BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, Request for a General Rate Revision	**UE 374**

Sierra Club Hearing Reference Materials

Cross Examination of Mr. Rick Link

September 2, 2020

Sierra Club Reference Materials: Link Cross Examination

Exhibit No.	Description	Pages Referenced	Confidential (Yes/No)
PAC/708	Confidential Natural Gas Price Assumptions	Entire document	Yes
PAC/709	Confidential SO Model Results for Gas Price Scenarios	Entire document	Yes
Sierra Club/102	Public Selected Data Responses	Fisher/7-9, 12 (SC 1.4 and 1.6)	No
PAC/700	Direct Testimony of Rick Link	Link/93-110	Yes
PAC/2300	Reply Testimony of Rick Link	Link/7-33, 40-46	Yes
PAC/3800	Surrebuttal Testimony of Rick Link	Link/4-15	Yes
Sierra Club/100	Opening Testimony of Jeremy Fisher	Fisher/47-49	Yes
Sierra Club/714	Confidential Link Workpaper "Link Figures 11, 12, 14.xlsx"	N/A	Yes
Sierra Club/715	Attachment to PacifiCorp Response to Sierra Club Data Request 1.6	N/A	No
Sierra Club/716	PacifiCorp Response to Sierra Club Data Request 12.5	Entire document	No
Sierra Club/717	Confidential PacifiCorp Response to Sierra Club Data Request 7.1	Entire document	Yes
Sierra Club/718	Confidential Attachment to Sierra Club 7.1-1	N/A	Yes
Sierra Club/719	PacifiCorp Response to Sierra Club Data Request 7.2	Entire document	No
Sierra Club/720	Confidential Attachment to Sierra Club 7.2-2: "PIRA_REDACTED_Nominal$_10.10.13 PROPRIETARY CONF.xlsx"	N/A	Yes

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Docket No. UE 374
Exhibit Sierra Club/102
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 102

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Public Discovery Responses

UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.4

Sierra Club Data Request 1.4

Refer to the Direct Testimony of Mr. Rick Link, page 107 at 9-14. "Based upon the breakeven relationship described above, PacifiCorp determined that the SCR emission control systems remained the most economical environmental compliance option for Jim Bridger Units 3 and 4, benefiting customers by approximately $130 million more than the gas-conversion alternative… When evaluating natural-gas prices before issuing the FNTP…"

(a) Provide the work papers demonstrating the $130 million benefit described above.

(b) Provide contemporaneous documentation, including correspondence, emails, memoranda, presentations, and the like demonstrating that the Company had assessed, and affirmed a ratepayer benefit of $130 million prior to signing the FNTP. If an electronic document is produced, provide evidence of the time- and date-stamp for that document.

(c) Identify the individual or individuals who produced that documentation, and identify the recipients of that documentation.

(d) Confirm or deny: the Company did not re-run System Optimizer to assess the Jim Bridger SCR installation decision after the determination of the $183 million benefit.

Response to Sierra Club Data Request 1.4

(a) Please refer to Confidential Attachment Sierra Club 1.4-1. Tab "Trend Data CONF," cell E37 reports the $130 million selective catalytic reduction (SCR) benefit. Please also refer to the direct testimony of company witness, Rick T. Link, specifically Confidential Exhibit PAC/710, Link/1 (PacifiCorp's regression analysis for changes in natural gas prices reflected in the official forward price curve (OFPC)).

(b) PacifiCorp objects to this data request to the extent it implies that contemporaneous documentation is a pre-requisite to establishing the prudence of a utility's actions. Prudence determinations are based on an objective standard of reasonableness. If the record demonstrates that a challenged business decision was objectively reasonable considering established historical facts and circumstances, the utility's decision will be upheld as prudent without contemporaneous documentation of the utility's actual subjective decision making process. *In the Matter of the Application of PacifiCorp for an Accounting Order Regarding Excess Net Power Costs*, Docket UM 995, Order 02-469 (July 11, 2002).

Notwithstanding this objection, PacifiCorp responds as follows:

PacifiCorp made its decision to proceed with the Jim Bridger SCR investment in late May 2013. This decision was supported by voluminous evidence, including PacifiCorp's economic analysis included in Confidential Volume III of PacifiCorp's 2013 Integrated Resource Plan (IRP) filed in April 2013, detailed cost estimates, fully litigated state regulatory approvals received in May 2013, and environmental permitting and reviews. This evidence is summarized in PacifiCorp's appropriation approval request (APR), dated April 2013, and APR update, dated May 22, 2013. Please refer to Confidential Attachment Sierra Club 1.4-2 and Confidential Attachment Sierra Club 1.1-1 (file "LNTP Jim Bridger Units 3 and 4 SCR Systems Approval Request Memo_20130522 CONF"), respectively for these documents.

To minimize the risks of the Jim Bridger SCRs for customers, PacifiCorp negotiated an innovative engineer, procure, construct (EPC) contract that allowed the company to delay significant investment in the Jim Bridger SCRs to the last possible date, December 1, 2013, while still ensuring that the company could cost-effectively meet its compliance deadlines. The EPC contract allowed the company to withdraw if material changes before December 1, 2013 impacted the economics or the company's ability to implement the SCR projects.

Before issuing the final notice to proceed (FNTP) under the EPC contract, PacifiCorp reviewed key decision factors for material, adverse changes, including the natural gas prices reflected in the then most recent OFPC dated September 2013. PacifiCorp's regression analysis included in Mr. Link's direct testimony, specifically Exhibit PAC/710, Link/1 showed an updated present value of revenue requirements differential (PVRR(d)) of $130 million supporting the SCR decision based on that OFPC. Additionally, PacifiCorp reviewed 10-year budget projections based on the October 2013 mine plan showing that Jim Bridger coal costs were not expected to increase significantly, and a significant cost reduction the company negotiated in the EPC contract. The company also verified that none of its third-party forecast providers had projected increases in carbon costs in response to President Obama's 2013 Presidential Memorandum on carbon emissions.

Company witness, Chad A. Teply personally performed the review of these factors, in regular consultation with Mr. Link and members of PacifiCorp's fuels group, and has testified to this review in other state proceedings, including most recently in PacifiCorp's California general rate case, Application 18-04-002. In that proceeding, the California Public Utilities

Commission concluded that the Jim Bridger SCR investment was prudent. Please refer to Decision 20-02-025.

On December 5, 2013, PacifiCorp summarized various considerations supporting the FNTP in a memorandum, also provided in Confidential Attachment Sierra Club 1.4-3.

(c) The documentation was produced at the direction of company witness Rick T. Link. The recipients were two regulatory filings: (1) Application for a Certificate of Public Convenience and Necessity filed with the Wyoming Public Service Commission on August 7, 2012 (Docket 20000-418-EA-12), and (2) Voluntary Request for Approval of Resource Decision filed with the Public Service Commission of Utah on August 24, 2012 (Docket 12-035-92). Please also refer to the company's response to subpart (b) above.

(d) The company confirms that it relied upon the System Optimizer model (SO model) results from February 2013, which were updated for the 2013 IRP, to develop its regression analyses set forth in Mr. Link's direct testimony, specifically Confidential Exhibit PAC/710, Link/1, and Confidential Exhibit PAC/711, Link/1. The modeling results from February 2013 included a range of different natural gas and carbon price scenarios which allowed the results to remain current as these inputs fluctuated in 2013 and demonstrated that it would take a significant change of circumstances for the SCR benefits to dissipate. In addition, the regression graphs for natural gas and carbon prices are a close representation of what the SO model would produce. These graphs allowed the company to rapidly re-assesses how a significant assumption like natural gas prices affected the relative economics of SCRs versus natural gas conversion. In advance of issuing the FNTP, the company relied upon these graphs in confirming that the company's May 2013 decision to proceed with the SCR investment remained the most beneficial option for customers.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.6

Sierra Club Data Request 1.6

Refer to the Direct Testimony of Mr. Rick Link, page 94 at 3 with reference to the September 2012 OFPC, page 107 at 7 with reference to the September 2013 OFPC, and page 87 at 2-4 with respect to the completion timeline of the SCR projects.

(a) Confirm or deny: at the time of the September 2013 OFPC and at the time of the FNTP for the SCR projects, Mr. Link was the PacifiCorp employee responsible for the production of gas price forecasts relied upon by the Company. If denied, identify the employee at PacifiCorp ultimately responsible for the production of gas price forecasts relied upon by the Company.

(b) Confirm or deny: at the time of the September 2013 OFPC and at the time of the FNTP for the SCR projects, Mr. Link was the PacifiCorp employee responsible for the production of OFPC. If denied, identify the employee at PacifiCorp ultimately responsible for the production of OFPC relied upon by the Company.

(c) Provide each OFPC produced by PacifiCorp between December 2011 and December 2016, inclusive.

Response to Sierra Club Data Request 1.6

(a) Confirmed.

(b) Confirmed.

(c) Please refer to Attachment Sierra Club 1.6 which provides PacifiCorp's official forward price curves produced between December 2011 and December 2016.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 374

SIERRA CLUB EXHIBIT 716

Cross-Examination Exhibit

UE 374/PacifiCorp
August 31, 2020
Sierra Club Data Request 12.5

Sierra Club Data Request 12.5

Refer to PAC/3800 at Link/7:17-Link/8:1 and PAC/2300 at Link/23:13-18.

(a) Provide any records in the Company's possession on market forwards, for as far forward as in the Company's possession, obtained by or produced for the Company between September 1, 2013 through December 1, 2013. For clarity, this requests market forward records as produced or provided to the Company at any time from September 1, 2013 through December 1, 2013 for the forward period extending December 2013 through the next 84 months.

Response to Sierra Club Data Request 12.5

(a) The Company objects to this request as overly burdensome and onerous that would not lead to a meaningful outcome. Notwithstanding the foregoing objections, the Company responds as follows:

The Company has provided all the available information in its possession for September 2013 and December 2013 related to natural gas and electricity prices quarterly forecasts with its responses to Sierra Club Data Request 7.1, Sierra Club Data Request 12.3, and Sierra Club Data Request 12.4.

PUBLIC UTILITY COMMISSION OF OREGON

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SIERRA CLUB EXHIBIT 719

Cross-Examination Exhibit

UE 374/PacifiCorp
July 6, 2020
Sierra Club Data Request 7.2

Sierra Club Data Request 7.2

Refer to the Reply Testimony of Mr. Rick Link, PAC/2300 at Link/25:3-12.

(a) For each of the three different third-party experts consulted for long-term price forecasts, provide Mr. Link's calculated nominal levelized price of Opal gas prices (in $/MMBtu) for the most recent forecast preceding the September 2013 OFPC.

(b) For each of the three different third-party experts consulted for long-term price forecasts, provide Mr. Link's calculated nominal levelized price of Opal gas prices (in $/MMBtu) for the first forecast post-dating the September 2013 OFPC.

Response to Sierra Club Data Request 7.2

(a) Please refer to Confidential Attachment Sierra Club 7.2-1 which provides the nominal levelized price of Opal gas (dollars per million British thermal units ($/MMBtu)) as calculated from the published forecasts of three expert third-party subscription services. The provided long-term price forecasts were the most then-current available prior to PacifiCorp's publication of the September 2013 official forward price curve (OFPC). Note: the confidential attachment referenced above provides the third-party information that is in the Company's possession. The provided third-party information is proprietary and is provided subject to the terms and conditions of the protective order/confidentiality agreement in this proceeding.

(b) Please refer to Confidential Attachment Sierra Club 7.2-2 which provides the nominal levelized price of Opal gas ($/MMBtu) as calculated from the published forecasts of three expert third-party subscription services. The provided long-term price forecasts were the most then-current available following PacifiCorp's publication of the September 2013 OFPC. Note: the confidential attachment referenced above provides the third-party information that is in the Company's possession. The provided third-party information is proprietary and is subject to the terms and conditions of the protective order/confidentiality agreement in this proceeding.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, Request for a General Rate Revision	**UE 374**

Sierra Club Hearing Reference Materials

Cross Examination of Mr. Dana Ralston

September 2, 2020

UE 374

Sierra Club Reference Materials: Ralston Cross Examination

Exhibit No.	Description	Pages Referenced	Confidential (Yes/No)
Sierra Club/109	Redacted Supplemental Rebuttal Testimony of Cindy A. Crane in UE-152253 (Wash. U.T.C),	Entire document	No
PAC/2603	Confidential Corrected Coal Cost Comparison Between January 2013 Long-Term Fueling Plan and October 2013 Mine Plan	Entire document	Yes
PAC/2608	Highly Confidential Excerpt from Hayden Participation Agreement	Entire document	Yes (HC)
PAC 2600	Rebuttal Testimony of Dana Ralston	Ralston/9-14	Yes
PAC/4100	Surrebuttal Testimony of Dana Ralston	Ralston/5-10	Yes
Sierra Club/123	Confidential Hayden SCR Recommendation Memo	Entire document	Yes
Sierra Club/701	PacifiCorp Response to Sierra Club Data Request 11.1	Entire document	No
Sierra Club/702	PacifiCorp Response to Sierra Club Data Request 11.2	Entire document	No
Sierra Club/703	Confidential PacifiCorp Response to Sierra Club Data Request 11.3	Entire document	Yes
Sierra Club/704	PacifiCorp Response to Sierra Club Data Request 11.4	Entire document	No
Sierra Club/705	PacifiCorp Response to Sierra Club Data Request 11.5	Entire document	No
Sierra Club/706	Confidential PacifiCorp Response to Sierra Club Data Request 11.6	Entire document	Yes
Sierra Club/707	Confidential PacifiCorp Response to Sierra Club Data Request 11.7	Entire document	Yes

Exhibit No.	Description	Pages Referenced	Confidential (Yes/No)
Sierra Club/708	Confidential Attachment to Sierra Club 9.1, "BCC Production-Operating Cost Schedules (4-unit Coal Operation).xlsx", tab “OPEX”	tab “OPEX	Yes
Sierra Club/709	Confidential Attachment to Sierra Club 9.1, "BRIDGER (2015 IRP).xlsx"	N/A	Yes
Sierra Club/710	Confidential Attachment to Sierra Club 9.1, "Bridger Summary Analysis.xlsx"	N/A	Yes
Sierra Club/711	Confidential Attachment to Sierra Club 1.8, "BRIDGER.xlsx"	N/A	Yes
Sierra Club/712	Confidential Attachment to Sierra Club 12.1-1, "BRIDGER.xlsx"	NA	Yes
Sierra Club/713	Confidential Ralston Workpaper "CONF Exhibit_PAC_2603_CONF and WPs.xlsx"	N/A	Yes

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Exhibit Sierra Club/109
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

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SIERRA CLUB EXHIBIT 109

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Redacted Supplemental Rebuttal Testimony of Cindy A. Crane

Exhibit No. CAC-1CT
Docket UE-152253
Witness: Cindy A. Crane

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET UE-152253

PACIFIC POWER & LIGHT COMPANY

**REDACTED SUPPLEMENTAL REBUTTAL TESTIMONY OF
CINDY A. CRANE**

May 2016

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ATTACHED EXHIBITS

Confidential Exhibit No. CAC-2C—Corrected Coal Cost Comparison between January 2013 Long-Term Fueling Plan and October 2013 Mine Plan

Confidential Exhibit No. CAC-3C—Analysis of Hypothetical Jim Bridger Two-Unit Scenario

Exhibit No. CAC-4—Pacific Power's Response to Sierra Club Data Request 1.11

Q. Please state your name, business address, and present position.

A. My name is Cindy A. Crane. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. I am the President and Chief Executive Officer of Rocky Mountain Power, a division of PacifiCorp.

Q. Have you previously testified in this proceeding on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. No, but I am adopting the pre-filed rebuttal testimony and exhibits of Mr. Dana Ralston, which have been identified as Exhibit Nos. DR-1CT, 2C, 3C, and 4C.

QUALIFICATIONS

Q. Briefly describe your professional experience.

A. I joined PacifiCorp in 1990. Since then I have served as Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis, Vice President of Strategy and Division Services, and Vice President of Interwest Mining Company and Fuel Resources. My responsibilities in these positions included the management and development of PacifiCorp's 10-year business plan, directing operations of the Energy West Mining and Bridger Coal companies, and coal supply acquisition and fuel management for PacifiCorp's coal-fired generating plants. In October 2014, I was appointed to my present position as President and Chief Executive Officer of Rocky Mountain Power.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before public utility commissions in all states in which PacifiCorp serves customers, including Washington.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your supplemental rebuttal testimony?

A. My testimony responds to the supplemental testimony of Mr. Jeremy B. Twitchell on behalf of Staff of the Washington Utilities and Transportation Commission (Commission) related to the prudence of the Company's decision to install selective catalytic reduction systems (SCRs) on Units 3 and 4 of the Jim Bridger generating plant (Jim Bridger Units 3 and 4). In particular, I respond to Staff's analysis of the coal costs Pacific Power used in its present value revenue requirement differential calculations (PVRR(d)) supporting the decision to install SCRs.

Q. Please summarize your testimony.

A. Pacific Power's decision to install SCRs at Jim Bridger Units 3 and 4 was prudent, and the Company's analysis supporting the decision was based on the best available information at the time the decision was made. Staff accuses the Company of failing to consider increases in coal costs and decreases in natural gas prices when it issued the full notice to proceed (FNTP) on December 1, 2013. Staff bases these accusations on an alleged lack of evidence that these changes were considered, and relies on an analysis of Bridger Coal Company (BCC) coal costs prepared by the Company in fall 2013 as part of its annual budgeting process (the October 2013 mine plan) and selective application of third-party natural gas price forecasts. Staff's accusations are unfounded and untrue.

Mr. Chad A. Teply addresses Staff's assertions that the Company did not consider these changes in December 2013 before issuing the FNTP, and Mr. Rick T. Link addresses the natural gas price forecasts. In this testimony, I address Staff's assertions about estimated coal costs in fall 2013. Although certain costs related to BCC increased in the October 2013 mine plan, other costs decreased, including decreases in capital expenditures and third-party coal costs. The changes in the October 2013 mine plan were not material and did not warrant an update to the Company's long-term fueling plan (what has been called the January 2013 mine plan, but is referred to in the Company's supplemental rebuttal testimony as the January 2013 long-term fueling plan to clarify the intended purposes of the two different types of plans) or its SCR analysis.

OCTOBER 2013 MINE PLAN

Q. Please describe the Company's October 2013 mine plan.

A. As discussed in Mr. Ralston's rebuttal testimony, the October 2013 mine plan was developed by the Company as part of its annual budgeting process.[1] The plan was prepared to forecast BCC coal costs for a 10-year budget horizon. Although the October 2013 mine plan includes forecasts beyond this 10-year horizon, this information is used only to develop reclamation funding inputs for the 10-year budget horizon. In contrast, the Company prepares long-term fueling plans, such as the January 2013 long-term fueling plan, for use in the integrated resource planning process and in analyses of decisions with long-term impacts to the Company and its customers, such as the decision to install SCRs at Jim Bridger Units 3 and 4. Therefore, the nature of the data provided in the two types of plans is different, and different analytical rigor is applied in developing the long-term data included in the plans.

[1] Ralston, Exh. No. DR-1CT 3:8-4:10.

Q. Is the October 2013 mine plan directly comparable to the January 2013 long-term fueling plan?

A. No. As Mr. Ralston previously testified, the plans are not comparable given the major differences in their purpose, scope, and planning horizons. The Company never relied on the October 2013 mine plan as a long-term fueling forecast for the Jim Bridger plant.

Q. Did the BCC coal costs included in the October 2013 Mine Plan increase by [redacted] over the BCC coal costs included in the January 2013 long-term fueling plan, as Staff testified?[2]

A. No. Because the January 2013 and October 2013 plans are not directly comparable, Staff needed to make several assumptions in conducting its analysis. When errors in these assumptions are corrected, the results show that overall coal costs for the Jim Bridger plant increased by only [redacted] during the 10-year budget horizon covered by the October 2013 mine plan. This amount is consistent with the [redacted] increase reflected in the Company's long-term fueling plan for the Jim Bridger plant used for the 2015 Integrated Resource Plan (IRP) for the 2016-2030 period.[3] If the Company had updated costs by this percentage increase in both the two-unit operating scenario (the natural gas conversion alternative) and four-unit operating scenario (the SCR alternative), the SCR benefits would have decreased by approximately [redacted] over the 10-year budget period, as set forth in Exhibit

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[2] Twitchell, Exh. No. JBT-28HCT 18:12-15.
[3] Ralston, Exh. No. DR-1CT 7:16, Exh. No. DR-4C. The long-term fueling costs used in the 2015 IRP were based on the Company's July 22, 2014 BCC mine plan. The Company originally produced a BCC mine plan on July 9, 2014, that it used in its 10-year budget. This plan was updated with only a few changes in the July 22, 2014 mine plan. The long-term fueling plan was finalized in November 2014 after the Company had updated third-party coal costs.

No. CAC-2C. This is a conservative assumption because, as discussed below, the Company's analysis shows that projected cost increases in a two-unit scenario under the October 2013 mine plan would have offset all cost increases in the four-unit scenario.

Q. Before filing its initial or supplemental testimony, was Staff aware that the October 2013 Mine Plan was not directly comparable to the January 2013 long-term fueling plan?

A. Yes. In Mr. Twitchell's initial testimony, he explained that he had reviewed the record from the Company's 2014 Utah rate case to determine how the SCR investments were treated.[4] My testimony in that case explained the differences between the October 2013 mine plan and the January 2013 long-term fueling plan and made clear that they are not directly comparable.[5] Mr. Twitchell's review of the record from the 2014 Utah rate case should have alerted him to the material differences in these two plans. Moreover, Mr. Ralston clearly explained in his rebuttal testimony that these two plans are not directly comparable for the same reasons discussed here.[6]

Q. Please describe the first incorrect assumption made in Staff's new analysis.

A. Staff mistakenly assumes that the long-term data in the October 2013 mine plan is comparable to the long-term data in the January 2013 long-term fueling plan and uses some of this longer-term data from the October 2013 mine plan (data for the period

[4] Twitchell, Exh. No. JBT-1T 62:1-4. Sierra Club also included a copy of my Utah rebuttal testimony as an exhibit to its testimony in this case. Fisher, Exh. No. JIF-8. The Company's 2014 Utah rate case was docket No. 13-035-184.
[5] *See e.g.* Exh. No. JIF-8 5:72-81.
[6] Ralston, Exh. No. DR-1CT 3:8-23.

2023 through 2030).[7] As I explain above, the long-term cost and revenue assumptions included in the October 2013 mine plan were not developed with the same analytical rigor that the Company uses to develop its long-term fueling plans because this data is used solely to determine appropriate contributions to the reclamation sinking fund during the 10-year budget horizon. This is why, as Staff noted, in the October 2013 mine plan the longer-term capital cost data was kept in a different file than the capital cost data for the 10-year budget horizon.[8]

Q. Please describe the second erroneous assumption in Staff's analysis.

A. Staff's analysis includes a modeling error in BCC's "Mine and Equipment Maintenance" cost component in 2028 that inflates coal costs by [redacted] (Company portion, [redacted]). On a net-present-value basis, correcting this error reduces Staff's calculated coal cost increase by approximately [redacted].

Q. What is the impact of correcting the analysis to account for only the 10-year budget horizon reflected in the October 2013 mine plan and correcting Staff's modeling error?

A. The overall increase in coal costs is only [redacted]. Notably, this increase is consistent with the overall increase between the January 2013 and 2015 IRP long-term fueling plans for the Jim Bridger plant, as I note above. The fact that the long-term cost projections in the 2015 IRP are consistent with the 10-year budget but inconsistent with Staff's 2016 to 2030 analysis highlights the underlying problems in Staff's approach.

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[7] *See e.g.* Twitchell, Exh. No. JBT-28HCT 18:7-9.
[8] Twitchell, Exh. No. JBT-28HCT 17 n. 21.

