20 accounting and recovery of related costs.

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<sup>80</sup> The 2.9 percent calculated by Mr. Gomez is based on actual hydro generation through August 2014 and excludes the first 17 days of January, consistent with the Company's deferred accounting application. Including actual hydro generation through September and an updated balance of year forecast increases the 2.9 percent to 5.3 percent.

1 **Q. How does the Company respond to the allegations that the outages were the**  
2 **result of imprudent operations?**

3 A. Boise's allegations are incorrect. In his rebuttal testimony, Mr. Dana M. Ralston  
4 provides evidence demonstrating the outages at Chehalis and Colstrip Unit 4 occurred  
5 despite prudent plant operation.

6 **Q. What are the implications for cost recovery if the Chehalis outage is removed**  
7 **from the average?**

8 A, The Company uses a four-year historical average outage rate at each plant to  
9 determine the plant availability during the pro forma period used to determine NPC in  
10 rates. If outage events such as those at Chehalis and Colstrip Unit 4 are not included  
11 in the historical average, the Company will have no way to recover the cost of such  
12 events without some kind of deferral mechanism, even when the outages are  
13 determined to be prudent.

14 **Q. How have you addressed this situation for the Colstrip outage?**

15 A. Due to the anticipated length of the Colstrip outage, the Company filed its request for  
16 deferred accounting treatment of the replacement power costs. In conjunction with  
17 deferred accounting treatment, the average outage rate used in the general rate case  
18 for Colstrip Unit 4 is set at a normalized, lower level that does not reflect the outage  
19 in question.

20 **Q. What about the Chehalis outage?**

21 A. In this case, if the Chehalis outage is removed from the average outage calculation,  
22 the Company will not recover the net power cost impact of the outage.



1 **Q. Has Staff previously agreed that deferred accounting was an appropriate option**  
2 **if prudent forced outages are normalized out of the forced outage rate?**

3 A. Yes. As I described in my direct testimony, in Docket UE-100749, the Commission  
4 approved an adjustment to limit the forced outage rate to eight percent for Colstrip  
5 Unit 4. In that case, the Company included a seven-month outage at the plant during  
6 2009 in the 48-month historical average, increasing the calculated outage rate used in  
7 GRID. The Commission determined that the extended outage should not be included  
8 in the historical average because the result was less predictive of what may occur in  
9 the future. In that case, Staff recognized that reducing the outage rate would limit  
10 cost recovery for the incident, and Staff supported the idea of using deferred  
11 accounting to achieve recovery.<sup>81</sup> Ms. Siores provides additional testimony on the  
12 Colstrip deferred accounting request in her rebuttal testimony.

13 **Q. If deferred accounting is not approved for the Colstrip Unit 4 outage, should the**  
14 **Company's forced outage rate be adjusted to include this outage?**

15 A. Yes. In the current filing, the 48-month historical outage rate for Colstrip Unit 4 is  
16 influenced by the extended forced outage in 2013; however, the Company limited the  
17 outage rate used for NPC to eight percent. If the Company's request for deferred  
18 accounting is rejected, the historical outage rate for Colstrip Unit 4 should be  
19 increased to reflect actual plant operations.

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<sup>81</sup> *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket No. UE-100749, Buckley, Transcript 584:3-10 (Jan. 26, 2011) (“For the case of PacifiCorp, which does not have any kind of power cost mechanism, then I’m proposing it could be done through an accounting petition or some other method, which is really very similar if not the same as what we’ve already done with—I believe it was the kind of anomalous hydro generation outages back during the energy crisis there was some deferred power costs that the Company filed for recovery of.”).

1 **ACCEPTED ADJUSTMENT**

2 **Q. Does the Company accept Boise's adjustment related to network integration**  
3 **transmission service, or NITS, from BPA?**

4 A. Yes, in part. The Company accepts in concept Boise's adjustment to reduce wheeling  
5 expenses related to BPA NITS. But Boise's proposed calculations to determine BPA  
6 NITS expense for the forecast period are flawed and overstate the required  
7 adjustment.