Q. Are there any other indicators that Staff's analysis was flawed?

A. Yes. The flaws in Staff's revised analysis should have been apparent simply by examining the overall results. In response testimony, Staff claimed that BCC coal costs increased by [redacted], which resulted in a downward adjustment to the SCR benefits of [redacted].[9] Now, Staff claims that coal costs increased by only [redacted], yet the downward SCR adjustment increased to [redacted].[10]

Q. Staff contends that the Company's continued reliance on the January 2013 long-term fueling plan even after the October 2013 mine plan was developed was unreasonable.[11] How do you respond?

A. I disagree. During the budgeting process in fall 2013, the Company recognized that increases in BCC cash costs would be substantially offset by reduced BCC capital spending and third-party fuel costs. Nothing in the October 2013 mine plan signaled that the January 2013 long-term fueling plan was obsolete.

Q. Staff bolsters its long-term analysis by pointing to coal cost increases reported in the Company's 2014 Washington rate case.[12] Is Staff's reliance on rate case coal costs appropriate here?

A. No. Staff claims that if the October 2013 mine plan "created cost increases that were sufficiently known and measurable to support a rate increase, then those costs increases were sufficiently known and measurable to be included in the Company's planning." But as Staff acknowledges, the coal costs included in the Company's rate

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[9] Twitchell, Exh. No. JBT-1T 34:12-14; 9, Figure 1.
[10] Twitchell, Exh. No. JBT-28HCT 18:12-15; 19:20-21.
[11] Twitchell, Exh. No. JBT-28HCT 6:12-19.
[12] Twitchell, Exh. No. JBT-28HCT 7:8-12; 8:1-14; 10:17 – 11:20. The Company's 2014 Washington rate case was Docket UE-140762.

case filings reflect costs expected during the rate year.[13] The analysis used to develop test-period coal costs for a general rate case is fundamentally different from the analysis required to develop long-term fuel plans for a generating plant. Because the October 2013 mine plan updated BCC coal costs for the 10-year budget horizon (a relatively short-term period), the Company reasonably relied on the October 2013 mine plan to establish short-term rates. The fact that the mine plan was used to determine short-term costs does not mean that it is appropriate as a long-term forecast or as a comprehensive life-of-plant fueling plan for the Jim Bridger plant.

THIRD-PARTY FUEL COSTS

Q. **Staff acknowledges that the October 2013 Mine Plan did not update third-party coal costs.[14] Staff therefore relied on the third-party coal increases from the 2014 Washington rate case to forecast the change in third-party coal costs over the 2016 to 2030 study period.[15] Is this a valid way to forecast third-party coal costs?**

A. No. Staff's reliance on the 2014 Washington rate case produces two fundamental errors in its analysis of third-party coal costs. First, Staff unreasonably assumes an [redacted] annual cost increase for third-party coal. Second, Staff unreasonably assumes that the production ratio between BCC and third-party suppliers reflected in the Company's direct filing in its 2014 Washington rate case will remain constant through 2030. Both of these assumptions are incorrect.

[13] Twitchell, Exh. No. JBT-28HCT 11: 16-17.
[14] Twitchell, Exh. No. JBT-28HCT 10:5-9.
[15] Twitchell, Exh. No. JBT-28HCT 18:17 – 19: 8.

Q. How did Staff calculate its assumed increase for third-party coal costs?

A. Staff compared the costs of Black Butte coal in the Company's 2013 Washington rate case[16] to the costs of Black Butte coal in the Company's 2014 Washington rate case. Because costs increased by [redacted] between the 2013 and 2014 cases, Staff assumed that costs would continue to increase at [redacted] annually until 2030.[17]

Q. What is wrong with this assumption?

A. First, there were 15 months between the 2013 and 2014 net power cost test years. Therefore, the annual change is only [redacted], not [redacted]. Second, it is unreasonable to assume that third-party coal costs would increase at the same percentage annually through 2030 based on consideration of changes over only one 15-month period. The third-party cost increase between the 2013 and 2014 case represented a price change between two test periods based on contract terms that were expiring in 2015. There is absolutely no basis to assume that the increases in those cases reflect long-term expectations.

Q. How would you correct Staff's assumed third-party cost increase?

A. Based on what the Company knew in fall 2013, during the 10-year budget horizon third-party coal costs were expected to increase by roughly [redacted] annually. When factored into the overall plant fueling costs, third-party costs inclusive of coal inventory changes known in fall 2013 actually *decrease* by [redacted] relative to the third-party costs assumed in the SCR analysis. This decrease further offsets the modest increase in BCC costs reported in the October 2013 mine plan's 10-year budget horizon.

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[16] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043.
[17] Twitchell, Exh. No. JBT-28HCT 18:18-22.

Q. Are there any other deficiencies in Staff's analysis?

A. Yes. The Company's direct testimony in the 2014 Washington rate case was filed in May 2014, well after the period of time that Staff concedes is relevant to the prudence determination in this case. Staff claims that it is improper to reference the long-term fueling plan used in the 2015 IRP to validate the absence of major cost increases in the October 2013 mine plan. But Staff attempts to do the same thing by referencing Company testimony filed in May 2014. The testimony on which Staff relies, however, is irrelevant to the long-term coal cost increases at issue in this case.

Q. What is the second error in Staff's analysis?

A. Staff incorrectly assumes that the ratio between BCC and third-party coal reflected in a single year is indicative of the ratio from 2016 through 2030.[18]

Q. How did Staff determine the amount of coal provided by BCC and third-parties from 2016 through 2030?

A. To determine the ratio between BCC and third-party coal over a 17-year period, Staff relies on testimony from the Company's 2014 Washington rate case. In that case, the Company's direct testimony projected that BCC would provide roughly 85 percent of the plant's total coal, with third-party mines providing the remaining 15 percent. The Company's projection in the 2014 rate case, however, was based on expected coal deliveries *during a single year*—April 2015 through March 2016. Staff is incorrect to assume that BCC would provide 85 percent of the plant's total coal until 2030 based on a single year of data.

[18] Twitchell, Exh. No. JBT-28HCT 18:17 – 19:8.

The flaw in Staff's assumption is evident from the record in the 2014 rate case. By the time the Company filed its rebuttal testimony in that case, the proportion of BCC coal decreased to approximately 70 percent of the plant's total coal requirement.[19] This fact undermines Staff's claim that the October 2013 mine plan increased the Company's exposure to market risk because of greater reliance on third-party coal.[20]

TWO-UNIT SCENARIO

Q. Staff contends that if the Company had performed a two-unit scenario analysis in October 2013 it would have shown that coal costs in a two-unit scenario would have decreased, making gas conversion even more attractive.[21] Is Staff's conclusion sound?

A. No. Staff's analysis again relies on incorrect assumptions. First, Staff claims that the surface mine is subject to economies of scale, while implying that the underground mine is not.[22] On the contrary, both the surface and underground mine are subject to economies of scale—as production decreases in either operation the per-unit cost increases. Under a two-unit scenario, production would decrease.

Q. Does Staff's analysis include any other incorrect assumptions?

A. Yes. Staff reasons that under a two-unit scenario based on the October 2013 Mine Plan, the surface mine would continue to operate, which would avoid accelerated reclamation and result in lower costs relative to the two-unit scenario based on the

[19] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-140762, Exh. No. CAC-1CT 6:13-16.
[20] Twitchell, Exh. No. JBT-28HCT 12:10-18.
[21] Twitchell, Exh. No. JBT-28HCT 24:10-13.
[22] Twitchell, Exh. No. JBT-28HCT 23:19 – 24:13.

January 2013 long-term fueling plan.[23] Additionally, Staff states that availability of underground coal through 2023 in the October 2013 mine plan would also lower costs.[24] Relying on these assumptions, Staff concludes that a two-unit scenario based on the October 2013 mine plan would have lower costs than the January 2013 two-unit scenario.

Q. If the Company had developed a two-unit scenario based on the October 2013 Mine Plan, would the costs be less than the January 2013 two-unit scenario?

A. No. Both the January 2013 two-unit scenario and the October 2013 mine plan consider varying levels of underground coal production through 2023. The primary difference between the January 2013 two-unit scenario and a two-unit scenario based on the October 2013 mine plan is that surface mine closure occurs in 2018 in the January 2013 two-unit scenario and the surface mine continues to operate in the October 2013 mine plan.

To quantify the impact of this change using information available in fall 2013, the Company compared BCC surface mine cash costs, BCC surface mine capital costs expressed on a revenue requirement basis, and external coal prices to costs in the January 2013 two-unit scenario. Based on this analysis, the Company estimates that two-unit scenario coal costs would have increased by approximately [redacted] during [redacted] based on changes in the October 2013 mine plan. This is primarily due to higher costs at the surface mine. The cost increases in the two-unit scenario would have entirely offset the cost increases in the four-unit scenario in the Company's PVRR(d) analysis—making the SCR investment become more favorable

[23] Twitchell, Exh. No. JBT-28HCT 23:10-18.
[24] Twitchell, Exh. No. JBT-28HCT 24:8-10.

based on the October 2013 Mine Plan. My analysis is shown in Exhibit No. CAC-3C.

Q. How does this analysis relate to the Company's previous testimony responding to Sierra Club's use of the January 2013 four-unit scenario as a proxy for the October 2013 two-unit scenario?

A. In rebuttal testimony, Mr. Ralston testified that it was reasonable to assume that the two-unit costs increased at the same percentage as the four-unit costs in the Company's 2015 IRP fueling plan. This responded to Sierra Club's claim that the two-unit costs in the 2015 IRP fueling plan would have actually decreased to the level of four-unit costs in January 2013. The Company's updated analysis indicates that its previous estimate of two-unit coal costs in the 2015 IRP fueling plan, which projected only a [redacted] increase, was conservative.[25]

Q. Why didn't the Company update its two-unit scenario coal costs in fall 2013?

A. As I discuss above, nothing in the October 2013 mine plan raised concerns that the January 2013 long-term fueling plan was obsolete or that costs in the two-unit scenario were decreasing relative to costs in the four-unit scenario. Under these circumstances, updating the two-unit scenario was unnecessary.

OTHER ISSUES

Q. Staff testifies that they do not understand why the Company conducted analysis in its rebuttal testimony based on the Company's 2015 IRP fueling plan.[26] Why did the Company include that analysis in its rebuttal testimony?

A. As explained clearly in Mr. Ralston's rebuttal testimony, the Company was responding to Sierra Club's comparison of coal costs between the January 2013 long-

[25] Ralston, Exh. No. DR-1CT 12:10-14.
[26] Twitchell, Exh. No. JBT-28HCT 8:16 – 9:4.

term fueling plan and the long-term fueling plan used in the 2015 IRP.[27]

Q. Staff claims that the long-term fueling plan used in the 2015 IRP is "not relevant in evaluating the prudence of the Company's decision" because "it was prepared several months after Pacific Power issued the full notice to proceed (FNTP) with SCR installation at Bridger."[28] Do you agree?

A. Yes, in part. The Company generally agrees that the prudence standard examines whether a utility's decision was reasonable based on the information it knew or should have known at the time the decision was made. The data used in the 2015 IRP is therefore not relevant to the prudence of the Company's decision to install SCRs at Jim Bridger Units 3 and 4 because the data was developed after the Company made the decision in May 2013 and after it issued the FNTP on December 1, 2013. But in this case, Staff argues that "rising coal costs and falling natural gas costs"[29] between January 2013 and October 2013 demonstrate "obvious trends" that the Company willfully ignored before issuing the FNTP.[30] The analysis of the SCR investments using the 2015 IRP data is therefore relevant to rebut this argument and to verify that there was no significant long-term trend of increasing coal costs.

[27] Ralston, Exh. No. DR-1CT 6:4-9; 7:14 – 10:16.
[28] Twitchell, Exh. No. JBT-28HCT 8:17-19.
[29] Twitchell, Exh. No. JBT-28HCT 33:5-6.
[30] Twitchell, Exh. No. JBT-28HCT 31:18-19.

Q. One of the corrections Staff made in its supplemental testimony is to exclude non-cash operating costs (*i.e.*, depletion, depreciation, and amortization) from its analysis. While acknowledging its previous error, Staff faults the Company for failing to explain that non-cash operating costs were excluded from the SCR analysis.[31] How do you respond to Staff's allegation?

A. Staff's criticism of the Company is unwarranted. On January 20, 2016, Staff received the Company's response to Sierra Club's Data Request No. 11. That request referenced the Company's cash coal costs set forth in Exhibit No. RTL-3C and asked the Company to: "Identify, separately, the elements of Bridger Coal Company's costs which are specifically included and excluded in cash costs." The Company's response clearly indicated that amortization, depreciation, and depletion are excluded from the cash costs used in the Company's SCR analysis. This data response is attached as Exhibit No. CAC-4. Staff had this information well before filing its rebuttal testimony. In addition, my Utah testimony that Mr. Twitchell reviewed before filing his initial testimony,[32] described in detail how the Company removed the non-cash operating costs from its SCR analysis.[33]

CONCLUSION

Q. What is your recommendation to the Commission?

A. The Commission should conclude that the Company's SCR analysis was robust and its decision to install SCR systems on Jim Bridger Units 3 and 4 was prudent. The October 2013 mine plan showed increased operating cash costs, but those increasing

[31] Twitchell, Exh. No. JBT-28HCT 15:16 – 16:3.
[32] Twitchell, Exh. No. JBT-1T 62:1-4.
[33] Fisher, Exh. No. JIF-8 6:107 – 7:116.

costs were substantially offset by decreased capital and third-party costs, and by cost increases in the two-unit scenario. This shows that changes in coal costs during the period the SCR analysis was under review were adequately considered before the FNTP was issued, as demonstrated by the Company in its rebuttal testimony.

Q. Does this conclude your supplemental rebuttal testimony?

A. Yes.

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UE 374

SIERRA CLUB EXHIBIT 701

Cross-Examination Exhibit

UE 374/PacifiCorp
August 27, 2020
Sierra Club Data Request 11.1

Sierra Club Data Request 11.1

Refer to Exhibit PAC/2603 and the Reply Testimony of Dana Ralston (PAC/2600) at Ralston/10:11-11:7, with respect to the October 2013 mine plan, specifically that “SCR benefits would have decreased by approximately $16.7 million over the 10- year budget period”.

(a) Confirm or deny: the $16.7 million value is a present value calculated through the period 2014-2023 only. If denied, provide evidence and work papers showing that the present value was calculated through a different period.

(b) Please confirm whether Mr. Ralston calculated a differential in the SCR benefits through 2030 using the October 2013 mine plan? If he did not, please explain why not. If so, provide that calculation.

(c) Please confirm whether Mr. Ralston calculated a differential in the SCR benefits through 2037 using the October 2013 mine plan. If he did not, please explain why not. If so, provide that calculation.

Response to Sierra Club Data Request 11.1

(a) Confirmed.

(b) Not confirmed. The October 2013 mine plan was developed to support PacifiCorp’s 2014 10-year business plan process. As such, updated Jim Bridger plant million British thermal unit (MMBtu) requirements where only available through 2023.

(c) Please refer to the Company’s response to subpart (b) above.

Docket No. UE 374
Exhibit Sierra Club/702

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 702

Cross-Examination Exhibit

UE 374/PacifiCorp
August 27, 2020
Sierra Club Data Request 11.2

Sierra Club Data Request 11.2

Refer to the work papers supporting Exhibit PAC/2603, "CONF Exhibit_PAC_2603_CONF and WPs.xlsx, tabs "January 2013 Mine Plan" and "October 2013 Mine Plan".

(a) Provide a $/MMBtu estimate of the cost of coal procured from Bridger coal company for years 2014-2030 in January 2013 and October 2013.

Response to Sierra Club Data Request 11.2

(a) Please refer to Confidential Attachment Sierra Club 11.2 for Bridger Coal Company delivered coal cost. Bridger Coal Company coal costs after 2023 are high level estimates without Jim Bridger plant generation forecast and are only used to derive final reclamation contributions.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 704

Cross-Examination Exhibit

UE 374/PacifiCorp
August 27, 2020
Sierra Club Data Request 11.4

Sierra Club Data Request 11.4

Refer to PAC/4100 Ralston/9:11-19, specifically "my reply testimony made clear that the two-unit/no SCR analysis under the October 2013 mine plan would remove the $28.3 million reclamation cost increase."

(a) Confirm that a two-unit / no SCR analysis following the October 2013 mine plan would not have accelerated surface reclamation costs relative to a four-unit analysis. If denied, provide a precise reason why a two-unit / no SCR analysis after October 2013 would continue to have accelerated surface reclamation costs.

(b) Confirm that Mr. Ralston's estimate of a $16.7 million SCR benefit differential (see line 17) resulting from the October 2013 mine plan does not include a specific year-by-year two-unit scenario, calibrated to fuel supply as known in October 2013. If denied, provide a citation and reference to a two-unit scenario updated to October 2013, and provide underlying work papers.

(c) Confirm that Mr. Ralston's estimate of a $16.7 million SCR benefit differential does not adjust for the lack of accelerated surface reclamation costs relative to a four-unit analysis. If denied, explain, in detail, how Mr. Ralston's estimate accounts for a change in surface reclamation costs.

Response to Sierra Club Data Request 11.4

(a) Confirmed.

(b) Confirmed.

(c) Not confirmed for the four-unit scenario. In both the January 2013 and October 2013 four-unit scenarios, the surface mine was assumed to operate until 2037.

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SIERRA CLUB EXHIBIT 705

Cross-Examination Exhibit

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Sierra Club Data Request 11.5

Sierra Club Data Request 11.5

Refer to the work papers supporting PAC/2603, "CON Exhibit_PAC_2603_CONF and WPs.xlsx", tab "October 2013 Mine Plan," lines 140-143, labeled "two unit scenario" and NPV calculation, respectively.

(a) Confirm that the values in line 141 represent the total cost of fuel delivered to Jim Bridger in a two-unit scenario, from the years 2014-2023. If denied, provide a clarification on what is represented by the values in line 141.

(b) Confirm that the values in line 141 are derived from a January 2013 two-unit scenario fuel plan for Jim Bridger, as used in the Utah and Wyoming CPCNs. If denied, provide a clarification on source of the values in line 141.

(c) Refer, in addition, to work papers provided in Attach Sierra Club 9.1 CONF. Provide a citation to the source of line 141 of CONF Exhibit_PAC_2603_CONF and WPs.xlsx, tab "October 2013 Mine Plan" as contained in Mr. Ralston's work papers. If the source of these values are not contained in work papers as previously provided, provide a work paper showing the derivation of line 141.

(d) Confirm that the two unit scenario for Jim Bridger as derived in the January 2013 contemplated accelerated surface reclamation and associated recovery of surface reclamation dollars, as shown in Exhibit PAC/706. If denied, explain.

Response to Sierra Club Data Request 11.5

(a) Denied. The values represent a cash cost of fuel delivered. Cash coal costs exclude depreciation, depletion, amortization and coal inventory adjustments.

(b) Confirmed.

(c) The derivation is calculated by multiplying Bridger 2-unit annual coal cash price[1] by the System Optimizer (SO) model PAC Share Two-Unit annual Fuel Requirement[2]. In addition, this calculation was performed by Mr. Fisher in WA UE-152253[3].

(d) Confirmed.

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[1] Link Confidential Workpapers\SO Inputs and Outputs, CONF\Base Gas, Base CO2 (Gas, Outputs) CONF\StaMoFuel-C_M1209_16_B315_B416_NC.out
[2] Confidential Exhibit 705
[3] UE-152253_CONFIDENTIAL Fisher Workpapers_Revised cash and capital costs from Exhibit No. RTL-7C, Confidential Figure 3.xlsx, "SOModel – Base" tab, line 169

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, Request for a General Rate Revision	**UE 374**

Sierra Club Hearing Reference Materials

Cross Examination of Mr. Richard Vail

September 2, 2020

Sierra Club Reference Materials: Vail Cross Examination

Exhibit No.	Description	Pages Referenced	Confidential (Yes/No)
Sierra Club/722	PacifiCorp Response to Sierra Club Data Request 12.2	Entire document	No
Sierra Club/723	Attachment to Sierra Club 12.2 (Gateway West)	1-47t	No
Sierra Club/724	Attachment to Sierra Club 12.2 (Aeolus West)	Entire document	No
PAC/4200	Surrebuttal Testimony of Richard Vail	Vail/45-47	Yes
	PacifiCorp 2013 IRP (excerpt)	1-20	No

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SIERRA CLUB EXHIBIT 722

Cross-Examination Exhibit

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Sierra Club Data Request 12.2

Sierra Club Data Request 12.2

Refer to PAC/4200 at Vail/46:16-Vail/47:7, referring to the transmission constraints mitigated by Gateway Segment D.2:

(a) Identify the transmission studies produced by or available to the Company prior to December 1, 2013 which specifically identify the constraints and mitigations noted here.

(b) Provide the transmission studies identified in (a) above.

(c) Refer to Vail/46:17-18. How much "additional renewable generation" is added in eastern Wyoming before the "first transmission constraint" is identified? Identify the nameplate capacity and specific type of generation tested in the reliability or transmission model.

(d) Refer to Vail/46:17-18. As of December 1, 2013, in what year did PacifiCorp anticipate adding the "additional" amount of renewable generation identified in (c), above? Identify the source of information (IRP or other) specifying that amount of renewable generation in that year, if possible.

(e) Refer to Vail/46:20-22. How much additional renewable generation is added in the model when Mr. Vail refers to "increasing renewable generation" causing "the next transmission constraint"? Identify the nameplate capacity and specific type of generation tested in the reliability or transmission model.

(f) Refer to Vail/46:20-22. As of December 1, 2013, in what year did PacifiCorp anticipate adding the "increasing renewable generation" that caused "the next transmission constraint" as identified in (e), above? Identify the source of information (IRP or other) specifying that amount of renewable generation in that year, if possible.

(g) Refer to Vail/47:1-6. Under the "high transfer conditions" identified here, does the transmission model assume that Jim Bridger 3 & 4 are operational, or not?

(h) Refer to Vail/47:1-6. Specify the "high transfer conditions" studied here.

(i) Refer to Vail/47:6-7. Explain, in detail, why the existing 345 lines west of Jim Bridger would be overloaded "even if Units 3 and 4 at Jim Bridger were retired."?

(j) Refer to Vail/47:1-7. Did PacifiCorp examine the need for each individual segment of the Gateway West or Gateway South projects in the absence of

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generation from Jim Bridger 3 & 4? If so, identify and provide such studies. If not, why not?

(k) Refer to Vail/47:1-7. Did PacifiCorp examine alternative mitigations (i.e. line upgrades, substation upgrades, voltage support at key locations) to relieve transmission constraints from new expected renewable energy in the absence of generation from Jim Bridger 3 & 4? If so, identify and provide such studies. If not, why not?

Response to Sierra Club Data Request 12.2

(a) Prior to December 1, 2013, Western Electricity Coordinating Council (WECC) Path Rating studies were performed for nine transmission paths that were impacted by the addition of the Energy Gateway Project. The Western Interconnection transmission model used for the studies reflected the entire Energy Gateway Transmission project. Specific to the Energy Gateway West, the following report was prepared:

> "Energy Gateway Project – Stage 1, Bridger / Anticline West (New Path 19), Path C (New Path 20) Southbound, Aeolus West (New Path) Phase 2 Path Rating Report," Revision 5.0, dated March 24, 2010.

Subsequent to completing this technical study, PacifiCorp completed the "Aeolus West Transmission Path Transfer Capability Assessment" study, Revision 2.1, dated March 30, 2018, that focused specifically on adding the Energy Gateway West – Subsegment D.2 (Aeolus – Bridger/Anticline) Project prior to other Energy Gateway project facilities in Wyoming.

(b) Please refer to Attachment SC 12.2 which provides copies of the reports referenced in the Company's response to subpart (a) above.

(c) The current Wyoming transmission system has an existing transmission constraint on the TOT 4A transmission path. The addition of the D.2 Project mitigated this constraint and allowed for the addition of the LGI Q0706 (250 megawatts (MW)) wind generation, and with the addition of 230 kV network improvements an additional 1,020 MW of queued wind generation requests could be integrated. Higher Wyoming east to west transfers were realized on the Aeolus West transmission path, which was formed by combining the D.2 Project 500 kilovolt (kV) line flows with the TOT 4A path lines flows.

Path rating studies referenced in (a) above assumed Wyoming renewable resources that were included in the Revised 2008 Integrated Resource Plan (IRP) Preferred Portfolio (May 28, 2009) totaling 2,156 MW, which would be added between 2008 and 2018. Additionally, please refer to the preferred portfolio selections of the 2013 IRP indicating 432 MW of Wyoming Wind in 2024 and an additional 218 MW of Wyoming Wind in 2025 (Table 8.7). As

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described in Table 7.5, Energy Gateway Scenario Definitions, the preferred portfolio EG-02 Case-07a included Gateway segment D.

(d) The Energy Gateway West - Subsegment D.2 and ancillary projects identified in the related interconnection studies for the renewable projects, enabled interconnection of another 1,270 MW of new wind facilities. Any further interconnections in the eastern Wyoming area would require addition of the Energy Gateway South (Aeolus-Clover) Project as referenced in the Surrebuttal Testimony of Company witness Rick A. Vail, Exhibit PAC/4200, Vail 46/22 through Vail 47/1.

(e) Per PacifiCorp's 2017R Request for Proposals, this renewable generation would need to be in-service in 2020. Please refer to the Company's response to subpart (d) above.

(f) The WECC 2021-22 heavy winter base case that was used for the simulation reflected generation resource requirements in a time period before Jim Bridger unit retirements were considered.

(g) The higher transfer conditions referenced are specific to flows on both Aeolus West and Aeolus South being increased to as high a 1,700 MW.

(h) With both Energy Gateway West – Subsegment D.2 (Aeolus – Bridger/Anticline) and Energy Gateway South (Aeolus – Clover) projects in-service, loaded simultaneously to 1,700 MW, if it is assumed that Jim Bridger Unit 3 and Jim Bridger Unit 4 are retired, there are enough remaining resources at Jim Bridger coupled with eastern Wyoming wind generation to load the Bridger West transmission path to the 2,400 MW path rating. Under this high transfer condition, if the Gateway South line trips the remaining power will flow on the Aeolus West and Bridger West transmission paths overloading the existing 345 kV lines west of Jim Bridger above their thermal ratings.

(i) Not specifically. The scope and nature of the Energy Gateway Project has been modified over time to meet the resource needs of PacifiCorp customers.

The determination of the status of the PacifiCorp coal fleet is driven by economics and regulatory requirements that are reflected in the IRP analysis. Once a coal retirement decision is made, a formal large generator interconnection (LGI) request will be submitted to PacifiCorp Transmission to trigger a detailed evaluation to determine the impact that this coal retirement would have on the PacifiCorp transmission system. Short of such a request, any determination on the impacts of such a coal retirement are considered preliminary.

(j) The rating of the Bridger West transmission path was increased from 2,200 MW to 2,400 MW in 2011, prior to the completion of the Bridger/Anticline West path rating, which increased transfers west of Bridger/Anticline by 1,700 MW, up to 4,100 MW. As part of the 2011 path rating analysis, every facility was reviewed and upgraded as necessary. Therefore, any increase in the Bridger West transmission system will require transmission additions between Anticline and Populus. Technical studies evaluating the Bridger/Anticline path rating of 4,100 MW are included in the attached report:

> "Energy Gateway Project – Stage 1, Bridger / Anticline West (New Path 19), Path C (New Path 20) Southbound, Aeolus West (New Path) Phase 2 Path Rating Report," Revision 5.0, dated March 24, 2010.

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SIERRA CLUB EXHIBIT 723

Cross-Examination Exhibit

Energy Gateway Project – Stage 1

Bridger / Anticline West (New Path 19)

Path C (New Path 20) Southbound

Aeolus West (New Path)

Phase 2 Path Rating Report

Submitted by

WECC Phase 2 - Bridger Area Study Group

Date;

November 24, 2010

Revision 5.0

Appendix 21 – Pages C20 – C23 from TSS Accepted Exceptions to NERC/WECC Standards

APPENDIX FILES; Located on Idaho Power's FTP Site at; https:\\fileexch.idahopower.com

Appendix 6-1; See file; Appendix_6-1.pdf Aeolus West vs. Aeolus South – Base Case & PT Plots
Appendix 6-2; See file; Appendix_6-2.pdf Aeolus West vs. Aeolus South – Dynamics plots
Appendix 7-1; See file; Appendix_7-1.pdf Aeolus West vs. Bonanza West – Base Case & PT Plots
Appendix 7-2; See file; Appendix_7-2.pdf Aeolus West vs. Bonanza West– Dynamics plots
Appendix 8-1; See file; Appendix_8-1.pdf Aeolus West vs. Tot 1a – Base Case & PT Plots
Appendix 8-2; See file; Appendix_8-2.pdf Aeolus West vs. Tot 1a– Dynamics plots
Appendix 9-1; See file; Appendix_9-1.pdf Bridger West vs. Aeolus South - Base Case & PT Plots
Appendix 9-2; See file; Appendix_9-1.pdf Bridger West vs. Aeolus South– Dynamics plots
Appendix 10-1; See file; Appendix_10-1.pdf Bridger West vs. Path C South – Base Case & PT Plots
Appendix 10-2; See file; Appendix_10-2.pdf Bridger West vs. Path C South– Dynamics plots
Appendix 11-1; See file; Appendix_11-1.pdf Bridger West vs. Bonanza West – Base Case & PT Plots
Appendix 11-2; See file; Appendix_11-2.pdf Bridger West vs. Bonanza West – Dynamics plots
Appendix 12-1; See file; Appendix_12-1.pdf Bridger West vs. Idaho – Montana (18) Base Case+PT Plots
Appendix 12-2; See file; Appendix_12-2.pdf Bridger West vs. Idaho – Montana (18) – Dynamics plots
Appendix 13-1; See file; Appendix_13-1.pdf Bridger West vs. Monument–Naughton Base Case+PT Plots
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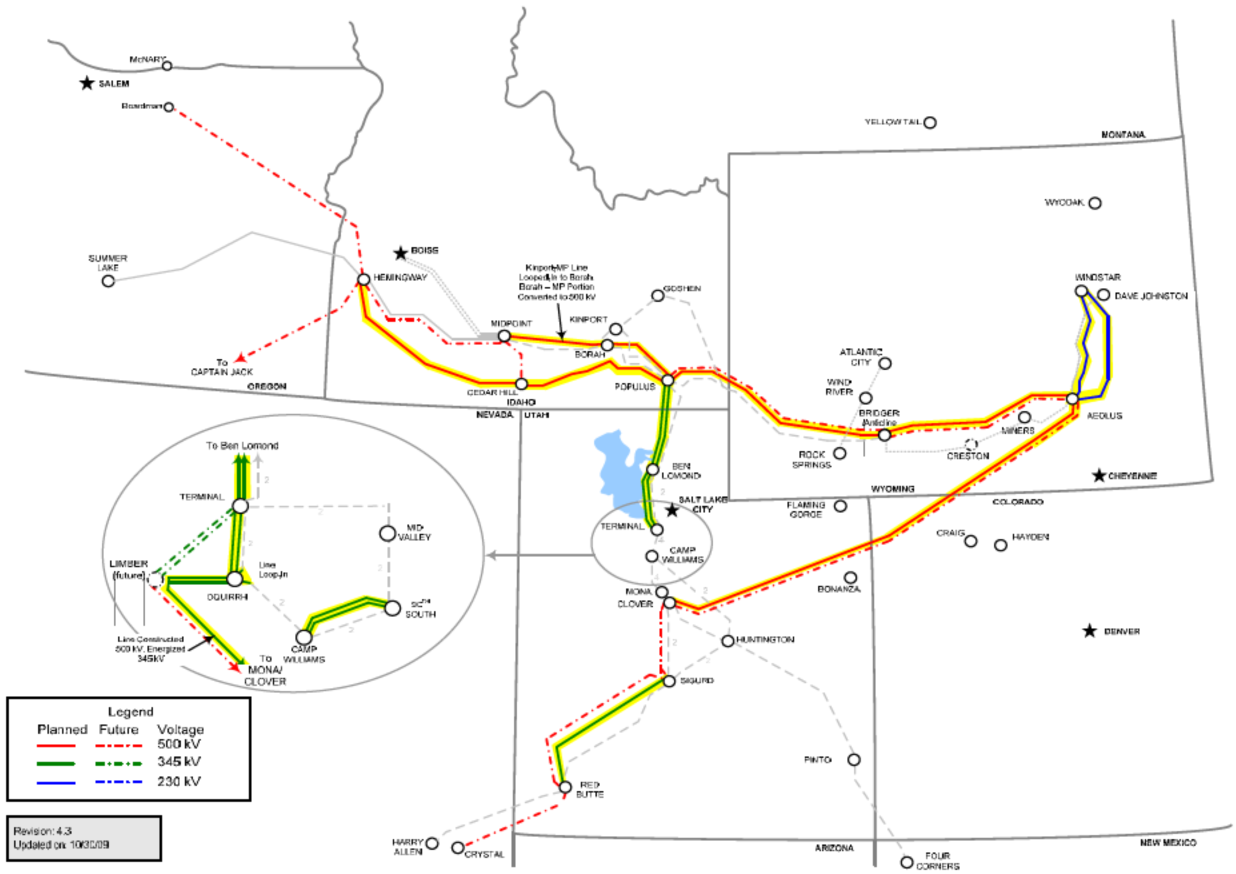
Appendix 20-1; See file; Appendix_20-1.pdf Path C South vs. Rock Spgs / Firehole– Base Case & PT Plots
Appendix 20-2; See file; Appendix_20-2.pdf Path C South vs. Rock Spgs / Firehole– Dynamics plots

Executive Summary

PacifiCorp plans to build a 500 kV transmission Project to deliver wind power from central Wyoming to central Utah and eastern Idaho. The Project consists of 500 kV transmission from central Wyoming to central Utah and a second set of 500 kV lines from Wyoming to the eastern Idaho area and eventually to the lower Columbia River system in north central Oregon. The project also consists of a 230 kV collector system in Wyoming, which delivers the output of various wind farms to a 500 / 230 kV central hub called Aeolus. Just to the northwest of the existing Dave Johnston plant, a second 230 kV hub station called Windstar will be developed with 230kV tie lines to Aeolus. See Figure 1 for a geographic depiction of the proposed facilities that comprise 'Stage 1' of the ultimate build-out plan for the system. As noted in the Legend, Stage 1 consists of the solid lines only.

Figure 1
Gateway Energy Project
Stage 1 - Transmission Plan



This study covers the "Bridger Area" and includes the following primary paths;

- Aeolus West
- Bridger / Anticline West
- Path C Southbound

This study shows that the proposed project meets all applicable NERC Planning Standards and WECC System Performance Criteria with minor modifications to the originally proposed plan of service.

At the start of this study, Idaho Power and PacifiCorp agreed that the Bridger West 345 kV path be studied only at 2400 MW, a 200 MW upgrade from the existing rating of 2200 MW.

1. Introduction

This report establishes that, at the proposed transfer levels, the Bridger Area of the Gateway West system has little to no impact on paths external to PacifiCorp and Idaho.

1.1. Project Description

As shown in Figure 1, the Gateway West system consists of a 230kV collector system for various wind farms in central and western Wyoming. These systems either connect to the "Tot 4a" 230kV lines or connect directly to the Windstar and Aeolus hubs. From Aeolus extends a 500 kV line to Anticline, in the Bridger vicinity, and then on to Populus. Other portions of the Gateway West project will consist of 500 kV lines from Populus to Midpoint and Hemmingway, and on to Slatt substation in Oregon. A second 500 kV line from Aeolus will extend through northwestern Colorado and into a new substation called Mona Annex (or Clover) located with a few miles of the existing Mona 345kV station.

1.2. Plan of Service

.See Appendix 5 for the Gateway West Study Plan (2010 01 19 V9 - Phase I II GW Study Plan.doc) for a detailed listing of the project components.

1.3. Planned Operating Date

The plan of service provides for the Aeolus West stage one facilities to be operational by 2016 or 2017. The Aeolus South stage two facilities will be operational by 2017 to 2019

2. Transfer Capability

This report intends to prove that the Gateway West Project has little or no significant impact to paths external to PacifiCorp. In the few instances where impacts are identified, simultaneous flow impacts will be respected. In some cases, impact remediation facilities will be installed.

Early on in this study, a request was received to analyze possible increases in the study plan table of desired capacities to allow some flexibility of delivery to Aeolus South or Aeolus West. Table 1 shows the originally proposed path ratings and actual ratings achieved.

Table 1

WECC Path Name / Number	Proposed Stage 1 Rating	Path Rating Achieved in this study
Aeolus West[1] (New)	1500 MW	2672 MW
Bridger / Anticline West (19)	3900 MW	4100 MW
Path C (20) Southbound	2250 MW	2250 MW

The above ratings are all based on a heavy summer representation for the 2019 time frame. An analysis of a lighter load condition to study Path C northbound was requested, but a PRG approved base case was not delivered in time to be included in this study. The Path C northbound path rating will be addressed in a separate report.

The path transfer capability is limited due to NERC/WECC reliability performance requirements. The NERC/WECC "Reliability Criteria" is available at the following link: http://www.wecc.biz/documents/library/procedures/CriteriaMaster.pdf

3. Study Methods and Standards

3.1. Steady-State Case Stressing

Details of how each study base case was developed can be found in the Base Case Development sections of the studied system flow conditions.

3.2. Post Transient

The power flow conditions generated above are modeled with single line (N-1) outages, credible double line (N-2) outages, breaker failure outages, as well as risk assessment outages to evaluate the NERC/WECC category B, and C performance. All modeled system bus voltages and line, transformer, and series capacitor current flows are monitored. Voltage deviations greater than 5% and significant overloaded elements, with greater than a 2% change in flow, are reported in the tables located in the appendices. Engineering judgment was used to determine whether the overloading was relevant to the area. For example, some contingencies in the PACE area caused parallel transformer tap changers in B.C.Hydro and Alberta to head in opposite directions, leading to circulating Vars overloading the transformers. These loading issues are clearly a defect in modeling built into the original base cases and these loadings have not been included in the reports.

For PacifiCorp's Wyoming system, voltages less than .90 pu are reported. For Montana buses on Path 18 for Level B and C contingencies, .90 pu voltage is required. For Idaho and PacifiCorp Path 18 buses, voltages less than .87 pu are limiting for Level B and C contingencies. For Level C contingencies, under-voltage load tripping at Amps, Peterson Flats, and Big Grassy is allowed to restore system voltages.

[1] The study plan definition of Aeolus West as only the Aeolus – Anticline 500 kV line. During the course of this study, the definition was modified to include three 230 kV lines.

Violations of the NERC/WECC allowed performance are identified in the summary paragraphs for each path relationship / nomogram section.

3.3. Reactive Margin

Idaho Power's reactive margin requirements are;

- For N-1 outages; 500 MVAR for 500 kV and 250 MVAR for 345 and 230 kV.
- For N-2 outages; 400 MVAR for 500 KV and 200 MVAR for 345 and 230 kV

For this study, Idaho is assumed to be the owner of the following margin tested buses;

- Borah 500
- Borah 345
- Kinport 345
- Midpoint 500
- Hemmingway 500
- Cedar Hill 500

The WECC also requires that new rated paths or facilities be scheduled at 2.5% for all level C contingencies and 5% over their rated capacities for Level B contingencies to test for voltage collapse. Each starting nomogram corner case was modified to increase the flow by 5% and checked that a solution was attained for each outage.

3.4. Transient Stability

Utilizing GE PSLF software, select single line (N-1) and double line (N-2) and other outages were studied to evaluate transient stability performance. Relevant bus voltage and frequency violations of the NERC/WECC allowed performance are documented in Appendix 4.

3.5. Generation Drop via Remedial Action Schemes (RAS)

In order to maintain PacifiCorp's current level of reserve requirements (for Bridger contingencies), Wyoming wind generation dropping via RAS was limited to 600 MW for single line outage contingencies (N-1) and 1200 MW for double line outage contingencies.

4. Path Definitions

Both new and existing path definitions are as follows, with a '*' denoting the metering points.

4.1. Aeolus West (New)

The Aeolus West transmission path is a constrained path and is defined as the sum of the flows on the following lines: (this defn differs from the study plan)

- Aeolus* – Anticline 500 kV
- Platte* – Latham 230 kV
- Mustang* - Bridger 230 kV

- Riverton* - Wyopo 230 kV

4.2. Aeolus South (New)

The Aeolus South path is a constrained path and is defined as the sum of the flows on only one line:

- Aeolus* – Mona Annex 500 kV

4.3. Bridger West 345 kV (Existing)

The Bridger / Anticline West constrained path and is defined as the sum of the flows on the following lines:

- Bridger* – 3 Mile Knoll 345 kV
- Bridger* – Populus 345 kV #1
- Bridger* – Populus 345 kV #2

Bridger West, comprising only the existing 345 kV lines from Bridger, is currently rated at 2200 MW. With the Gateway West Project, this path rating is planned to increase to 2400 MW.

4.4. Bridger / Anticline West (Modified)

The Bridger / Anticline West constrained path and is defined as the sum of the flows on the following lines:

- Anticline* – Populus 500 kV
- Bridger* – 3 Mile Knoll 345 kV
- Bridger* – Populus 345 kV #1
- Bridger* – Populus 345 kV #2

With the Gateway West Project this Path is anticipated to be rated at 4100 MW.

4.5. Path C (Existing – After completion of the Populus –Terminal Project)

Path C is a constrained path and is defined as the sum of the flows on the following lines:

- Terminal – Populus* 345 kV
- Ben Lomond – Populus* 345 kV #2
- Ben Lomond – Populus* 345 kV #3
- Treasureton – Brady* 230 kV
- Fish Creek – Goshen* 161 kV
- Malad - American Falls *138 kV
- 3 Mile Knoll 138 / 345* kV Transformer
- 3 Mile Knoll* - Hooper Spur 138 kV

After completion of the Populus – Terminal Project, Path C will have a southbound rating of 1600 MW and a northbound rating of 1250 MW. With the Gateway West Project, the Path C rating goals are 2250 MW bi-directional.

4.6. Monument – Naughton (Internal Path)

Monument – Naughton is a path internal to PacifiCorp, is not registered with the WECC, and is defined as the sum of the flows on the following lines:

- Monument PST* – Craven Creek 230 kV
- Monument PST* – Naughton 230 kV

4.7. West of Rock Springs / Firehole (Internal Path)

Monument – Naughton is a path internal to PacifiCorp, is not registered with the WECC, and is defined as the sum of the flows on the following lines:

- Rock Springs* – Palisade 230 kV
- Firehole* - Mansface 230 kV

5. Project Base Case Modifications

The following describes various changes to the base cases to resolve PSLF solution convergence issues.

5.1. SVC Tie Line Modeling

At St. George, Red Butte, Platte, and Aeolus, tie lines between the SVC and the main substation bus had too low an impedance to obtain reliable solutions in PSLF. These impedances were adjusted to be above the Z threshold to get the cases to reliably converge. In some instances, the Red Butte SVC had to be disconnected to obtain a valid solution.

5.2. Line and Transformer Rating Conflicts

From the original WECC base cases there are some instances where the emergency ratings (MVA2) are lower than the normal ratings (MVA1). The consequences of this are that the Post-transient flow program output would get clogged with reports of overloads that are not real. To reduce the erroneous reports, a program was run to set the emergency ratings at least equal to the normal ratings.

5.3. Phase Shifter Tap Steps

Most of the controlled flow phase shifter tap steps were changed to zero degrees to allow for fine tuning of the path flows.

5.4. SVDs to Shunt Conversions

In the PacifiCorp system, many of the Static Var Devices (SVDs) were disconnected and replaced with shunt capacitors and reactors to allow forcing of the devices to correct voltage profiles while keeping generator reactive within reasonable limits.

5.5. Other System Modeling Changes / Corrections

Several cases involving heavy Path C southbound flows resulted in Aeolus flows greater than 1700 MW. To keep the Aeolus south flows within the 1700 MW limit, a small portion of the series capacitors closest to Aeolus were bypassed (by modifying the bank impedance) on the Aeolus – Mona Annex 500 kV line.

On the starting base case, errors were noted on the PDCI B-Face table such that the PDCI flows were being incorrectly reported. This was corrected via an epcl routine.

5.6. PacifiCorp System Updates / Corrections

Through the course of the study, modeling errors were noted in both the existing system in the Gateway West proposed facilities. To track case versions, these changes also describe case version code changes;

1. Early on in the studies, a reactive deficiency at Bonanza was noted. At the recommendation of Deseret Energy, the 345 kV line reactor was removed from the Bonanza – Mona 345 kV line and a 60 MVar shunt capacitor was added to the Bonanza 138 kV bus. A previously suggested load addition at Chapita 138 was not added due to the lack of a plan of service study. At about the same time it was noted that the SVDs modeled at the Tot 4a 230kV buses were causing the PT cases to diverge. To fix this problem, the SVDs were converted to shunts and switched via RAS in the switching files. These changes, along with a rating change of the Malad – American Falls 138 kV line were incorporated into cases identified by the version code ‘8h5’.
2. An error was found in the conversion of the cases from PSSE to PSLF in the shunt tables. In PSSE, shunts are part of the bus records, and if they are off line, they are simply deleted from the record. When converting to PSLF, this information is lost. An EPCL was developed to incorporate the original shunt tables from the parent WECC case. The case version code for this change was ‘8h6’.
3. In the approved project case, only transformer and phase shifters connected to Anticline 500 kV to Bridger 345. A change was requested to add the 5 mile section of 345 kV line between Anticline and Bridger with the transformers and phase shifters located at Anticline. Also, the addition of Riverton – Wyopo 230 kV line to the Aeolus West interface. The case version code for this change was ‘8h7’.
4. Errors were noted in the representation of the Aeolus area shunts and SVC. The SVC was increased to +450 MVar. At this same time, the fixed SVD at Spence was removed and replaced with a switchable shunt and the Pinto phase shifter impedance was corrected. The case version code for this change was ‘8h8’.
5. After it was found that the Platte – Miners and Platte – Latham 230 kV lines were constraining Aeolus West flows, it was decided to change the emergency rating (MVA2) to the 30 minute rating of 521 MVA for both of these lines. As the network topology did not change, the version code remained at ‘8h8’.

6. Path Studies

6.1. Aeolus West vs. Aeolus South

6.1.1. Base Case Development

The Gateway West Project base case was modified to stress Aeolus West to 2672 MW with several cases spanning a range of Aeolus South flows. The primary resource for stressing Aeolus West was the Wyoming Wind developments. Aeolus South flows were stressed by varying; 1) Current Creek generation, 2) IPP DC flows and the wind generation connected to IPP 345, and lastly, Nevada generation and Tot 2C flows.

For cases with Aeolus South flows at 1700 MW, Aeolus West flows were fine tuned by varying schedules from WAPA (73) to the Northwest (40). Shunt capacitors were added to Mona Annex 500 kV to support the high flows into central Utah. Path flows for each of the above cases are shown on Appendix 3-1. The resulting nomogram is shown on Appendix 2-1.

Finally, two margin test cases were developed with 5% additional flows across 1) Aeolus West path and 2) Aeolus South path. These cases are shown near the bottom of Appendix 3-1.

6.1.2. Post-Transient Analysis

Appendix 3-1 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

  This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) becomes the limiting contingency for both nomogram corners. This outage results in overloads on the Miners – Platte 230 kV line even when the 521 MVA 30 minute emergency rating is used, and thereby sets the PT limit for this contingency.

- **Aeolus – Mona Annex (Clover) 500 kV Line (Contingency B36 and RAS variations)**

  This contingency also diverges without any RAS actions. However, with 600 MW of generation dropping and 500 kV and 230 kV switchable capacitor applications, the contingency problems are fully resolved.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. Some voltage deviation problems are noted, but these issues are fully mitigated with RAS switching.

- **<u>Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)</u>**

This outage resulted in overloads of the Bridger – Rock Springs 230kV line. Follow-up cases with Bridger generation dropping and additional RAS action on Path 18 resolve both the loading problem and the voltage deviation issues on Path 18.