8 **Q. What are the BPA NITS wheeling expenses?**

9 A. Some of the Company's west control area retail loads are served using BPA's  
10 transmission system, rather than exclusively using Company-owned transmission  
11 assets. BPA charges for NITS based on a customer's load during the hour of BPA's  
12 transmission system peak in each month. The rates charged by BPA for this service  
13 were last updated in October 2013 as part of BPA's most recent rate case.

14 **Q. How did the Company calculate BPA NITS expense in its initial filing?**

15 A. The Company applied the current BPA rates to its forecasted load at the time of its  
16 non-coincident peak during the pro forma period for each load pocket served with  
17 BPA NITS.

18 **Q. Please describe Boise's proposed adjustment related to BPA NITS expense.**

19 A. Boise's adjustment calculates the Company's BPA NITS expense based on the  
20 average of the Company's forecasted BPA NITS loads in four hours per month. The  
21 hours selected match the day of the month and the hour from the actual BPA  
22 transmission system peak from each of the last four years.

1 **Q. Do you agree with Boise's proposed method to approximate BPA NITS expense?**

2 A. No. Boise's proposed adjustment is an overly complicated attempt to forecast the  
3 time of BPA transmission system peak during the rate-effective period. There are  
4 two primary flaws in Boise's proposed method. First, under Boise's methodology,  
5 23 percent of the BPA system peaks in the forecast period occur on Sunday. In the  
6 last 48 months, the BPA system peak only occurred on a Sunday once, or about two  
7 percent of the time.

8 The second flaw with Boise's methodology is that it ignores weather, which is  
9 the biggest driver of peak loads. The Company's pro forma NPC is based on normal  
10 weather, with a shape representing the range of expected temperatures in each month.  
11 The coldest days in the winter months and the hottest days in the summer months  
12 have the highest loads. The BPA system and the Company's BPA NITS loads are  
13 both located in the Pacific Northwest and experience similar weather. This weather  
14 varies from year-to-year, thus the day of the peak does not provide insight into the  
15 timing of the BPA system peak in other periods. Because the day of the month has  
16 little to do with the weather, Boise's method is effectively basing the costs on loads  
17 from random days in the forecast period.

18 **Q. Is the impact of Boise's adjustment reasonable?**

19 A. No. Boise's proposed BPA NITS wheeling expense forecast is lower than the 2013  
20 actual levels. This result is particularly unreasonable considering that in October  
21 2013 BPA implemented a rate increase, raising the NITS rates by 9.3 percent.

1 **Q. Please describe the adjustment the Company incorporated in its rebuttal NPC**  
2 **update.**

3 A. The historical BPA NITS wheeling expenses for 2013 reflect nine months of BPA's  
4 old rates in January through September, and three months of the current rates which  
5 took effect in October 2013. The Company's rebuttal update adjusts the historical  
6 expenses for January through September to account for the change from BPA's old  
7 rates to its current rates and includes expenses for October through December at the  
8 actual levels.

9 **Q. Are there any other factors that could contribute to higher BPA NITS expense in**  
10 **the pro forma period?**

11 A. Yes. BPA's current rates are in effect through September 2015, six months into the  
12 pro forma period in this case. BPA has projected that NITS rates may increase by  
13 9.7 percent in October 2015.<sup>82</sup> Because the Company's request in this case does not  
14 include any future BPA rate increases, there is a significant potential for higher BPA  
15 NITS expense.

16 **Q. How should the BPA NITS expense be calculated for the pro forma period?**

17 A. Adjusting the historical expense for the BPA rate change which occurred on  
18 October 1, 2013, is straightforward and reasonably captures the actual historical  
19 relationship between the Company's BPA NITS loads and BPA's transmission  
20 system peak. This adjustment results in a reduction to west control area NPC of  
21 \$0.8 million.

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<sup>82</sup> BPA Presentation: *Building the Framework for the 2014 Integrated Program Review*. Available online at: [www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2014IPRDocuments/Building%20the%20Framework%20for%20the%20IPR%201.8.2014.pdf](http://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2014IPRDocuments/Building%20the%20Framework%20for%20the%20IPR%201.8.2014.pdf), accessed November 10, 2014.

1 **Q. Does this conclude your rebuttal testimony?**

2 **A. Yes.**