- **<u>Palo Verde 2-unit loss with FACRI (N-2)</u>**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in overloads of Springer – Gladstone 115 kV line for one corner point of the nomogram and an overload of Merwin – View Tap 115kV line for the other corner point. Springer – Gladstone is a known problem for which remediation is already planned. The Merwin – View tap problem is also a known problem related to north to south flows on transmission into the Vancouver, WA and Portland, OR loads.

6.1.3. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-1. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.1.4. Transient Stability Analysis

As shown on Appendix 4-1, dynamic simulations were run on both nomogram corner points. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. However, these deviations are within the exceptions for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

Contingency B16 (Aeolus – Mona Annex 500 kV line) also produced voltage deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies. Blundel #2 also lost synchronism and went out-of-step. Blundel #2 is known as having modeling problems where the unit losses synchronism for very remote faults. This result is not relevant to this study.

6.2. Aeolus West vs. Bonanza West

6.2.1. Base Case Development

The Gateway West Project base case was modified to stress Aeolus West to 2666 MW with several cases with Bonanza West flows at 785 MW and 685 MW. The primary resource for stressing Aeolus West was the Wyoming Wind developments. Bonanza West flows were stressed by varying; 1) Current Creek generation, and 2) IPP DC flows and the wind generation connected to IPP 345. From the starting point (2666, 785) Aeolus West flows were cut by 100 MW to 2566 MW by varying schedules from WAPA (73) to the Northwest (40). Path flows for each of the above cases are shown on Appendix 3-2. The resulting nomogram is shown on Appendix 2-2.

Two margin test cases were developed with 5% additional flows across 1) Aeolus West path and 2) Bonanza West path. These cases are shown near the bottom of Appendix 3-2.

6.2.2. Post-Transient Analysis

Appendix 3-2 contains the tables associated with the post-transient study results for the Aeolus West vs. Bonanza West cases. A discussion of several of the prominent outages follows.

- **<u>Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)</u>**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **<u>Bridger – 3 Mile Knoll 345 kV Lines (B04 and RAS variations)</u>**

  For this outage, loadings are within emergency ratings. However, voltage deviations and deviations from the .90 pu standard for Path 18 are noted. Subsequent simulations with RAS actions fully resolve these issues.

- **<u>Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)</u>**

  This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) becomes the limiting contingency for both nomogram corners. This outage results in overloads on the Miners – Platte 230 kV line even with the 521 MVA 30 minute emergency rating, and thereby sets the PT limit for this contingency.

- **<u>Aeolus – Mona Annex (Clover)500 kV Line (Contingency B36 and RAS variations)</u>**

This contingency also diverges without any RAS actions. However, with 600 MW of generation dropping and 500 kV and 230 kV switchable capacitor applications, the contingency problems are fully resolved.

- **Bonanza – Mona 345 kV Line (B40 and B40a with RAS)**

For this outage, a total of 10 elements overload, with the worst being the Bonanza – Vernal 138 kV line that loads to 133.42% of its emergency rating. Contingency 40a, with the existing Bonanza generation dropping RAS, fully resolves the loading and voltage deviations issues.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. Some voltage deviation problems are noted, but these issues are fully mitigated with RAS switching.

- **Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)**

This outage resulted on overloads of the Bridger – Rock Springs 230kV line. Follow-up cases with Bridger generation dropping and additional RAS action on Path 18 resolve both the loading problem and the voltage deviation issues on Path 18.

- **Palo Verde 2-unit loss with FACRI (N-2)**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in overloads of Springer – Gladstone 115 kV line. Springer – Gladstone is a known problem for which remediation is already planned.

6.2.3. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-2. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.2.4. Transient Stability Analysis

As shown on Appendix 4-2, , dynamic simulations were run on both nomogram corner points. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. For contingency B09c, the backswing exceeded the "exceptions" for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger. If this deviation is determined to be acceptable and not a risk to tripping the Bridger units, an amendment to the WECC exceptions list could easily resolve this issue.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

Contingency B16 (Aeolus – Mona Annex (Clover) 500 kV line) for the second base case (785, 2666) also produced voltage deviations and a over-excitation limiter (OEL1) relay trip of the Bonanza unit. Follow-up RAS cases with generation drop RAS and capacitor switching did not resolve the OEL trips. A further investigation into the OEL1 relay resulted in new relay data from Deseret Energy. However, the new data also resulted in a trip of Blundel #2 in addition to the OEL trip of Bonanza. After checking the dynamics plots it was found that the excitation current was well below the OEL1 trip setting. A further test with the trip functions of the OEL relay disabled produced stable operation and generator filed currents well within the maximums. From this, it is concluded to be a relay / modeling problem and is not a problem associated with Gateway West transfers. If a more detailed analysis determines Bonanza OEL1 relay settings to be correct and the field current to be a real problem, a 60 MVar switchable cap (#2) could be added to get the generator off its excitation / Var limits. This sensitivity analysis is provided on line 86 of Appendix 4-2.

6.3. Aeolus West vs. Tot 1a

6.3.1. Base Case Development

The Gateway West Project base case was modified to stress Aeolus West to 2672 MW with several cases with Tot 1a flows at 650 MW and 550 MW. The primary resource for stressing Aeolus West was the Wyoming Wind developments. Tot 1a flows were stressed by varying; 1) Bonanza generation, 2) Craig / Hayden generation, 3) Current Creek generation, and 4) IPP DC flows and the wind generation connected to IPP 345. Craig #3 generation was modeled at 430[2] MW which is above the governor limit shown in the dynamics data file. From the starting point (2672, 650) Aeolus West flows were cut by 100 MW to 2572 MW by varying schedules from WAPA (73) to the Northwest (40). Path flows for each of the above cases are shown on Appendix 3-3. The resulting nomogram is shown on Appendix 2-3.

One margin test cases was developed with 5% additional flows across the Aeolus West path and Tot 1a. These cases are shown near the bottom of Appendix 3-3.

6.3.2. Post-Transient Analysis

Appendix 3-3 contains the tables associated with the post-transient study results for the Aeolus West vs. Bonanza West cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

[2] An email request for this modeling change was made to Tri-State on June 17, 2010. As of this writing, no response has been received.

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **Bridger – 3 Mile Knoll 345 kV Lines (B04 and RAS variations)**

For this outage, loadings are within emergency ratings. However, voltage deviations and deviations from the .90 pu standard for Path 18 are noted. Subsequent simulations with RAS actions fully resolve these issues.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) becomes the limiting contingency for both nomogram corners. This outage results in overloads on the Miners – Platte 230 kV line even with the 521 MVA 30 minute emergency rating, and thereby sets the PT limit for this contingency.

- **Aeolus – MonanX (Clover) 500 kV Line (Contingency B36 and RAS variations)**

This contingency also diverges without any RAS actions. However, with 600 MW of generation dropping and 500 kV and 230 kV switchable capacitor applications, the only issues remaining are voltage deviations greater than 5% in the Bonanza area. A shunt capacitor, discussed later in this report, may be available to bring the Bonanza generator off of its upper Var limit and thereby reduce the voltage deviations to acceptable limits.

- **Bonanza – Mona 345 kV Line (B40 and B40a with RAS)**

For this outage, a total of 10 elements overload, with the worst being the Boanza – Vernal 138 kV line that loads to 133.42% of its emergency rating. Contingency 40a, with the existing gen drop RAS, fully resolves the loading and voltage deviations issues.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. Some voltage deviation problems are noted, but these issues are fully mitigated with RAS switching.

- **Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)**

This outage resulted on overloads of the Bridger – Rock Springs 230kV line. Follow-up cases with Bridger generation dropping and additional RAS action on Path 18 resolve both the loading problem and the voltage deviation issues on Path 18.

- **Palo Verde 2-unit loss with FACRI (N-2)**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in overloads of Springer – Gladstone 115 kV line. Springer – Gladstone is a known problem for which remediation is already planned.

6.3.3. Reactive Margin Analysis

As shown near the bottom of Appendix 3-3, One simultaneous case was developed with +5% on Aeolus West and Tot 1a. This case solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.3.4. Transient Stability Analysis

As shown on Appendix 4-3, dynamic simulations were run on both nomogram corner points. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. For contingency B09c, the backswing exceeded the exceptions for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger. If this deviation is determined to be acceptable and not a risk to tripping the Bridger units, an amendment to the WECC exceptions list could easily resolve this issue.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

Contingency B16 (Aeolus – Mona Annex (Clover) 500 kV line) for the second base case (650, 2522) resulted in an over-excitation limiter (OEL1) relay trip of the Bonanza unit. Follow-up RAS cases with generation drop RAS and capacitor switching did not resolve the OEL trips. A further investigation into the OEL1 relay resulted in new relay data from Deseret Energy. However, was not successful in elimination of the Bonanza OEL trip. After checking the dynamics plots it was found that the excitation current was well below the OEL1 trip setting. A further test with the trip functions of the OEL relay disabled. The resulting run produced stable operation and generator filed currents well within the maximums. From this, it is concluded to be a relay / modeling problem and is not a problem associated with Gateway West transfers. If a more detailed analysis determines Bonanza OEL1 relay settings to be correct and the field current to be a real problem, a 60 MVar switchable cap (#2) could be added to get the generator off its excitation / Var limits.

6.4. Bridger / Anticline West vs. Aeolus South

6.4.1. Base Case Development

The Gateway West Project base case was modified to stress Bridger / Anticline West to 4100 MW with several cases spanning a range of Aeolus South flows from 1500 MW to 1700 MW. The primary resource for stressing Bridger / Anticline West was the Wyoming Wind developments. Aeolus South flows were controlled by varying; 1) Current Creek generation, 2) IPP DC flows and the wind generation connected to IPP 345, and lastly, Nevada generation and Tot 2C flows.

For cases with Aeolus South flows at 1700 MW, Bridger / Anticline West flows were fine tuned by varying schedules from WAPA (73) to the Northwest (40). Shunt capacitors were added to Mona Annex (Clover) 500 kV to support the high flows into central Utah. Path flows for each of the above cases are shown on Appendix 3-4. The resulting nomogram is shown on Appendix 2-4.

Finally, two margin test cases were developed with 5% additional flows across 1) Aeolus West path and 2) Aeolus South path. These cases are shown near the bottom of Appendix 3-4.

6.4.2. Post-Transient Analysis

Appendix 3-4 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

  This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) becomes the limiting contingency for both nomogram corners. For the upper left nomogram corner point, this outage results in overloads of the Bridger 345 / 230 kV transformer #2, and thereby sets the PT limit. For the lower right nomogram point, this outage results in overloads of three critical elements, the worst of which is the Miners – Platte 230 kV line.

- **<u>Aeolus – Mona Annex (Clover) 500 kV Line (Contingency B36 and RAS variations)</u>**

This contingency also diverges without any RAS actions. However, with 600 MW of generation dropping and 500 kV and 230 kV switchable capacitor applications, the contingency problems are fully resolved.

- **<u>Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)</u>**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. Some voltage deviation problems are noted, but these issues are fully mitigated with RAS switching.

- **<u>Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)</u>**

This outage resulted on overloads of the Bridger – Rock Springs 230kV line. Follow-up cases with Bridger generation dropping and additional RAS action on Path 18 resolve both the loading problem and the voltage deviation issues on Path 18.

- **<u>Palo Verde 2-unit loss with FACRI (N-2)</u>**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in overloads of Springer – Gladstone 115 kV line. Springer – Gladstone is a known problem for which remediation is already planned.

6.4.3. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-4. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho’s reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.4.4. Transient Stability Analysis

As shown on Appendix 4-4, dynamic simulations were run on cases near the nomogram corner points. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. However, these deviations are within the “exceptions” for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

Contingency B16 (Aeolus – Mona Annex (Clover) 500 kV line) also produced voltage deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

6.5. Bridger / Anticline West vs. Path C Southbound

6.5.1. Base Case Development

The Gateway West Project base case was modified to stress Bridger / Anticline West to 4100 MW with several cases spanning a range of Path C Southbound flows from 1450 to 1550 MW. The primary resource for stressing Bridger / Anticline West was the Wyoming Wind developments. Path C Southbound flows were controlled by varying; 1) Northwest (40) generation, and 2) PACE area generation including Current Creek, Lakeside, and Huntington.

A second case with Path C southbound flows at 2250 MW, and Bridger / Anticline West reduced to 3900 MW was very difficult to schedule without overloading the Aeolus South path. Additional cases with higher Bridger / Anticline West were not attainable. The resulting nomogram is shown on Appendix 2-5.

Two margin test cases were developed with 5% additional flows across 1) Bridger / Anticline West and 2) Path C Southbound. These cases are shown near the bottom of Appendix 3-5.

6.5.2. Post-Transient Analysis

Appendix 3-5 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

  This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) resolves the voltage deviation problems. The Jefferson phase shifter overload shown is based on an emergency rating of 100 MVA. When corrected to the true rating of 112 MVA, the overload is resolved.

- **Aeolus – MonanX (Clover) 500 kV Line (Contingency B36 and RAS variations)**

This contingency also diverges without any RAS actions. With 600 MW of generation dropping and 500 kV and 230 kV switchable capacitor applications, the Grace – Soda 138 kV line remains overloaded, indicating the need for bypassing ½ of the 3 Mile Knoll series capacitor or reconductoring of the Grace – Soda 138 kV line.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. Some voltage deviation problems are noted, but these issues are fully mitigated with RAS switching.

- **Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)**

This outage resulted in an overload of the Bridger – Rock Springs 230kV line. Follow-up cases with Bridger generation dropping and additional RAS action on Path 18 resolve both the loading problem and the voltage deviation issues on Path 18.

- **Path C Double Line Outages (Contingencies C09, C10, C11, & C12)**

This outage resulted in an overload of the Grace – Soda 138 kV line, indicating the need for bypassing ½ of the 3 Mile Knoll series capacitor or reconductoring of the Grace – Soda 138 kV line.

- **Palo Verde 2-unit loss with FACRI (N-2)**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in overloads of Springer – Gladstone 115 kV line. Springer – Gladstone is a known problem for which remediation is already planned.

6.5.3. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-5. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions). While it would appear that the Level C (N-2) contingencies do not meet Idaho's reactive margin requirements, a review of the margin tables shows the lowest margins for contingencies C03 & C04. Follow-up RAS scenarios fully resolve margin deficiencies noted by red shaded cells.

6.5.4. Transient Stability Analysis

As shown on Appendix 4-5, dynamic simulations were run on both nomogram corner points. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. However, these deviations are within the “exceptions” for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

Contingency B16 (Aeolus – Mona Annex 500 kV line) also produced voltage deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

6.6. Bridger / Anticline West vs. Bonanza West

6.6.1. Base Case Development

The Gateway West Project base case was modified to stress Bridger / Anticline West to 4100 MW with several cases spanning a range of Bonanza West flows. The primary resource for stressing Bridger / Anticline West was the Wyoming Wind developments. Bonanza West flows were controlled by varying; 1) Bonanza generation, 2) Craig / Hayden generation, 3) Currant Creek generation, and 4) IPP DC flows and the wind generation connected to IPP 345.

For cases with Aeolus South flows at 1700 MW, Bridger / Anticline West flows were fine tuned by varying schedules from WAPA (73) to the Northwest (40). Shunt capacitors were added to Mona Annex 500 kV to support the high flows into central Utah. Path flows for each of the above cases are shown on Appendix 3-6. The resulting nomogram is shown on Appendix 2-6.

Finally, two margin test cases were developed with 5% additional flows across 1) Aeolus West path and 2) Bonanza West path. These cases are shown near the bottom of Appendix 3-6.

6.6.2. Post-Transient Analysis

Appendix 3-6 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) becomes the limiting contingency for both nomogram corners. For both nomogram corner points, this outage results in overloads of the Miners – Platte 230 kV line, and this loading sets the PT limit.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. Some voltage deviation problems are noted, but these issues are fully mitigated with RAS switching.

- **Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)**

This outage resulted on overloads of the Bridger – Rock Springs 230kV line. Follow-up cases with Bridger generation dropping and additional RAS action on Path 18 resolve both the loading problem and the voltage deviation issues on Path 18.

- **Palo Verde 2-unit loss with FACRI (N-2)**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in overloads of Springer – Gladstone 115 kV line. Springer – Gladstone is a known problem for which remediation is already planned.

6.6.3. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-6. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.6.4. Transient Stability Analysis

As shown on Appendix 4-6, dynamic simulations were run on both nomogram corner points. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. However, these deviations are within the "exceptions" for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

Contingency B16 (Aeolus – Mona Annex (Clover) 500 kV line) resulted in no voltage or frequency deviations for the upper left nomogram point (695, 4100). The lower right nomogram corner point (785, 4062) had extensive difficulties with an over-excitation limiter (OEL1) model that tripped the unit supposedly to protect the rotor from overheating damage. Flows on Bonanza
West were decremented down to 3532 MW before the OEL1 generation trip problem was resolved. After a discussion of these results, Deseret provided corrected OEL1 model data that slightly changed the timing of the trips, but not the end result. Additional sensitivity cases with the OEL1 trip timers set to 999 seconds but with the OEL1 runback function still active, the PT corner point (785, 4062) had no voltage or frequency deviations and of course the unit does not trip.

6.7. Bridger / Anticline West vs. Idaho – Montana (Path 18)

6.7.1. Base Case Development

The Gateway West Project base case was modified to stress Bridger / Anticline West to 4100 MW and Path 18 was controlled to 337 MW. The primary resource for stressing Bridger / Anticline West was the Wyoming Wind developments with fine tuning using schedules from WAPA (73) to Northwest (40). Path 18 flows were controlled by schedules from Montana (62) to Idaho (60) and adjustments of the Jefferson and Mill Creek phase shifters.

Two margin test cases were developed with 5% additional flows across 1) Bridger / Anticline West and 2) Path 18. These cases are shown near the bottom of Appendix 3-7.

6.7.2. Post-Transient Analysis

Appendix 3-7 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **Bridger – 3 Mile Knoll 345 kV Line (Contingency B04 and RAS variations)**

  This outage results in voltage deviations and violations of the .87 pu voltage standard for the Path 18 buses. Follow-up cases were run with switching of the Kinport 345 kV shunt capacitor, Dillon 69 kV shunt capacitors c3 & c4, and a new 42 MVar shunt capacitor at Big Grassy 161 kV. These cases show the voltage problem resolved with the lowest voltage shown to be .881 pu at Peterson Flat 230. The overload shown for E.Helena 69/100 kV #2 is the result of circulating reactive power (vars) between the two transformers at E.Helena. If the transformers were correctly modeled, the overload would be resolved.

- **3 Mile Knoll –Goshen 345 kV Line (Contingency B06 and RAS variations)**

Contingency B06 results in overloads on the Grace – Soda 138 kV line. The follow-up case B06a, with the 3 Mile Knoll series capacitor bank bypassed, results in a violation of Montana's .90 pu voltage standard. A second follow-up case (B06b), with switching of the Big Grassy 161 kV shunt capacitor fully resolves the voltage problem.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) fully resolves all voltage and loading problems.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. In follow-up cases, some voltage deviation problems are noted, but these issues are fully mitigated with RAS switching.

- **Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)**

This outage resulted in voltage deviations on Path 18 buses. Follow-up cases with RAS switching of Path 18 shunt capacitors and load tripping via under-voltage relays results in acceptable performance.

- **Palo Verde 2-unit loss with FACRI (N-2)**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in overloads of several overloads including the Sigurd PS – Glen Canyon 230kV line. This line is loaded southbound in the base case, and this loading result may indicate a simultaneous flow relationship between Bridger / Anticline West and Tot 2B.

6.7.3. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-7. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies.

Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions). While it would appear that the Level C (N-2) contingencies do not meet Idaho's reactive margin requirements, a review of the margin tables shows the lowest margins for contingencies C03 & C04. Follow-up RAS scenarios fully resolve any margin deficiencies.

6.7.4. Transient Stability Analysis

As shown on Appendix 4-7, dynamic simulations were run on the simultaneous flow corner point. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. However, these deviations are within the exceptions for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the post-transient contingencies.

6.8. Bridger / Anticline West vs. Monument – Naughton

6.8.1. Base Case Development

The Gateway West Project base case was modified to stress Bridger / Anticline West to 4100 MW with several cases spanning a range of Monument – Naughton flows from 332 MW to 475 MW. The primary resource for stressing Bridger / Anticline West was the Wyoming Wind developments. Monument – Naughton flows were controlled by the Monument phase shifting transformers. Loads in the Trona area of SW Wyoming (Zone 668) were reduced by roughly 141 MW to prevent the Rock Springs / Firehole cut-plane from exceeding its 640 MW capacity. The resulting nomogram is shown on Appendix 2-8.

Two margin test cases were developed with 5% additional flows across 1) Bridger / Anticline West and 2) Monument - Naughton. These cases are shown near the bottom of Appendix 3-8.

6.8.2. Post-Transient Analysis

Appendix 3-8 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **3 Mile Knoll – Goshen 345 kV Line (Contingencies B06 and B06a)**

Contingency B06 results in overloads on the Grace – Soda 138 kV line. The follow-up case B06a, with the 3 Mile Knoll series capacitor bank bypassed, fully resolves the overload.

- **<u>Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)</u>**

This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) resolves the voltage deviation problems. This outage results in a slight overload (100.04%) on the Miners – Platte 230 kV line even with the 521 MVA 30 minute emergency rating, and thereby sets the PT limit for this contingency.

- **<u>Aeolus – Mona Annex (Clover) 500 kV Line (Contingency B36 and RAS variations)</u>**

This contingency also diverges without any RAS actions. With 600 MW of generation dropping and 500 kV and 230 kV switchable capacitor applications, the contingency converges to a solution with no overloads.

- **<u>Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)</u>**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. Some voltage deviation problems are noted, but these issues are fully mitigated with RAS switching.

- **<u>Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)</u>**

This outage resulted in a voltage deviation at Populus 500 for the case with Bridger / Anticline West at 4100 MW. Follow-up RAS cases with Bridger gen tripping resolve the Populus deviation problem, but then created problems for Path 18 buses. The case with 475 MW on Monument - Naughton, this outage overloaded both Monument phase shifters. While RAS actions did help the loading situation, a better solution would be to adjust the phase shifter taps to reduce flows.

- **<u>Palo Verde 2-unit loss with FACRI (N-2)</u>**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in an overload of the Glen Canyon 345 / 230 kV transformer. This overload arises when the generation at Glen Canyon is not correctly divided between the 230 kV and 345 kV step-up buses. This is a known modeling problem and is unrelated to the Gateway West Project.

6.8.3. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-8. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.8.4. Transient Stability Analysis

As shown on Appendix 4-5, dynamic simulations were run on both nomogram corner points. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. However, these deviations are within the exceptions for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

6.9. Bridger / Anticline West vs. Rock Springs / Firehole

The Gateway West Project base case was modified to stress Bridger / Anticline West to 4100 MW with several cases spanning a range of Rock Springs / Firehole (RS/FH) West flows from 489 MW to 640 MW. The primary resource for stressing Bridger / Anticline West was the Wyoming Wind developments. RS/FH flows were controlled by adjustments to the Monument phase shifting transformers. The resulting nomogram is shown on Appendix 2-9.

Two margin test cases were developed with 5% additional flows across 1) Bridger / Anticline West and 2) RS/FH West. These cases are shown near the bottom of Appendix 3-9.

6.9.1. Post-Transient Analysis

Appendix 3-9 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **3 Mile Knoll – Goshen 345 kV Line (Contingencies B06 and B06a)**

Contingency B06 results in overloads on the Grace – Soda 138 kV line. The follow-up case B06a, with the 3 Mile Knoll series capacitor bank bypassed, fully resolves the overload.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) resolves the voltage deviation problems. This outage results in a slight overload (100.05%) on the Miners – Platte 230 kV line even with the 521 MVA 30 minute emergency rating, and thereby sets the PT limit for this contingency.

- **Aeolus – Mona Annex (Clover) 500 kV Line (Contingency B36 and RAS variations)**

This contingency also diverges without any RAS actions. With 600 MW of generation dropping and 500 kV and 230 kV switchable capacitor applications, the contingency converges to a solution with no overloads.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. Some voltage deviation problems are noted, but these issues are fully mitigated with RAS switching.

- **Palo Verde 2-unit loss with FACRI (N-2)**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in an overload of the Glen Canyon 345 / 230 kV transformer. This overload arises when the generation at Glen Canyon is not correctly divided between the 230 kV and 345 kV step-up buses. This is a known modeling problem and is unrelated to the Gateway West Project.

6.9.2. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-9. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.9.3. Transient Stability Analysis

As shown on Appendix 4-5, dynamic simulations were run on both nomogram corner points. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. However, these deviations are within the exceptions for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

6.10. Bridger / Anticline West with the MSTI Project

6.10.1. Base Case Development

The Gateway West Project base case was modified to stress Bridger / Anticline West to 4100 MW simultaneous with the MSTI project at 1496 MW. Resources for the majority of the schedules were from three 450 MW equivalent wind models represented near Townsend, Montana. To fully load the MSTI project, other Montana generation was increased and scheduled to Idaho and the Northwest.

Two margin test cases were developed with 5% additional flows across 1) Bridger / Anticline West and 2) The MSTI project. These cases are shown near the bottom of Appendix 3-10. The resulting nomogram is shown on Appendix 2-10.

6.10.2. Post-Transient Analysis

Appendix 3-10 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **<u>Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)</u>**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **<u>Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)</u>**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **<u>Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)</u>**

This contingency diverges without any RAS actions. However with RAS actions as noted for the B35g, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied, additional 230kV capacitors at Mustang, Riverton, and additional capacitors on Path 18) does not quite resolve the voltage deviation problems until Path 18 is reduced to 287 MW.

- **<u>Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)</u>**

This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. However, as noted above, the loading numbers are to be used as a design input for rebuilding the limiting conductor sections. The Bridger – Rock Spring 230 kV line is also overloaded. But this loading and the voltage deviation problems are mitigated with RAS switching.

- **<u>Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)</u>**

This outage resulted in an overload of the Bridger – Rock Springs 230kV line. Follow-up cases with Bridger generation dropping and additional RAS action on Path 18 resolved both the loading problem and the voltage deviation issues on Path 18.

- **<u>Palo Verde 2-unit loss with FACRI (N-2)</u>**

This contingency, with FACRI action and Desert SW load dropping planned for this event resulted in overloads of Springer – Gladstone 115 kV line. Springer – Gladstone is a known problem for which remediation is already planned. This contingency also had 7 voltage deviations in the New Mexico system.

6.10.3. Reactive Margin Analysis

Margin cases from the point with simultaneous flows on Bridger / Anticline West and the MSTI Project were tested with +5% flow cases as noted near the bottom of Appendix 3-10. Both +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.10.4. Transient Stability Analysis

As shown on Appendix 4-9, dynamic simulations were run on the one simultaneous case. Contingency B08 and B09 with RAS variations, resulted in back swing under-frequency deviations. However, these deviations are within the exceptions for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage and frequency deviations. However, these were mitigated with some of the RAS actions simulated in the PT contingencies.

6.11. Path C Southbound vs. Idaho – Montana (Path 18)

6.11.1. Base Case Development

The Gateway West Project base case was modified to stress Path C North to South flows to 2250 MW simultaneous with stressed Path 18 North to South flows. Two base cases were developed. The first case included Path 18 Shunt Additions while the second case did not. Without the Path 18 Shunt Additions, Path 18 North to South flows were limited to 285 MW. With the Path 18 Shunt Additions, Path 18 North to South flows were limited to the current Path 18 transfer limit of 337 MW. The Path 18 Shunt Additions include switchable capacitor banks at the Amps, Peterson Flat, Big Grassy, and Dillon stations.

Multiple margin test cases were developed with 5% additional flows across Path C and Path 18. These cases are shown near the bottom of Appendix 3-11.

The resulting nomogram is shown on Appendix 2-10.

6.11.2. Post-Transient Analysis

Appendix 3-10 contains the tables associated with the post-transient study results for the import cases with and without Path 18 Shunt Additions. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  When applied to the case without the Path 18 Shunt Additions, this outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West

Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

When Contingency B01 was applied to the case with the Path 18 Shunt Additions, this outage didn't result in any overloads or voltage issues.

- **3 Mile Knoll - Goshen 345kV Line (Contingency B06 and RAS variations)**

In both cases (with and without the Path 18 Shunt Additions), this outage without RAS resulted in overloads of the Grace – Soda and 3 Mile Knoll – Soda 138 kV lines. Bypassing the 1/2 the series capacitor in the Bridger - 3 Mile Knoll 345kV line mitigates both of these overloads.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

In the case without the Path 18 Shunt Additions, this outage resulted in overloads on the Dave Johnston - Dave Johnston South Tap 115 kV line and the Bridger 345/230kV Bank #2. In the case with the Path 18 Shunt Additions, this outage resulted in overloads on the Dave Johnston - Dave Johnston South Tap 115 kV line only. In both cases, the RAS actions as noted for disturbance B35a (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied at Aeolus, and additional 230kV capacitors applied at Aeolus, Atlantic, Miners and Platt) resolved these overloads.

- **Aeolus – Mona Annex (Clover) 500 kV Line (Contingency B36 and RAS variations)**

In both cases (with and without the Path 18 Shunt Additions), this disturbance without any RAS actions caused the cases to diverge. With 600 MW of generation dropping and 500 kV and 230 kV switchable capacitor applications, the contingency problems are fully resolved.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

In both cases (with and without the Path 18 Shunt Additions), this disturbance without any RAS actions caused overloads on the Bridger – 3 Mile Knoll 345 kV and Grace - Soda 138kV lines. RAS action, as noted for disturbance C02a (Tripping of a Bridger Unit), resolved these overloads.

- **Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)**

In the case without the Path 18 Shunt Additions, this disturbance was limiting for Path 18 flows. Outage C03 caused the voltage at the PTRSNFUR 69kV bus to drop to 0.90 pu. Increasing Path 18 flows to levels greater than 285MW North to South caused post-contingency voltages at the PTRSNFUR 69kV bus to drop below 0.90 pu. In addition, the RAS variations of disturbance C03, including C03a and C03b (dropping one or two Bridger units), caused the post-contingency voltages at the PTRSNFUR 69kV bus to be worse. Since disturbances C03d and C03e both include Path 18 shunts addition switching, they were not applied to the case.

Without the Path 18 Shunt Additions, this outage limited Path 18 flows to 285 MW North to South. With the Path 18 Shunt Additions and their employment in outage C03d and C03e, Path 18's transfer limit is maintained at 337 MW North to South.

- **Populus - Ben Lomond 345 kV #2 and #3 Double Line Outage (C06 and RAS variations)**

In both cases (with and without the Path 18 Shunt Additions), this outage resulted in an overload of the Grace – Soda 138 kV line. In the case with Path 18 shunts, this outage also resulted in an overload of the 3 Mile Knoll – Soda 138 kV line. Bypassing the 1/2 the series capacitor in the Bridger - 3 Mile Knoll 345kV line mitigates these overloads.

- **Populus – Terminal 345 kV + Treasureton – Brady 230 kV Lines Outage (C12)**

In the case without the Path 18 Shunt Additions, this outage resulted in an overload of the Grace – Soda 138 kV line. Bypassing the 1/2 the series capacitor in the Bridger - 3 Mile Knoll 345kV line mitigates both of these overloads. In the case with the Path 18 Shunt Additions, no emergency overloads were encountered.

6.11.3. Reactive Margin Analysis

From the base cases, margin cases (with and without Path 18 Shunt Additions) were created. The margin cases stressed Path 18 North to South and Path C North to South flows by an additional +5% as noted near the bottom of Appendix 3-11. All +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho’s reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.11.4. Transient Stability Analysis

As shown on Appendix 4-11, dynamic simulations were run on the simultaneous cases (with and without Path 18 Shunt Additions). Contingency B09 resulted in back swing under-frequency deviations that exceed the standard WECC frequency deviation criteria for load buses, but did not exceed PacifiCorp's frequency deviation exception for Bridger unit buses on file with WECC. All the other disturbances modeled did not result in transient stability problems or criteria violations.

6.12. Path C Southbound vs. Bonanza West

6.12.1. Base Case Development

The Gateway West Project base case was modified to stress Path C North to South flows simultaneous with stressed Bonanza West (Path 33) flows. Two base cases were developed. The first case included Path C set at 2250 MW North to South with Bonanza West simultaneously set at 749 MW. The second case included Path C set at 1849 MW North to South with Bonanza West simultaneously set at 785 MW, Path 33's current transfer limit.

Multiple margin test cases were developed with 5% additional flows across Path C and Bonanza West. These cases are shown near the bottom of Appendix 3-12.

The resulting nomogram is shown on Appendix 2-11.

6.12.2. Post-Transient Analysis

Appendix 3-12 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  This outage results in overloads on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **3 Mile Knoll - Goshen 345kV Line (Contingency B06 and RAS variations)**

  In both cases, this outage without RAS resulted in overloads of the Grace – Soda and 3 Mile Knoll – Soda 138 kV lines. Bypassing the 1/2 the series capacitor in the Bridger - 3 Mile Knoll 345kV line mitigates the loading on the 3 Mile Knoll – Soda 138 kV line entirely. However, bypassing the 1/2 the series capacitor in the Bridger - 3 Mile Knoll 345kV line mitigates the loading on the Grace – Soda 138 kV line to approximately 101% of its emergency rating.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

  In the case with Path C stressed at 2250 MW North to South and Bonanza West at 749 MW, this outage resulted in overloads on the Platt - Latham and Miners - Platt 230kV lines as well as voltage deviations greater than 5% on many buses. The RAS actions as noted for disturbance B35a, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied at Aeolus, and additional 230kV capacitors applied at Aeolus, Atlantic, Miners and Platt) resolved these overloads and voltage deviations.

  In the case with Bonanza West stressed at 785 MW and Path C at 1849 MW North to South, this outage resulted in the following: overloads on all three Bridger 345/230 kV banks, the Platt - Latham 230kV line, Miners - Platt 230kV line and Bar X-Echo Springs 230kV line; voltage deviations greater than 5% on many buses; and post-contingency voltages in Wyoming lower than 0.9 pu. The RAS actions, as noted for disturbance B35a, were enough to mitigate the emergency overloads; however, they were not enough to mitigate the bus voltage deviations. The RAS actions as noted for disturbance B35d (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied at Aeolus, and additional 230kV capacitors applied at Aeolus, Atlantic, Miners, Platt, Mustang and Riverton) resolved the remaining voltage deviations.

- **Aeolus – Mona Annex (Clover) 500 kV Line (Contingency B36 and RAS variations)**

This disturbance without any RAS measures caused both cases to diverge. With 600 MW of generation dropping and 500 kV and 230 kV switchable capacitor applications (outage B36a), the cases exhibited enough reactive margin to solve.

In the case with Path C stressed at 2250 MW North to South and Bonanza West at 749 MW, an overload on the Grace – Soda 138 kV line still remained even with the RAS actions employed for disturbance B36a. The additional RAS measure of bypassing the 1/2 the series capacitor in the Bridger - 3 Mile Knoll 345kV line mitigated the Grace – Soda 138 kV line overload.

In the case with Bonanza West stressed at 785 MW and Path C at 1849 MW North to South, the RAS actions as noted for B36a were sufficient to mitigate all emergency overloads and voltage deviations.

- **Bonanza –Mona 345kV Line (Contingency B40 and RAS variations)**

In the case with Path C stressed at 2250 MW North to South and Bonanza West at 749 MW, this outage resulted in overloads on the Emma Park - Upalco, Emma Park - Panther and Panther - Carbon 138kV lines as well as voltage deviations greater than 5% on a few buses near Upalco. In the case with Bonanza West stressed at 785 MW and Path C at 1849 MW North to South, this outage resulted in overloads on the Emma Park - Upalco, Emma Park - Panther and Panther - Carbon, Bonanza-Vernal 138kV lines as well as the Flaming Gorge 230/138 kV bank #2. This outage also resulted in voltage deviations greater than 5% on a few buses near Upalco. The RAS actions as noted for disturbance B40a, (Tripping a Bonanza Unit) resolved these overloads and voltage deviations. In both cases, Path C and Bonanza West flows were limited by disturbance C04a with RAS tripping of a Bonanza unit and the subsequent overload of the Emma Park - Upalco 138kV line.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

In both cases, this disturbance without any RAS actions caused overloads on the Bridger – 3 Mile Knoll 345 kV and Grace - Soda 138kV lines. RAS action, as noted for disturbance C02a (Tripping of a Bridger Unit), resolved the Grace - Soda 138kV line overloads. The Bridger - 3 Mile Knoll 345kV line remained overloaded in both cases. Tripping two Bridger units will mitigate the loading on the Bridger - 3 Mile Knoll 345kV line; however, the voltage drop around Path 18 starts to become an issue in the case with Path C stressed at 2250 MW North to South and Bonanza West at 749 MW. After the tripping two units, the post-contingency bus voltage at the PTRSNFUR 69.0 bus was 0.899 pu, which is right at the limit of 0.9 pu.

- **Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)**

Disturbance C03 without any RAS actions caused the case with Path C at 2250 MW North to South and Bonanza West at 749 MW to diverge. Conversely, the case with Bonanza West at 785 MW and Path C at 1849 MW North to South solved following disturbance C03. Both cases solved following C03a (C03 plus RAS Tripping of one Bridger Unit) and C03b (C03 plus RAS Tripping of two Bridger Unit); however, the RAS tripping of the Bridger units following disturbance C03 caused the voltage at the PTRSNFUR 69kV bus to get worse (less than 0.9 pu). Both cases solved following disturbance C03d (C03 plus RAS Tripping of one Bridger unit plus RAS switching of capacitors at Amps and Big Grassy stations) exhibited acceptable voltages in Wyoming and near Path 18. The Amps and Big Grassy capacitors switched as part of the remedial action for disturbance C03 are part of the Path 18 Shunt Additions.

- **Populus - Ben Lomond 345 kV #2 and #3 Double Line Outage (C06 and RAS variations)**

In the case with Path C at 2250 MW North to South and Bonanza West at 749 MW, this outage resulted in an overload of the Grace – Soda 138 kV line. Bypassing the 1/2 the series capacitor in the Bridger - 3 Mile Knoll 345kV line mitigates this overload.

- **Palo Verde 2-unit loss with FACRI (N-2)**

This contingency, with FACRI action and Desert SW load dropping planned for this event, resulted in overloads of Springer – Gladstone 115 kV line. Springer – Gladstone is a known problem for which remediation is already planned.

6.12.3. Reactive Margin Analysis

From the base cases, margin cases were created. The margin cases stressed Bonanza West and Path C North to South flows by an additional +5% as noted near the bottom of Appendix 3-12. All +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.12.4. Transient Stability Analysis

As shown on Appendix 4-12, dynamic simulations were run on the simultaneous cases. Contingency B08 and B09 resulted in back swing under-frequency deviations that exceed the standard WECC frequency deviation criteria for load buses, but did not exceed PacifiCorp's frequency deviation exception for Bridger unit buses on file with WECC.

In the case with Path C at 2250 MW North to South and Bonanza West at 749 MW, all the other disturbances modeled did not result in transient stability problems or criteria violations.

In the case with Bonanza West at 785 MW and Path C at 1849 MW North to South, disturbances B15 (Aeolus – Anticline 500 kV Line) and B16 (Aeolus – Mona Annex (Clover) 500 kV Line) caused voltage dips exceeding 20% for 20 cycles or more at multiple load buses. Disturbances B15a and B16a with RAS (tripping 600 MW of Aeolus units and insertion of capacitors at the Aeolus 500kV bus and at the Aeolus, Miners, Platt and Atlantic 230kV buses) mitigated the voltage dips noted.

6.13. Path C Southbound with the MSTI Project

6.13.1. Base Case Development

The Gateway West Project base case was modified by the addition of the MSTI project. The case was further modified by stressing Path C North to South flows simultaneous with MSTI Project flows. One base case was developed with Path C set at 2250 MW North to South and MSTI Phase Shifter flow simultaneously set at 1500 MW. To achieve a Phase Shifter flow of 1500 MW, it was necessary to dispatch 800 MW of total MSTI generation

Multiple margin test cases were developed with 5% additional flows across Path C and the MSTI Phase Shifter. These cases are shown near the bottom of Appendix 3-13.

The resulting nomogram is shown on Appendix 2-12.

6.13.2. Post-Transient Analysis

Appendix 3-13 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **Anticline – Populus 500 kV Line (Contingency B01 and RAS variations)**

  This outage results in an overload on the Bridger – 3 Mile Knoll 345 kV line. In the cases, the line is rated at 1840 Amps and this loading information has been requested for design input to PacifiCorp to determine the magnitude of rating increase needed to rebuild the single conductor portions of the line capable of withstanding the most severe contingencies imposed by the Gateway West Project. Several RAS options are shown to allow selection of line upgrade costs vs. the risks inherent with RAS.

- **3 Mile Knoll - Goshen 345kV Line (Contingency B06 and RAS variations)**

  This outage without RAS resulted in overloads of the Grace – Soda and 3 Mile Knoll – Soda 138 kV lines. Bypassing the 1/2 the series capacitor in the Bridger - 3 Mile Knoll 345kV line mitigates both of these overloads.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

This outage resulted in voltage deviations greater than 5% on many buses. The RAS actions, as noted for disturbance B35a (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied at Aeolus, and additional 230kV capacitors applied at Aeolus, Atlantic, Miners and Platt), resolved the voltage deviations.

- **Bonanza –Mona 345kV Line (Contingency B40 and RAS variations)**

This outage resulted in overloads on the Emma Park - Upalco, Emma Park - Panther and Panther - Carbon 138kV lines. The RAS actions, as noted for disturbance B40a (Tripping a Bonanza Unit), resolved these overloads.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

This disturbance without any RAS actions caused overloads on the Bridger – 3 Mile Knoll 345 kV and Grace - Soda 138kV lines. RAS action, as noted for disturbance C02a (Tripping of one Bridger Unit), resolved the Grace - Soda 138kV line overload. The Bridger - 3 Mile Knoll 345kV line remained slightly overloaded. Tripping of two Bridger units, as modeled in disturbance C02b, resolved both overloads.

- **Populus - Ben Lomond 345 kV #2 and #3 Double Line Outage (C06 and RAS variations)**

This outage resulted in an overload of the Grace – Soda 138 kV line. Bypassing the 1/2 the series capacitor in the Bridger - 3 Mile Knoll 345kV line mitigates this overload.

- **Palo Verde 2-unit loss with FACRI (N-2)**

This contingency, with FACRI action and Desert SW load dropping planned for this event, resulted in overloads of Springer – Gladstone 115 kV line. Springer – Gladstone is a known problem for which remediation is already planned.

6.13.3. Reactive Margin Analysis

From the base cases, margin cases were created. The margin cases stressed MSTI and Path C North to South flows by an additional +5% as noted near the bottom of Appendix 3-13. All +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.13.4. Transient Stability Analysis

As shown on Appendix 4-12, dynamic simulations were run on the simultaneous cases. Contingency B09 resulted in back swing under-frequency deviations that exceed the standard

WECC frequency deviation criteria for load buses, but did not exceed PacifiCorp's frequency deviation exception for Bridger unit buses on file with WECC.

6.14. Path C Southbound vs. Monument – Naughton

6.14.1. Base Case Development

The Gateway West Project base case was modified to stress Path C Southbound to 2250 MW with Monument – Naughton flows at 475 MW. Path C was stressed by reducing generation in Utah and increasing generation in the Pacific Northwest. Monument – Naughton flows were controlled by the Monument phase shifting transformers. Loads in the Trona area of SW Wyoming (Zone 668) were reduced by roughly 356 MW to prevent normal overloads of the Rock Springs - Palisades 230kV Line. The resulting nomogram is shown on Appendix 2-13.

Two margin test cases were developed with 5% additional flows across 1) Path C Southbound and 2) Monument - Naughton. These cases are shown near the bottom of Appendix 3-14.

6.14.2. Post-Transient Analysis

Appendix 3-14 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **<u>3 Mile Knoll – Goshen 345 kV Line (Contingencies B06 and B06a)</u>**

  Contingency B06 results in an overload on the Grace – Soda 138 kV line. The RAS modeled in outage B06a, which included bypassing 1/2 of the 3 Mile Knoll series capacitor bank, resolved the overload.

- **<u>Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)</u>**

  Contingency B35 diverged without any RAS actions. The RAS actions, as noted for the B35d (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied at Aeolus and additional 230kV capacitors at Aeolus, Atlantic, Miners, Platt, Mustang, and Riverton), resolved the voltage deviation problems.

- **<u>Aeolus – Mona Annex (Clover) 500 kV Line (Contingency B36 and RAS variations)</u>**

  Contingency B36 diverged without any RAS actions. The RAS actions, as noted for the B36v (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied at Aeolus, Anticlin, Populus, additional 230kV capacitors at Aeolus, Atlantic, Miners, Platt, Mustang, Riverton and Chappel, as well as one 345kV capacitor at Kinport), resolved the divergence and didn't produce any WECC criteria violations.

- **<u>Bonanza –Mona 345kV Line (Contingency B40 and RAS variations)</u>**

Outage B40 resulted in overloads on the Bonanza - Vernal, Emma Park - Upalco, Emma Park - Panther and Panther - Carbon 138kV lines, Flaming Gorge 230/138kV Transformer #2 as well as voltage deviations greater than 5% on a few buses near Upalco. The RAS actions, as noted for contingency B40a (Tripping a Bonanza Unit), resolved these overloads and voltage deviations.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

Outage C02 resulted in an overload on the Bridger – 3 Mile Knoll 345 kV line. As noted above, the loading numbers will be used as a design input for rebuilding the limiting conductor sections. The overload was fully mitigated with RAS switching of one Bridger unit as modeled in outage C02a.

- **Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)**

Outage C03 resulted in an overload on the Bridger-Rock Springs 230kV line and a low voltage on a single bus (PTRSNFUR 69.0) near Path 18. RAS actions, as noted for the C03d (Tripping of Bridger unit and additional switchable capacitors applied at Big Grassy 161 kV and Amps 230kV buses), resolved the overload and low voltage problems.

6.14.3. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-14. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.14.4. Transient Stability Analysis

As shown on Appendix 4-14, dynamic simulations were run for various contingencies. Contingency B08 and B09 with RAS variations resulted in back swing under-frequency deviations; however, these deviations are within the exceptions for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage deviations, which were mitigated with some of the RAS actions simulated in the PT contingencies.

6.15. Path C Southbound vs. Rock Springs - Firehole

6.15.1. Base Case Development

The Gateway West Project base case was modified to stress Path C Southbound to 2250 MW with Rock Springs / Firehole West flows at 640 MW. Path C was stressed by reducing generation in Utah and increasing generation in the Pacific Northwest. Rock Springs / Firehole

West flows were controlled by the Monument phase shifting transformers. The resulting nomogram is shown on Appendix 2-14.

Two margin test cases were developed with 5% additional flows across 1) Path C Southbound and 2) Rock Springs / Firehole West. These cases are shown near the bottom of Appendix 3-15.

6.15.2. Post-Transient Analysis

Appendix 3-15 contains the tables associated with the post-transient study results for the import cases. A discussion of several of the prominent outages follows.

- **3 Mile Knoll – Goshen 345 kV Line (Contingencies B06 and B06a)**

  Contingency B06 results in an overload on the Grace – Soda 138 kV line. The RAS modeled in outage B06a, which included bypassing 1/2 of the 3 Mile Knoll series capacitor bank, resolved the overload.

- **Aeolus – Anticline 500 kV Line (Contingency B35 and RAS variations)**

  Contingency B35 without any RAS actions produced several voltage deviations greater than 5%, low voltages in Wyoming and various emergency overloads. The worst emergency overload occurred on the Platt - Latham 230kV line at 111%., and the worst voltage deviation (17.4%) occurred at the Latham 34.5kV bus. Correspondingly, the lowest voltage (0.838 pu) was experienced occurred at the Bairoil 115kV bus. The RAS actions, as noted for the B35d, (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied at Aeolus and additional 230kV capacitors at Aeolus, Atlantic, Miners, Platt, Mustang, and Riverton) resolved all the voltage deviations, low voltages and emergency overloads.

- **Aeolus – Mona Annex (Clover) 500 kV Line (Contingency B36 and RAS variations)**

  Contingency B36 diverged without any RAS actions. The RAS actions, as noted for the B36v (600 MW of Aeolus area generation dropping, 500 kV switchable capacitors applied at Aeolus, Anticlin, Populus, additional 230kV capacitors at Aeolus, Atlantic, Miners, Platt, Mustang, Riverton and Chappel, as well as one 345kV capacitor at Kinport), resolved the divergence and didn't produce any WECC criteria violations.

- **Bonanza –Mona 345kV Line (Contingency B40 and RAS variations)**

  Outage B40 resulted in overloads on the Bonanza - Vernal, Emma Park - Upalco, Emma Park - Panther and Panther - Carbon 138kV lines, Flaming Gorge 230/138kV Transformer #2 as well as voltage deviations greater than 5% on a few buses near Upalco. The RAS actions as noted for disturbance B40a, (Tripping a Bonanza Unit) resolved these overloads and voltage deviations.

- **Bridger – Populus 345 kV Lines 1 & 2 (C02 and RAS variations)**

Outage C02 resulted in an overload on the Bridger – 3 Mile Knoll 345 kV line. As noted above, the loading numbers will be used as a design input for rebuilding the limiting conductor sections. The overload was fully mitigated with RAS switching of one Bridger unit as modeled in outage C02a.

- **<u>Bridger – Populus & Bridger – 3 Mile Knoll 345 kV Lines (C03 and RAS variations)</u>**

This outage resulted a low voltage on a bus (PTRSNFUR 69.0) near Path 18. RAS actions, as noted for the C03d (Tripping of Bridger unit and additional switchable capacitors applied at Big Grassy 161 kV and Amps 230kV buses), resolved the low voltage problems.

- **<u>Populus – Ben Lomond 345 kV Double Line Outage (Contingencies C06 and C06k)</u>**

Contingency C06 resulted in an overload on the Grace – Soda 138 kV line. Bypassing 1/2 of the 3 Mile Knoll series capacitor as modeled in outage C06k fully resolved the overload.

6.15.3. Reactive Margin Analysis

Both corner points of the nomogram were tested with +5% flow cases as noted near the bottom of Appendix 3-15. Both corner +5% cases solved for all contingencies (with appropriate RAS actions), indicating sufficient reactive margins for both Level B and Level C contingencies. Idaho's reactive margin requirements were also met for all contingencies (with appropriate RAS actions).

6.15.4. Transient Stability Analysis

As shown on Appendix 4-15, dynamic simulations were run for various contingencies. Contingency B08 and B09 with RAS variations resulted in back swing under-frequency deviations; however, these deviations are within the exceptions for Bridger that are filed with the WECC. See Appendix 21 for details of the TSS Approved exceptions for Bridger.

Contingency B15 (Aeolus – Anticline 500 kV line) also produced voltage deviations, which were mitigated with some of the RAS actions simulated in the PT contingencies.

7. Contingencies Studied

A list of the studied contingencies are located in Appendix A

8. Study Conclusions / Recommendations

Results of the simultaneous path interaction studies are summarized in Table 2.

Table 2

Primary Path	Secondary Path	Simultaneous Limitations	Max Path Flows		Comments
			Primary	Secondary	
Aeolus West;	Aeolus South Flow	Nomogram	2672	1700	
	Bonanza West	Nomogram	2672	785	
	Tot 1a		2672	650	
Bridger / Anticline West	Aeolus South Flow	Nomogram	4095	1700	Primary Path to be increased to 4100 MW
	Path C Southbound	Nomogram	4100	2250	
	Bonanza West	Nomogram	4100	785	
	Path 18	No Restrictions	4100	337	Path 18 @ 337 Achieved w/ Caps Added
	MSTI Project	No Restrictions	4100	1500	
	Monument-Naughton	Nomogram	4100	475	
	Rock Spgs / Firehole West	Nomogram	4100	640	
Path C Southbound;	Path 18	Nomogram	2250	337	Path 18 @ 337 Achieved w/ Caps Added
	Bonanza West	Nomogram	2250	785	
	MSTI Project	No Restrictions	2250	1500	
	Monument-Naughton	Nomogram			Internal Path - To be added after PRG Review
	Rock Spgs / Firehole West	Nomogram			Internal Path - To be added after PRG Review

Throughout the studies, the Bridger West 345 Path was modeled at 2400 MW with reductions in Bridger / Anticline West flows taken entirely on the Anticline – Populus 500 kV line. Although this path uprate was not specifically requested in the study plan goals, in conjunction with the Gateway West system, a Bridger West 2400 MW rating is proven by this study.

As can be seen from the post-transient results tables, for contingencies involving the Aeolus – Anticline 500 kV and Aeolus – Mona Annex (Clover) 500 kV lines have varying needs for RAS switching to achieve post-transient solutions and acceptable voltage deviations. Details of transfer levels commensurate with RAS generation tripping and capacitor switching will need to be determined in additional studies prior to operation. It is expected that additional studies will need to be developed to determine operating limits as the various components of the Gateway West facilities are energized.

During the course of this study, post-transient voltage deviations and violations of the .90 pu local voltage criteria were noted to be limiting for the most critical contingencies. As a relatively economical expansion of transfer capabilities, some additional shunt capacitors were added as follows;

1. Mona Annex 500; A total of three 200 MVar switchable shunt capacitor banks
2. Anticline 500 kV; A total of three 200 MVar switchable shunt capacitor banks
3. Populus 500 kV; Three 200 MVar switchable shunt capacitor banks
4. Mustang 230 kV; Two 30 MVar Switchable capacitor banks
5. Riverton 230 kV; One 41 MVar Switchable capacitor bank
6. Chapel Creek 230 kV; One 30 MVar Switchable capacitor banks
7. Bonanza 138 kV; One 60 MVar Switchable capacitor bank

Earlier studies of the Bridger / Anticline West vs. Path 18 studies showed a nomogram relationship limited by voltage problems at the Path 18 buses.   After changes to the base case modeling from Northwestern, Idaho Power, and PacifiCorp, revised studies show the modeling changes along with lowering the allowable Path 18 minimum voltage to .87 pu for Level B and Level C contingencies, will allow simultaneous operation at full capacity on each path.   While not demonstrated in these studies, it is expected that these same modeling and voltage standard changes will also impact the Path C southbound vs. Path 18 nomogram such that both paths can be operated at their respective ratings.

Base case overloads noted to be most significant in Appendices 3-5, 3-7, and 3-10. These overloads appear in SE Wyoming and along the Colorado front range and are more prevalent in cases with high loadings on Tot 1a and Bonanza West. In these cases, Tot 3, between SE Wyoming and the "front range" area is some 400 – 600 MW under its current operating limit of 1604 MW.   The Cottonwood – Monument – Kettle Creek 115 kV and Kelker W – Rock Island 115 kV overloads appear to be in the Colorado Springs area and are probably more indicative of a local area problem than anything associated with Gateway West. The Sidney DC tie and the Sidney 230 / 115 transformer overloads appear to be due to scheduling of the Sidney back-to-back DC terminals.

In many of the path flow scenarios studied, overloads of the Grace – Soda 138 kV line, and to a lesser extent, the 3 Mile Knoll – Soda 138 kV line were encountered. These overloads were as a result of Bridger 345 kV system N-1 & N-2 outages and Path C N-2 outages. Tests of several RAS options indicated that bypassing both segments of the 3 Mile Knoll capacitor bank resulted in impacts to system voltages for several 345 kV outages.   Bypassing ½ of the 3 Mile Knoll 345 kV series capacitor bank was the most effective method of mitigating the 138 kV overloads for most conditions while not causing other voltage problems. This assumes that Path 18 recommended voltage mitigations are installed.   With these assumptions, the 3 Mile Knoll – Soda 138 kV line was still slightly overloaded at 101% of its emergency rating and will need to be either uprated, equipped for dynamic ratings, or be rebuilt with higher temperature conductors.

Several scenarios show that for high levels of wind generation and an outage of one of the Aeolus 500 / 230 kV transformers, the remaining two transformers load to about 105% of their emergency ratings.   As these transformers have not yet been specified, it is recommended that the top FOA ratings shown in the base case data be increased to 1764 MVA.

The Bridger – 3 Mile Knoll 345 kV line maximum flows were encountered on the Bridger / Anticline West vs. Path C southbound cases with Contingency C02 and C02a (Bridger - Populus

345kV line DLO). With no gen drop RAS, the maximum line flow was found to be 2354 Amps. If one Bridger Unit is tripped via RAS, then the maximum line flow is 2064 Amps. These flow numbers can be found on Appendix 3-5. With this information, the cost of upgrading the Bridger - 3 Mile Knoll 345 kV line can be compared to continued exposure of the Bridger Units to RAS tripping.

Dynamic stability analysis of Aeolus West vs. Bonanza West and Aeolus West vs. Tot 1a both showed under frequency deviations down to 59.418 Hz. which is outside the TSS Approved exceptions to the NERC/WECC reliability performance standards. Appendix 21 includes the approved exceptions on pages C24 through C26. On page C26, the Bridger 22 kV generator buses are allowed a under frequency deviation down to 59.42 Hz. This exception to the standards may need to be amended to allow for the lower frequency excursion down to 59.40 Hz.

PUBLIC UTILITY COMMISSION OF OREGON

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Cross-Examination Exhibit

Aeolus West Transmission Path Transfer Capability Assessment

Updated Study Report
Revision 2.1

March 30, 2018

Prepared by
PacifiCorp – Transmission Planning

Table of Contents

Updated
Aeolus West Transmission Path
Transfer Capability Assessment

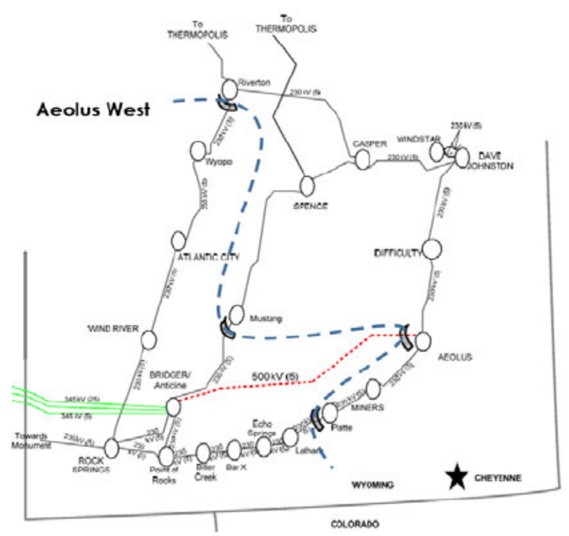
Executive Summary

This assessment was conducted to document the Transfer Capability of the Aeolus West[1] transmission path once the Gateway West – Subsegment D.2[2] (Bridger/Anticline – Aeolus) transmission facilities (D.2 Project) are added to the Wyoming transmission system and assumed resources identified in the PacifiCorp 2017R RFP[3] Shortlist were added.

The Aeolus West transmission path (see Figure 1) is a new path that will be formed by adding the D.2 Project in parallel with the TOT 4A[4] (Path 37) transmission path facilities. The anticipated in-service date for the D.2 Project is October 31, 2020. The D.2 Project is part of PacifiCorp's Energy Vision 2020 (EV2020) initiative which includes the following major transmission facilities and network upgrades to support new wind generation resources:

- Aeolus 500/230 kV substation,
- Shirley Basin – Freezeout 230 kV line loop-in to Aeolus,
- Anticline 500/345 kV substation,
- Aeolus – Anticline 500 kV new line,
- Bridger – Anticline 345 kV new line,
- Shirley Basin – Aeolus 230 kV #1 line rebuild,
- Shirley Basin – Aeolus 230 kV #2 new line,

Figure 1: Aeolus West Transmission Path



[1] The Aeolus West transmission path will include the following major transmission elements: Aeolus* – Anticline 500 kV, Platte* – Latham 230 kV, Mustang* – Bridger 230 kV and Riverton* – Wyopo 230 kV transmission lines. (*meter location)

[2] Gateway West – Subsegment D.2 is a key component of the Energy Vision 2020 (EV2020) initiative that was announced by PacifiCorp on April 4, 2017. Other components of the EV2020 initiative include repowering PacifiCorp's existing wind fleet in southeast Wyoming and adding approximately 1,100 MW of new wind generation east of the Aeolus West transmission path. [Subsequent to the initial announcement, technical studies have demonstrated that as high as 1,510 MW can be integrated east of the Aeolus West transmission path.]

[3] The PacifiCorp 2017R Request for Proposals for renewable resources (2017R RFP) solicited cost-competitive bids for up to 1,270 MW of new or repowered wind energy interconnecting with or delivering to PacifiCorp's Wyoming system with the use of third-party firm transmission service and any additional wind energy located outside of Wyoming capable of delivering energy to PacifiCorp's transmission system that will reduce system costs and provide net benefits for customers.

[4] The existing TOT 4A (Path 37) transmission path is comprised of the Riverton* – Wyopo 230 kV, Platte – Standpipe* 230 kV and Spence* – Mustang 230 kV transmission lines. (*meter location)

- Aeolus – Freezeout 230 kV line reconductor,
- Freezeout – Standpipe 230 kV line reconductor,
- Latham dynamic voltage control device,
- Separate the double-circuit portion of the Ben Lomond - Naughton 230 kV #1 and Ben Lomond - Birch Creek 230 kV #2 lines to create two single-circuit lines,
- Railroad – Croydon 138 kV partial line reconductor,
- Aeolus 230 kV shunt reactor,
- Shirley Basin 230 kV shunt reactor,

The WECC 2021-22 HW power flow base case was utilized for the Aeolus West transfer capability assessment studies. In support of the EV2020 initiative, which calls for the addition of new and repowered wind resources in Wyoming, the base case was modified to achieve the transfer levels evaluated by utilizing PacifiCorp 2017R RFP Shortlist resources as evaluated in the Large Generation Interconnection (LGI) queue, which added 1510 MW east of the Aeolus West "cut plane" and 221 MW in southwest Wyoming. For different Aeolus West transfer levels (heavy and light) and 2400 MW flow across the Jim Bridger West path, resource levels in eastern Wyoming were varied relative to the Jim Bridger Generation in central Wyoming and the Emery/Hunter and Huntington generation in central Utah.

Contingencies that were considered in this analysis include:

- N-1 of D.2 Project facilities
- N-1, N-2 Bridger contingencies
- All eastern, central and northern Wyoming transmission system contingencies performed as part of the TPL-001-4 annual assessment.

For this transfer capability assessment, simultaneous interaction between the Aeolus West path and the TOT 4B path was evaluated; however, the interactions with other transmission paths (Yellowtail South, Jim Bridger West, TOT 1A and TOT 3) were monitored throughout the study. Subsequent transfer capability assessments will evaluate interaction with TOT 3 (Path 36), Bonanza West (Path 33) and TOT 1A (Path 30) transmission paths. (See Appendix A.)

In this revision of the report, the power flow analysis was re-evaluated to identify maximum transfer capability by stressing both the Aeolus West and the TOT 4B paths simultaneously. If required, additional power from Western Area Power Administration (WAPA) was imported into the PacifiCorp East (PACE) balancing authority area.

Conclusions

Technical studies have demonstrated that the interconnected Bulk Electric System (BES) in Wyoming with the D.2 Project added can support the PacifiCorp 2017R RFP Shortlist resources, and that system performance will meet all North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) performance criteria.

Preliminary power flow studies demonstrate that by utilizing existing and planned southeast Wyoming resources[5], the Aeolus West transmission path can transfer up to 1829 MW under simultaneous transfer conditions with the TOT 4B transmission path, effectively[6] increasing the east to west transfer levels across Wyoming by 951 MW. Power flow findings also indicated:

- Dynamic voltage control is necessary at the Latham 230 kV substation to mitigate low voltage conditions resulting from loss of Bridger/Anticline – Aeolus transmission facilities.
- Under certain operating conditions, one Remedial Action Scheme (RAS) will need to be implemented to trip generation following outage of specific transmission facilities in southeast Wyoming.
- The location (and output level) of new and repowered wind resources can influence the transfer capability level across the Aeolus West transmission path and the Aeolus West vs. TOT 4B nomogram curve.

Dynamic stability studies evaluated a wide range of critical system disturbances in eastern Wyoming. The analyses identified two outages with poor voltage performance, and another outage identified a wind turbine modeling problem. These issues are all attributed to the wind turbine models at the Q0706, Q0707 and Q0708 projects. PacifiCorp is working with the wind turbine manufacture to resolve these issues. Aside from these issues, the studied outages evaluated meet the dynamic performance criteria with the system being stable and damped.

[5] Eastern Wyoming Resources: Existing Wind: 1124 MW, Dave Johnston (net) 717 MW; Wyodak (PacifiCorp – net) 268 MW, New Wind – behind the Aeolus West “cut plane”: 1510 MW; east Wyoming: 1270 MW, north Wyoming: 240 MW.

[6] Effective transfers were determined by subtracting the existing TOT 4A path maximum[13] transfer level (960 MW) from the Aeolus West transfer level (1829 MW) and adding the Platte area loads (82 MW) that are up-stream of the Aeolus West metering point.

1 Introduction

1.1 Purpose

The purpose of the study is to demonstrate that the interconnected transmission Bulk Electric System (BES) in Wyoming with the D.2 Project added can support the PacifiCorp 2017R RFP Shortlist resources and can be operated reliably during normal and contingency operations throughout the planning horizon. To achieve this purpose, the study will: (1) identify the new Aeolus West transmission path limitations, (2) evaluate the interactions between the Aeolus West and the TOT 4B transmission paths and develop a nomogram that depicts system limitations, and (3) identify any necessary Remedial Action Schemes (RAS).

This report will summarize the results of the power flow and dynamic stability analysis of the Aeolus West transmission path and will demonstrate that Wyoming transmission system performance with the D.2 project added meets all NERC and WECC performance criteria.

1.2 Plan of Service

The D.2 Project, and supporting network upgrades consists of the following system improvements:

1. Add Aeolus 500/230 kV substation
2. Add Aeolus 500/230 kV, 1600 MVA transformer
3. Loop the Shirley Basin – Freezeout 230 kV line into Aeolus,
4. Add Anticline 500/345 kV substation
5. Add Anticline 500/345 kV, 1600 MVA transformer
6. Add the Aeolus – Anticline 500 kV transmission line, 137.8-miles, 3x1272 ACSR (Bittern) conductor
7. Add the Anticline – Bridger 345 kV line, 5.1-miles, 3x1272 ACSR (Bittern) conductor
8. Add the Aeolus 230 kV, 60 MVAr shunt reactor
9. Add the Shirley Basin 230 kV, 60 MVAr shunt reactor
10. Add Aeolus 500 kV, 200 MVAr shunt capacitor
11. Add Anticline 500 kV, 200 MVAr shunt capacitor
12. Rebuilding of the Aeolus – Shirley Basin 230 kV #1 line, 2x1557 ACSS/TW (Hudson/TW) conductor
13. Add the Aeolus – Shirley Basin 230 kV #2 line, 2x1557 ACSS/TW (Hudson/TW) conductor
14. Reconductor the Aeolus – Freezeout 230 kV line, 2x1272 ACSR (Bittern) conductor

15. Reconductor the Freezeout – Standpipe 230 kV line, 2x1272 ACSR (Bittern) conductor
16. Add dynamic reactive device at Latham 230 kV substation.
17. Separate eight miles of the double-circuit Ben Lomond - Naughton 230 kV #1 and Ben Lomond - Birch Creek 230 kV #2 lines to create two single-circuit lines, and
18. Reconductor 2.35 miles of the Railroad - Croydon 138 kV line, 1222 ACCC high temperature conductor,

1.3 Planned Operating Date

The in-service date for all facilities associated with the D.2 Project is October 31, 2020.

1.4 Scope

The Aeolus West transfer capability assessment assumes the addition of new wind generation facilities as noted in Table 1, which includes the PacifiCorp 2017R RFP Shortlist resources as evaluated in LGI queue studies. While the new technology and model information of the repowered units was used in the steady-state and dynamic stability analysis, no incremental MW output was considered; i.e., each repowered facility was limited to its current LGI agreement generation capacity levels. The study was performed using a 2021-22 heavy winter WECC approved case which was modified to include the D.2 Project facilities. The system model assumed summer line ratings to assess the thermal limitation of the Wyoming system. Load served from Platte is normally represented as an open point between Platte – Whiskey Peak 115 kV. The system configuration with Platte 115 kV normally open is presently the most limiting scenario for the existing TOT 4A/4B nomogram.

2 Study Criteria

2.1 Thermal Loading

For system normal conditions described by the P0[7] event, thermal loading on BES transmission lines and transformers is required to be within continuous ratings.

For contingency conditions described by P1-P7 category planning events, thermal loading on transmission lines and transformers should remain within 30-minute emergency ratings.

[7] Facility outage events that are identified with "P" designations are referenced to the TPL-001-4 NERC standard.

The thermal ratings of PacifiCorp's BES transmission lines and transformers are based on the most recent PacifiCorp's Weak Link Transmission Database and Weak Link Transformer Database.

Table 1: Generating Resources Studied

Existing Wyoming Thermal Generation	Existing East Wyoming Wind Generation	New Wyoming Wind Generation
2396 MW • Dave Johnston (DJ): 717 MW • Wyodak (PacifiCorp): 268 MW • Jim Bridger (PacifiCorp): 1411 MW	1124 MW (Foote Creek, Rock River, High Plains, Seven Mile Hill, Dunlap, Root Creek, Top of the World, Glenrock, Three Buttes, Chevron)	1731 MW • Eastern Wyoming (Aeolus, Shirley Basin, Windstar): 1270 MW • Northern Wyoming (Bighorn Basin): 240 MW • Southwest Wyoming (Uinta County) : 221 MW See Table 4.

2.2 Steady State Voltage Range

The steady state voltage ranges at all PacifiCorp BES buses shall be within acceptable limits as established in PacifiCorp's Engineering Handbook section 1B.3 "Planning Standards for Transmission Voltage[8]" as shown below.

Table 2: Voltage Criteria

Operating System Configuration	Normal Conditions (P0)		Contingency Conditions (P1-P7)	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)
Looped	0.95	1.06[9]	0.90	1.10
Radial	0.90	1.06[9]	0.85	1.10

[8] PacifiCorp Engineering Handbook "Planning Standards for Transmission Voltage," April 8, 2013.

[9] In some situations, voltages may go as high as 1.08 pu at non-load buses, contingent upon equipment rating review.

Steady state voltage ranges at all applicable BES buses on adjacent systems were screened based on the limits established by WECC regional criterion as follows:

- 95% to 105% of nominal for P0 event (system normal),
- 90% to 110% of nominal for P1-P7 events (contingency).

2.3 Post-Transient Voltage Deviation

Post-contingency steady state voltage deviation at each applicable BES load serving bus (having no intermediate connection) shall not exceed 8% for P1 events.

2.4 Dynamic Stability Analysis Criteria

All voltages, frequencies and relative rotor angles are required to be stable and damped. Cascading or uncontrolled separation shall not occur and dynamic voltage response shall be within established limits.

2.5 Dynamic Voltage Response

Dynamic stability voltage response criteria are based on WECC Regional Performance Criteria WR1.3 through WR1.5 as follows:

- Dynamic stability voltage response at the applicable BES buses serving load (having no intermediate connection) shall recover to at least 80% of pre-contingency voltage within 20 seconds of the initiating event for all P1-P7 category events, for each applicable bus serving load.
- For voltage swings following fault clearing and voltage recovery above 80%, voltage dips at each applicable BES bus serving load (having no intermediate buses) shall not dip below 70% of pre-contingency voltage for more than 30 cycles or remain below 80% of pre-contingency voltage for more than two seconds for all P1-P7 category events.
- For contingencies without a fault (P2-1 category event), voltage dips at each applicable BES bus serving load (having no intermediate buses) shall not dip below 70% of pre-contingency voltage for more than 30 cycles or remain below 80% of pre-contingency voltage for more than two seconds.

The following criteria were used to investigate the potential for cascading and uncontrolled islanding:

- Load interruption due to successive line tripping for thermal violations shall be confined to the immediate impacted areas and shall not propagate to other areas. The highest available emergency rating is used to determine the tripping threshold for lines or transformers when evaluating a scenario that may lead to cascading.
- Voltage deficiencies caused by either the initiating event or successive line tripping shall be confined to the immediate impacted areas, and shall not propagate to other areas.

Positive damping in stability analysis is demonstrated by showing that the amplitude of power angle or voltage magnitude oscillations after a minimum of 10 seconds is less than the initial post-contingency amplitude. Oscillations that do not show positive damping within a 30-second time frame shall be deemed unacceptable.

Stability studies shall be performed for planning events to determine whether the BES meets the performance requirements.

- Single contingencies (P1 category events): No generating unit shall pull out of synchronism (excludes generators being disconnected from the system by fault clearing action or by a special protection system).
- Multiple contingencies (P2-P7 category events): When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any transmission system elements other than the generating unit and its directly connected facilities.
- Power oscillations are evaluated by exhibiting acceptable damping. The absence of positive damping within a 30-second time frame is considered un-damped.

3 Base Case Development

3.1 Base Case Selection

The base case development process involves selecting an approved WECC base case, updating the models to represent planned transmission facilities (D.2 Project) and existing and new wind generation (see Table 1) facilities, and then tuning the cases to maximum transfer levels on the WECC transmission path(s) being studied. For this study, the WECC approved base case 2021-22 HW (created on August 19, 2016) was selected. This case meets key criteria in that it is close to the Projects' in-service date of October 31, 2020, includes average load conditions based on 2021 load projections and has an accompanying dynamic stability base case available. This study focused on simultaneous transmission path interaction in the Wyoming area between the Aeolus West and the TOT 4B transmission paths; however, other transmission paths such as Yellowtail South (non-WECC path), Jim Bridger West, TOT 1A and TOT 3 (See Appendix A for path definitions) were monitored throughout the study.

The various critical components for this study purpose selected from the 2021-22 HW base case are listed below:

Table 3: Wyoming Load, Generation and Platte Normal Open Configuration in Base Case

Load or Generation	**Amount (MW)**
North Wyoming PAC Load (including Wyodak load of 42 MW)	391 MW
North Wyoming - WAPA Load	211 MW
Eastern Wyoming PAC Load (including DJ load of 56 MW)	474 MW
Eastern Wyoming PAC Loads on WAPA System	95 MW
Central Wyoming Load (including JB load of 130 MW)	434 MW
Yellowtail South Flow	192 MW
Yellowtail Generation	140/260 MW (Online/Max)
WAPA's Existing Small Generation[10] in North Wyoming	26/50 MW(Online/Max)
WAPA's Existing Small Generation[11] in Eastern Wyoming	484/584 MW(Online/Max)
Wyodak Generation (PacifiCorp/Black Hills)	350/380 MW (Online/Max)
Dry Fork Generation (Basin Electric)	420/440 MW (Online/Max)
Gross Laramie River Generation I (WAPA's swing machine)	605 MW(Max)

[10] WAPA's small generation in north Wyoming includes; Boysen, Buffalo Bill, Heart Mountain, Shoshone, Spring Mountain

[11] WAPA's small generation in eastern Wyoming includes; Alcova, Fremont, Glendo, Guernsy, Kortes, Seminoe, CLR_1, SS_Gen1 AND CPGSTN

Load or Generation	**Amount (MW)**
Gross Laramie River Generation II	590/605 MW(Online/Max)
Gross Dave Johnston (DJ) Generation	700/774 MW(Online/Max)
Total Existing PAC East Wyoming Wind[12] Generation	885.7/1124 MW (Online/Max)
Rapid City DC W Tie	130 w2e (200 MW-bidirectional)
Stegall DC Tie	100 e2w (110 MW-bidirectional)
Sydney DC Tie	196 e2w (200 MW-bidirectional)
TOT 4A Flow	627 MW
TOT 4B Flow	469 MW
Jim Bridger (JB) Generation	2200 MW
Jim Bridger West Flow	2027 MW
TOT 3 Flow	1259.1 MW
TOT 1A Flow	195 MW
Platte – Mustang 115 kV Normal Open Point	Platte – Normal Open

3.2 Generating Facility Additions

The transmission path assessment studies outlined in Section 4 were performed by utilizing the resources identified in Table 4 to evaluate the performance of the Aeolus West transmission path. Transmission and generation projects with an in-service date beyond 2020 were excluded from the analysis. While Table 4 provides the general location of the resources included in the study, Figure 2 provides an overview of PacifiCorp's Wyoming transmission system and provides a visual illustration of the location of each of the existing and new generation (noted in red) resources, and identifies the location of the Aeolus West and TOT 4B transmission path constraints.

[12] PAC eastern Wyoming wind generation includes; Root Creek, Three Buttes, Top of The World, Glenrock, Rolling Hills, Dunlap. Seven Mile Hill, Foote Creek and High Plains wind generation

Table 4: New Wyoming Wind Resources

Proposed New Wind Facilities	LGI Queue Number	Project Size	Point of Interconnection
Northern Wyoming (Bighorn Basin)	Q542	240 MW	Frannie - Yellowtail 230 kV line
Eastern Wyoming (Aeolus/Shirley Basin/Windstar Area)	Q706	250 MW	Aeolus 230 kV
	Q707	250 MW	Shirley Basin 230 kV
	Q708	250 MW	Shirley Basin 230 kV
	Q712	520 MW	Windstar 230 kV
Southwest Wyoming (Uinta County)	Q715	120 MW	Canyon Compression – Railroad 138 kV line
	Q810	101 MW	Canyon Compression – Railroad 138 kV line
TOTAL		**1731 MW**	

3.3 Base Case Modification and Tuning

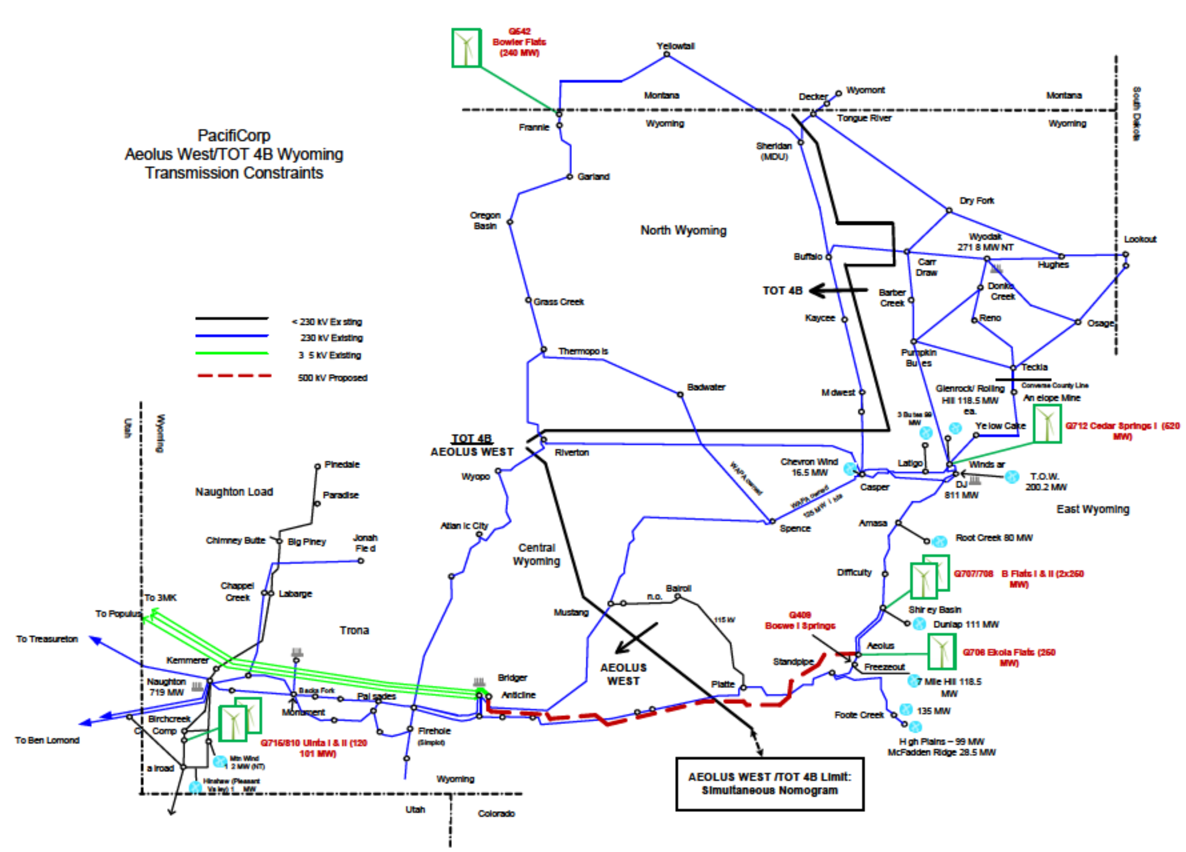
The 2021-22HW base case was modified to reflect the most recent Foote Creek, High Plains, Top of the World and Three Buttes wind generation modeling as per the recent MOD-032 data submitted by each generator owner (GO). Transmission line impedances between Dave Johnston and Standpipe were verified and updated and the transmission line ratings in the 2021-22 heavy winter case were modified to summer ratings, which represent the most conservative thermal limitations. The Platte – Standpipe 230 kV dynamic line rating of 608/666/680 MVA was assumed during the analysis.

The generation resources listed in Table 4 were added to the base case and the existing repowered wind farm generator models and collector system data were updated. The Aeolus West path was stressed by maximizing the output on all of the existing and new wind generation facilities. Output for the repowered wind generation facilities was limited to the existing LGI agreement generation capacity levels. The additional generation in southeast Wyoming was displaced with Jim Bridger, central and southern Utah generation. The Jim Bridger generation output was maintained such that Jim Bridger West path flows were maintained near 2400 MW.

As per the available data obtained for the various wind generation facilities at the time of this study analysis, the base cases were reviewed and adjusted to ensure voltages in the collector system of wind generation facilities were below 1.05 p.u. and that there was no reactive power

GSU loop flow conditions for wind generation facilities that have multiple main generator step-up GSU transformers.

Figure 2
Existing/Proposed Wyoming Generation Resources, and Transmission Constraints



This process involved tuning transformer and generator parameters such that generators were producing appropriate reactive power output. Additionally, within the 230 kV transmission system it was verified that the shunt reactive devices were accurately represented, voltage profiles were normal, reactive power flows were within normal operating ranges and transmission system voltage was maintained to match acceptable PacifiCorp Transmission Voltage Schedules.

4 Path Studies

4.1 Aeolus West vs. TOT 4B

Based on the assumptions outlined above, the study demonstrated that the Aeolus West maximum transfer capability limit is 1829 MW, while meeting all NERC and WECC performance criteria. While this transfer level is 869 MW above the present TOT 4A (960

MW[13]) path limit for similar conditions, east to west transfers have effectively increased by 951 MW due to shifting the Platte area load (82 MW) east of the Aeolus West cut plane. The Aeolus West path was stressed by using 3351 MW of total generation resources, which includes thermal (Dave Johnston, 717 MW - net), existing wind (1124 MW), and new wind (1510 MW) resources. The 240 MW of new wind resource in Big Horn Basin was varied with Wyodak generation as necessary. It was assumed that only the thermal generation at Dave Johnston and Wyodak generating plants in eastern Wyoming would be adjusted to maintain transfers on the Aeolus West and the TOT 4B transmission paths.

Table 5: Aeolus West and TOT 4B Corner Point Cases (See Figure 3)

Case	Aeolus West (MW)	TOT 4B (MW)	Limiting Element	Outage
1	1829	100	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS
2	1803	300	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS
3	1777	500	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS
4	1763	607	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS
			Dave Johnston South Tap – Refinery Tap – Casper 115 kV line	Casper 230 kV CB 1H4001 failure causing Casper – Dave Johnston 230 kV and Casper 230/115 kV transformer outage or Casper – Dave Johnston 230 kV line outage
5	1628	699	Platte- Latham 230 kV line	Anticline – Aeolus 500 kV line outage with RAS

[13] Maximum nomogram point with normal open point at Platte utilizing the dynamic line rating on Platte – Standpipe 230 kV line.

Case	Aeolus West (MW)	TOT 4B (MW)	Limiting Element	Outage
			Dave Johnston South Tap – Refinery Tap – Casper 115 kV line	Casper 230 kV CB 1H4001 failure causing Casper – Dave Johnston 230 kV and Casper 230/115 kV transformer outage or Casper – Dave Johnston 230 kV line outage
6	1125	880	Yellowtail – Sheridan 230 kV line	N-0

See Appendix B for power flow plots.

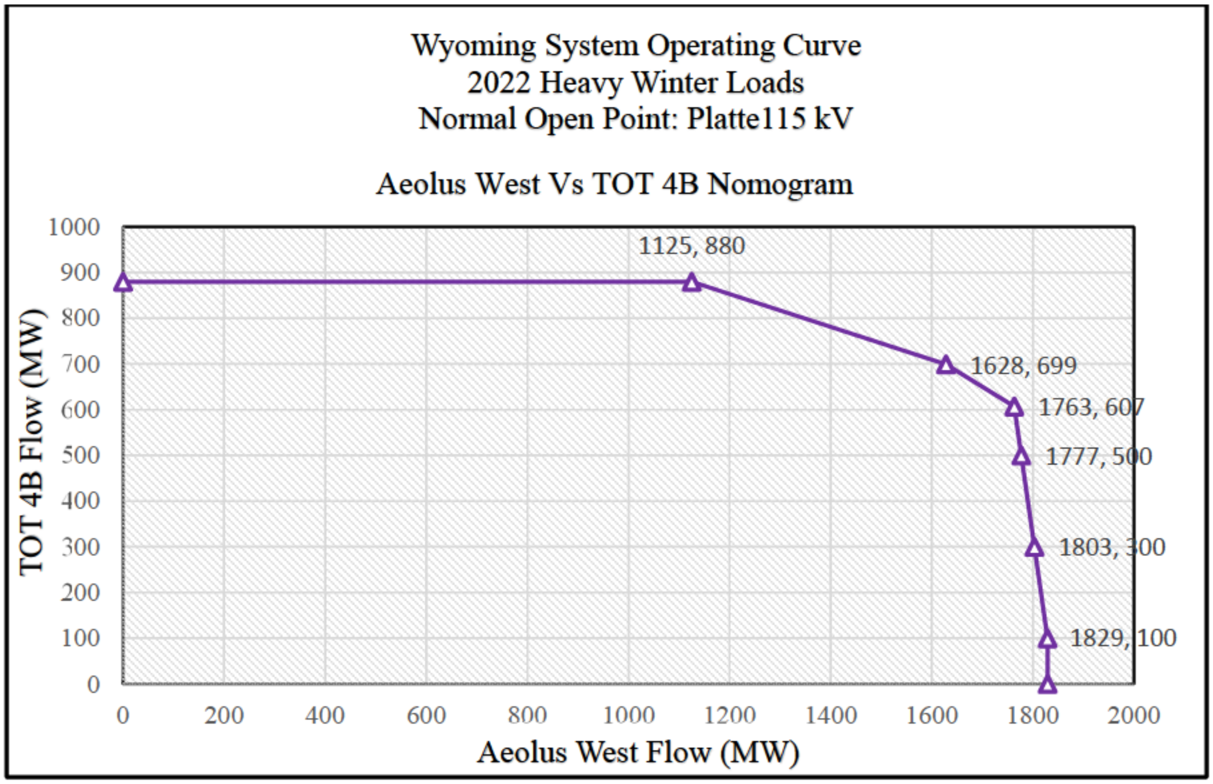
The low voltage issue in the Big Horn Wyoming area is an existing issue for the Yellowtail – Frannie 230 kV line outage or future Q0542 POI – Frannie 230 kV outage. This issue is resolved by adding capacitor banks at various locations in north Wyoming. A project to install a new 30 MVAr shunt capacitor bank at Grass Creek 230 kV, two new 20 MVAr shunt capacitor banks at Frannie and a new 7.5 MVAr capacitor bank at Hilltop 115 kV are proposed.

In the study, one RAS scheme was identified for N-1 outages:

i. Aeolus RAS to trip approximately 630 MW of wind generation depending on pre-outage flow conditions for any of the new transmission element outages between Aeolus – Jim Bridger.

Study results are summarized in Table 5 and illustrated in Figure 3. In reviewing Figure 3, it is evident that the Aeolus West and TOT 4B path interaction are minimized with the addition of the D.2 Project, as indicated by the straight horizontal line (implying no path interaction) when Aeolus West flows are below 1125 MW. The Aeolus West vs TOT 4B nomogram “knee point” is at Aeolus West flows of 1763 MW (TOT 4B, 607 MW). As TOT 4B flows increase from that point, Aeolus West flows reduce; likewise, from the knee point as TOT 4B flows decrease, Aeolus West flows increase.

Figure 3: Aeolus West Vs TOT 4B Nomogram



4.2 Base Case Development

The 2021-22 HW WECC case was modified to simultaneously stress the Aeolus West and the TOT 4B path flows. The Aeolus West path was stressed using all of eastern and north Wyoming resources fora total of 3619 MW (existing and future) wind and net coal resources. These resources were displaced with Jim Bridger and resources in central and southern Utah such that the Jim Bridger West flows were maintained near 2400 MW.

The TOT 4B path flows were adjusted between a minimum of 100 MW and a maximum of 880 MW. Additional resources were exported from PACE to Montana and WAPA to Montana to adjust flows across the TOT 4B path between 300 MW and 880 MW using Crossover, Rimrock and Steam Plant phase shifting transformers in Montana.

The Shiprock, San Juan and Gladstone phase shifting transformers were locked to regulate flow across the TOT 3 path between Colorado and Wyoming.

4.3 Dynamic Stability Analysis

The dynamic stability analysis was performed using PSS/E models provided by both General Electric (GE) and Vestas's for the repowered and new wind generation. The generic model for the Root Creek wind model was updated to the GE0501 model (GE 1.85 units). Top of the World and Three Buttes wind farms in eastern Wyoming were updated to the GE 1.5 wind turbine model provided by GE for PTI V33. A generic WECC model was used for the Latham dynamic reactive device.

The stability study was focused in the eastern Wyoming region to demonstrate the acceptable performance from various new wind farms in the region. The real power, reactive power and voltage output from the new and the existing wind farm generators were reviewed to evaluate their ability to support the transmission grid voltage and system stability during various outage scenarios. Due to the combination of different wind turbine models, dynamic analysis also ensured that no interaction issues were being observed.

The dynamic stability study was performed for one (worst case) nomogram point on the Aeolus West vs. the TOT 4B nomogram curve, which reflected the heaviest Aeolus West flow conditions.

Dynamic stability analysis was performed on selective critical outages based on anticipated post fault impacts on the wind generation performance, especially for the portion of the system with a calculated short circuit ratio of approximately 2.3. See Appendix C for the dynamic stability analysis summary and dynamic plots.

5 Sensitivity Analysis

The sensitivity analysis focused on the evaluation of two different RAS generation tripping scenarios to ascertain which scheme would be the most effective at tripping generation following outage of the D.2 Project facilities between Bridger and Aeolus.

A dynamic stability sensitivity analysis was performed to evaluate the system impact and generator performance for a single element outage on the D.2 segment between Aeolus 230 kV and Bridger 345 kV buses which requires a RAS for generator tripping. Two different sets of generator tripping locations and tripping levels (approximately 630 MW) were selected. The generation tripping of 607 MW, which includes High Plains, Seven Mile Hill, Q706 and Dunlap wind generation was compared with generation tripping of 628 MW, which includes High Plains, Q0706 and Q0707 wind generation. For summary results and plots, please see dynamic simulation cases 1a – 1f2 in Appendix C.

6 Study Conclusions

Technical studies demonstrated that with the addition of the planned D.2 Project facilities to the Wyoming transmission system, system performance will meet all NERC and WECC performance criteria.

Updated power flow studies demonstrate that by utilizing existing and planned southeast Wyoming resources[5], the Aeolus West transmission path can transfer up to 1829 MW under simultaneous transfer conditions with the TOT 4B transmission path, effectively[6] increasing the east to west transfer levels across Wyoming by 951 MW. Power flow findings also indicated:

- Dynamic voltage control is necessary at the Latham 230 kV substation to mitigate low voltage conditions resulting from loss of Bridger/Anticline – Aeolus transmission facilities.
- Under certain operating conditions, one RAS scheme will need to be implemented to trip generation following the outage of specific transmission facilities.
- The location (and output level) of new and repowered wind resources can influence the transfer capability level across the Aeolus West transmission path, the Aeolus West and TOT 4B nomogram curve and the area under the nomogram curve.

Dynamic stability studies evaluated a wide range of critical system disturbances in eastern Wyoming. The analyses identified two outages with poor voltage performance, and another outage identified a wind turbine modeling problem. These issues are all attributed to the wind turbine models at the Q0706, Q0707 and Q0708 projects. PacifiCorp is working with the wind turbine manufacture to resolve these issues. Aside from these issues, the studied outages evaluated meet the dynamic performance criteria with the system being stable and damped.

Report Appendices

Appendix A – Path Definitions

Appendix B – Power Flow Plots

Appendix C – Dynamic Stability Results (Case C7)





2013

Integrated Resource Plan

Volume I

Let's turn the answers on.

April 30, 2013

PACIFICORP
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

This 2013 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

For more information, contact:
PacifiCorp
IRP Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
irp@pacificorp.com
http://www.pacificorp.com

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Cover Photos (Top to Bottom):
Transmission: *Sigurd to Red Butte Transmission Segment G*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Wind Turbine: *Leaning Juniper I Wind Project*
Thermal-Gas: *Chehalis Power Plant*
Solar: *Black Cap Photovoltaic Solar Project*

CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2013 Integrated Resource Plan (2013 IRP), representing the 12th plan submitted to state regulatory commissions, presents a framework for future actions that PacifiCorp will take to provide reliable, reasonable-cost service with manageable risks to its customers. It was developed with participation from numerous public stakeholders, including regulatory staff, advocacy groups, and other interested parties.

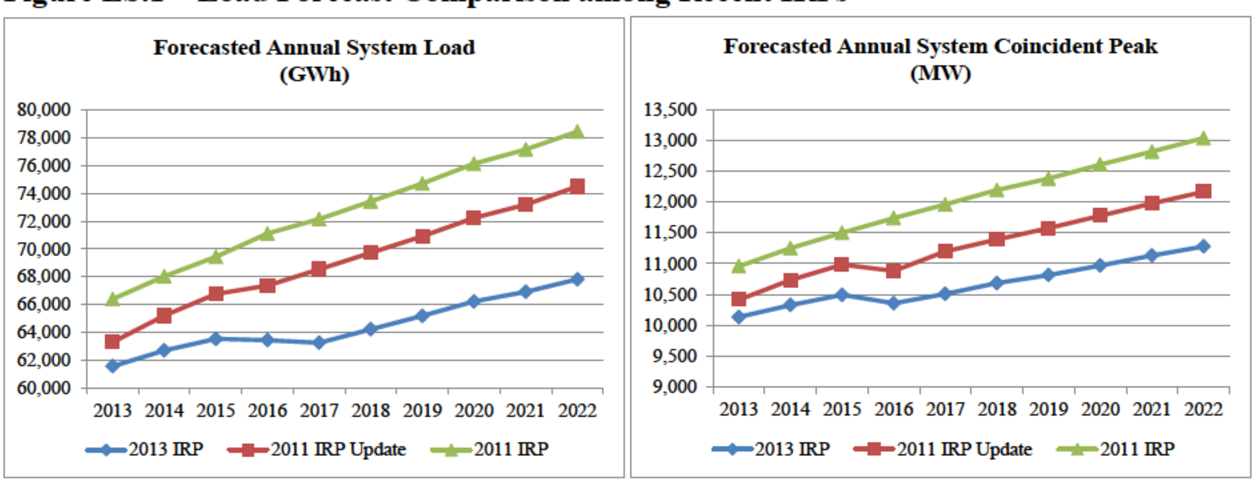
The key elements of the 2013 IRP include (1) a finding of resource need, focusing on the 10-year period 2013-2022, (2) the preferred portfolio of incremental supply-side and demand-side resources to meet this need, and (3) an action plan that identifies the steps the Company will take during the next two to four years to implement the plan. The process and outcome of the IRP—the preferred portfolio and action plans—meet applicable state IRP standards and guidelines. PacifiCorp continues to plan on a system-wide basis while accommodating state resource acquisition mandates and policies.

2013 IRP Highlights

Development of the 2013 IRP involved balanced consideration of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. Key drivers to the 2013 IRP preferred portfolio and associated action plan include the following:

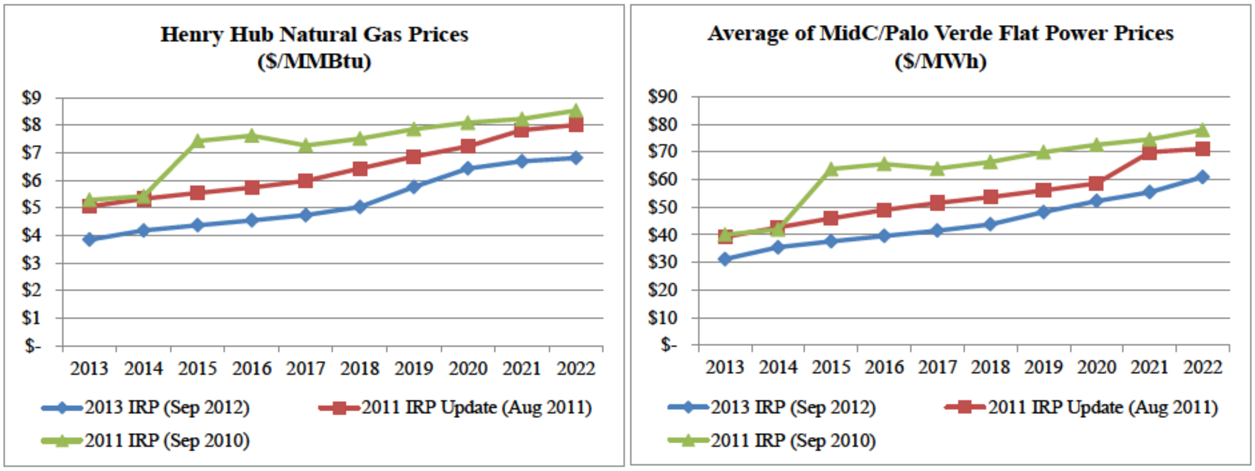
- As shown in Figure ES.1, the Company's load forecast in the 2013 IRP is down in relation to projected loads used in the 2011 IRP and 2011 IRP Update. The lower load forecast is driven significantly by industrial self generation taking advantage of low natural gas prices, as well as by load request cancellations in Utah and Wyoming and postponements prompted by prolonged recessionary impacts and permitting issues. The reduced load forecast has greatly mitigated, but not eliminated the need for resources in the front ten years of the planning horizon, and is a significant driver in resource portfolio modeling performed for the 2013 IRP.

Figure ES.1 – Load Forecast Comparison among Recent IRPs



- Figure ES.2 shows that base case wholesale power prices and natural gas prices used in the 2013 IRP are significantly lower than the base case market prices used in the 2011 IRP and 2011 IRP Update. The decline in forward natural gas prices has largely been influenced by continued growth in prolific shale gas plays in North America. With continued declines in natural gas prices and reduced regional loads, forward power prices have also declined significantly over the past two years. Given these favorable market conditions, front office transactions play a critical role in meeting coincident peak loads throughout the front ten years of the planning horizon.

Figure ES.2 – Power and Natural Gas Price Comparison among Recent IRPs



- In all portfolios evaluated in the 2013 IRP, energy efficiency resources play an important role in meeting load growth throughout the front ten years of the planning horizon. In the 2013 IRP preferred portfolio, the accumulated acquisition of incremental energy efficiency resources meets 67 percent of currently forecasted load growth from 2013 levels by 2022, and the 2013 IRP action plan identifies steps the Company will take in the next two to four years to accelerate acquisition of cost-effective energy efficiency resources.

- Policy and market developments have contributed to higher renewable resource costs and reduced benefits. On the policy front, policy makers continue to debate Federal budget deficits, and deep philosophical differences have thus far proven to be a barrier to budgetary compromise, making the long-term outlook for federal tax incentives that have traditionally benefited new renewable resources highly uncertain. Policy makers have also not succeeded in passing federal greenhouse gas legislation for consideration by the President. While the U.S. Environmental Protection Agency (EPA) has proposed new source performance standards to regulate greenhouse gas emissions from new sources, it has not finalized those standards, nor has it established a schedule to promulgate rules applicable to existing sources. With higher after-tax costs, lower power prices, and continued greenhouse gas regulation uncertainty, the need for new renewable resources will be driven by state-specific renewable portfolio standard (RPS) regulations. To mitigate the cost of RPS compliance, analyses in the 2013 IRP supports the use of unbundled renewable energy credits (RECs) to meet state RPS obligations through the first ten years of the planning period.

- On March 15, 2013, the Utah Public Service Commission approved the Company's application for a Certificate of Public Convenience and Necessity (CPCN) for the Sigurd to Red Butte transmission project. The Company began construction of the Sigurd to Red Butte transmission project in April, 2013 with a scheduled in-service date of June, 2015. For the 2013 IRP, the Company has completed preliminary analysis of the Windstar to Populus transmission project (Energy Gateway Segment D) that supports on-going permitting activities. Permitting activities for other Energy Gateway transmission segments will continue in parallel with the on-going development of analytical tools that can be used to evaluate transmission benefits that are not traditionally captured in the resource portfolio modeling process used in the IRP.

- The Company has analyzed in the 2013 IRP environmental investments required to meet known and prospective compliance obligations across PacifiCorp's existing coal fleet. Supported by analyses performed as part of the 2013 IRP and analyses performed in recent regulatory filings, the Company plans to convert Naughton Unit 3 to a natural gas-fired facility and to install environmental investments required to meet near term compliance obligations at the Hunter Unit 1, Jim Bridger Unit 3, and Jim Bridger Unit 4 generating units. Installation of emission control equipment at these facilities will reduce emissions of nitrous oxides (NO_X) and sulfur dioxide (SO_2) and contribute to improved visibility in the region. The Company plans to continue to evaluate environmental investments required to meet known and prospective environmental compliance obligations at existing coal units in future IRPs and future IRP Updates.

Modeling and Process Improvements

In developing the 2013 IRP, the Company has significantly advanced its analytical methods and portfolio development approach. The notable improvements that are summarized below have very much influenced the 2013 IRP and establish a sound foundation for analysis in future IRPs.

- <u>Energy Gateway Transmission</u>

  In contrast to the 2011 IRP, where analysis of Energy Gateway transmission investments preceded resource portfolio modeling, Energy Gateway transmission investments have been integrated into the portfolio modeling process for the 2013 IRP. This was achieved by replicating the development of resource portfolios among five different Energy Gateway transmission scenarios. Consequently, 94 unique core case resource portfolios were produced in the 2013 IRP, nearly five times the number of core case portfolios developed for the 2011 IRP.

  In addition to incorporating Energy Gateway transmission investments into the resource portfolio modeling process, the 2013 IRP introduces the System Operational and Reliability Benefits Tool (SBT), which identifies and quantifies transmission benefits that are not captured using production cost dispatch models traditionally used for IRP analyses. In this way, the SBT identifies, measures, and monetizes benefits that are incremental to those identified in the resource portfolio modeling process. Analysis using the SBT supports investment in the Sigurd to Red Butte transmission project and preliminary application of the SBT to the Windstar to Populus transmission project supports continued permitting of Energy Gateway Segment D. The SBT will continue to be developed and will be applied to additional Energy Gateway transmission projects for analysis in future IRPs.

- Existing Coal Resources

  Building upon modeling techniques developed in the 2011 IRP and 2011 IRP Update, environmental investments required to achieve compliance with known and prospective regulations at existing coal resources have been integrated into the portfolio modeling process in the 2013 IRP. Potential alternatives to environmental investments associated with known and prospective compliance obligations tied to Regional Haze rules, Mercury and Air Toxics Standards (MATS), regulation of coal combustion residuals (CCR), and regulation of cooling water intakes are considered in the development of *all* resource portfolios developed for the 2013 IRP. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. In addition to integrating coal unit environmental investment decisions into the portfolio development process, the Company has completed detailed financial analysis of near-term investment decisions in Confidential Volume III of the 2013 IRP.

- Energy Efficiency

  PacifiCorp continues to evaluate energy efficiency as a resource that competes with traditional supply-side resource alternatives when developing resource portfolios that are compared under a range of cost and risk metrics. The 2013 IRP includes for the first time core case resource portfolios developed assuming accelerated acquisition of energy efficiency resources. While the assumptions developed for these cases require further validation and review, cost and risk analysis of these portfolios have led to action items in the 2013 IRP action plan to accelerate acquisition of cost-effective energy efficiency resources.

  In addition to evaluating acceleration of energy efficiency resources in the 2013 IRP, the Company greatly expanded its representation of energy efficiency resource attributes that influence selection in any given portfolio. Energy efficiency resources were modeled with additional cost granularity by increasing the number of cost steps that delineate groupings of different energy efficiency measures. In the 2011 IRP, energy efficiency resources for a given state were grouped into nine different cost levels, whereas the 2013 IRP modeling was performed using 27 different cost levels to represent energy efficiency resource opportunities in each state. Implementation of this modeling refinement deteriorated model performance, and the Company has developed an action item to study trade-offs between resource selections and model run-times at different levels of granularity.

- Renewable Portfolio Standards

  The 2013 IRP includes portfolios with and without renewable portfolio standard (RPS) requirements to isolate how system costs and portfolio risks are affected when new renewable resources are added to a portfolio for the sole purpose of meeting state-specific RPS compliance targets. In those cases where RPS compliance targets are assumed and incremental renewable resources are needed for the sole purpose of achieving RPS targets, the RPS Scenario Maker model was introduced into the 2013 IRP. The RPS Scenario Maker model was used to establish a minimum level of new renewable resources needed to meet RPS compliance targets while considering compliance flexibility mechanisms such as "banking" unique to each state RPS program.

- Public Process

The involvement of stakeholders is a critical element of the IRP process. Over the course of developing the 2013 IRP, the Company expanded its open and collaborative approach to resource planning by increasing opportunities for stakeholder participation. The Company hosted 15 public input meetings, more than twice the number of public input meetings held for the 2011 IRP, supplemented communications with stakeholder conference calls, and held five state meetings. In addition, the Company made available to stakeholders a website used to provide data and to communicate Company responses to stakeholder questions received throughout the public process.

Resource Need

PacifiCorp's need for new resources is determined by developing a capacity load and resource balance that considers the coincident system peak load hour capacity contribution of existing resources, forecasted loads and sales, and reserve requirements. For capacity expansion planning, the Company uses a 13 percent planning reserve margin, which is applied to PacifiCorp's obligation net of offsetting "load resources" such as dispatchable load control capacity.[1]

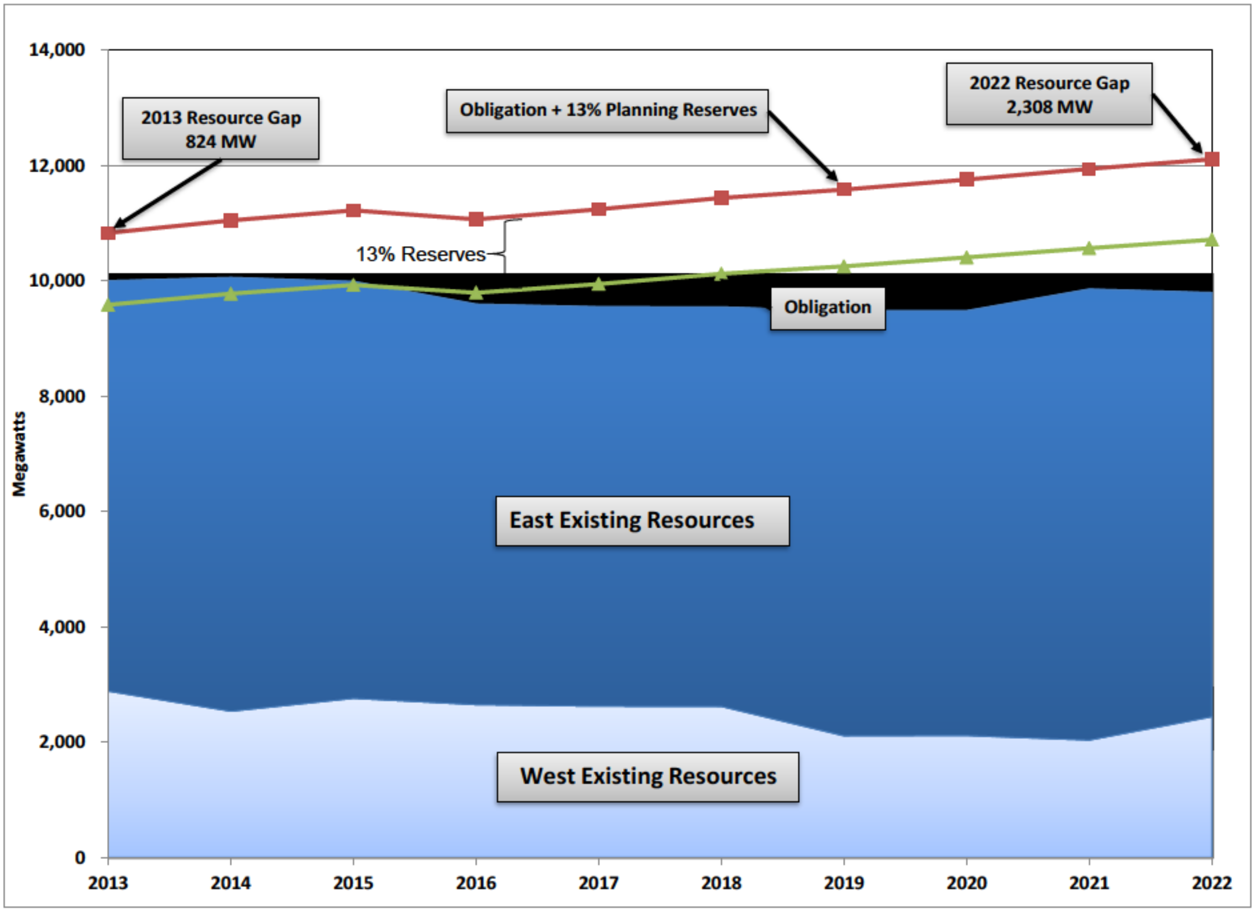
Table ES.1 shows the Company's annual capacity position for 2013 through 2022, and Figure ES.3 graphically highlights the capacity resource gap in relation to currently owned and contracted east and west-side resources. Without new resources, the system experiences a capacity deficit of 824 megawatts in 2013, down by 57 percent as compared to the 2011 IRP and down by 39 percent as compared to the 2011 IRP Update. By 2022, the system capacity deficit reaches 2,308 megawatts. Over the 2013 to 2022 timeframe, the system peak load is forecasted to grow at a compounded annual rate of 1.2 percent (prior to forecasted load reductions from energy efficiency). On an energy basis, PacifiCorp expects system-wide average load growth of 1.1 percent per year.

Table ES.1 – PacifiCorp 10-year Capacity Position Forecast (Megawatts)

System	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Resources	10,010	10,065	9,996	9,602	9,556	9,553	9,487	9,488	9,864	9,803
Obligation	9,588	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718
Reserves (Based on 13% Target)	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Obligation + 13% Planning Reserves	10,834	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)
Reserve Margin	4.4%	2.9%	0.6%	(2.0%)	(4.0%)	(5.6%)	(7.5%)	(8.8%)	(6.7%)	(8.5%)

[1]The 13 percent planning reserve margin is supported by a stochastic loss of load probability study that is summarized in Volume II, Appendix I of the 2013 IRP.

Figure ES.3 – PacifiCorp Capacity Resource Gap



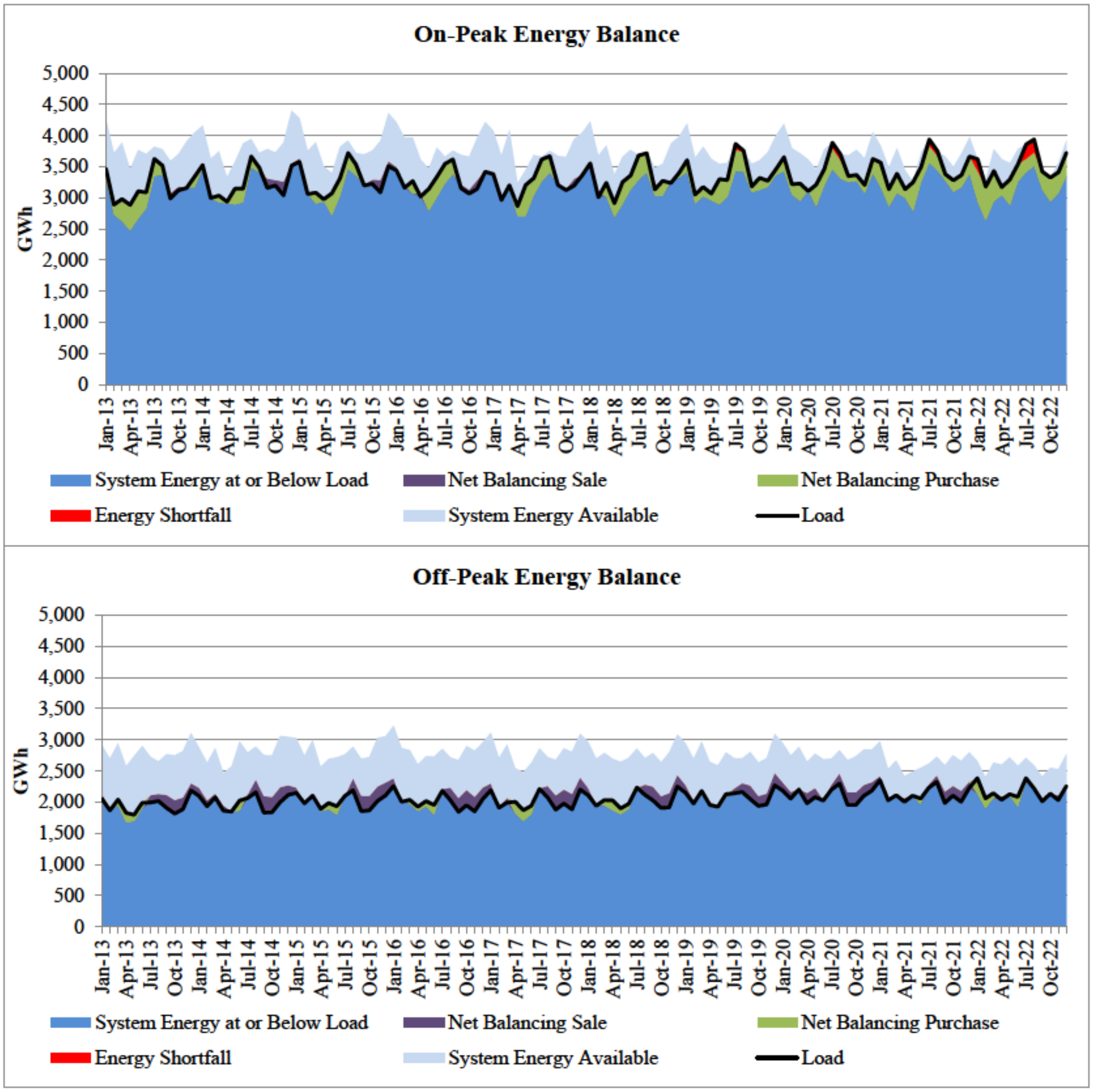
The capacity position shows how existing resources and loads balance during the coincident peak load hour of the year inclusive of a planning reserve margin. Outside of the peak hour, the Company economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, the Company can dispatch resources that in aggregate exceed then-current load obligations, facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs fall below prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how the Company manages net power costs.

Figure ES.4 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and current wholesale power and natural gas prices.[2] The figure shows expected monthly energy production from system resources during on-peak and off-peak periods in relation to load assuming no additional resources are added to PacifiCorp's system. At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak

[2] On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday, excluding NERC-observed holidays. All other hours define off-peak periods.

periods. Figure ES.4 also shows how much system energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and are indicative of short energy positions absent the addition of incremental resources to the portfolio. During on-peak periods, the first energy shortfall appears in July 2018, and by 2022 available system energy falls short of monthly loads in January, July, August, and October. During off-peak periods, there are no energy shortfalls through the 2022 timeframe.

Figure ES.4 – Economic System Dispatch of Existing Resources in Relation to Monthly Load



Future Resource Options and Portfolio Modeling

In line with state IRP standards and guidelines, PacifiCorp included a wide variety of resource options in portfolio modeling covering generation, demand-side management and transmission. Cost and performance assumptions for resource alternatives were developed using multiple sources, including: third party estimates, data from actual and projected PacifiCorp or utility industry installations, and data from recent request for proposals and requests for information. Table ES.2 summarizes the wide range of resource alternatives evaluated in the 2013 IRP.

Table ES.2 – 2013 IRP Resource Options*

Natural Gas	Other Thermal	Renewable	Energy Storage	Distributed Generation	Class 1 DSM (Direct Load Control)	Class 2 DSM (Energy Efficiency)	Class 3 DSM (Demand Response)
▪ SCCT Aero ▪ Intercooled SCCT Aero ▪ SCCT Frame ▪ IC Recip. Engine ▪ CCCT (2x1) F-class ▪ CCCT (2x1) G/H-class ▪ CCCT (1x1) G/H-class ▪ CCCT (1x1) J-class ▪ CCCTs with and without duct firing	▪ IGCC with carbon capture and sequestration ▪ Nuclear fission	▪ Geothermal (PPAs) ▪ Wind ▪ Solar PV (fixed tilt & tracking) ▪ Biomass	▪ Pumped Storage ▪ Sodium-Sulfur Battery ▪ Advanced Fly Wheel ▪ Compressed Air Energy Storage	▪ Reciprocating Engines ▪ Gas Turbine ▪ Microturbine ▪ Fuel Cell ▪ Commercial Biomass, Anaerobic Digester ▪ Industrial Biomass, Waste ▪ Rooftop Solar PV ▪ Solar Water Heaters	▪ Residential Central Air & Water Heating ▪ Small Commercial Central Air & Water Heating ▪ Irrigation Load Curtailment ▪ Commercial Curtailment ▪ Industrial Curtailment	▪ Residential, Commercial, Industrial, Irrigation, and Street Lighting Measures ▪ 27 measure bundles grouped by cost among five states ▪ Energy Trust of Oregon Energy Efficiency Measures as Applicable for Oregon	▪ Residential time-of-use rates ▪ Commercial Critical Peak Pricing ▪ Commercial and Industrial Demand Buyback ▪ Voluntary Irrigation Time-of-Use

*SCCT = simple cycle combustion turbine; CCCT = combined cycle combustion turbine; IGCC = integrated gasification combined cycle, PPA = power purchase agreement; PV = photo voltaic, DSM = demand side management

PacifiCorp's IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios, and consists of eight phases:

- Define input scenarios for portfolio development
- Price forecast development (natural gas and wholesale electricity by market hub)
- Optimize portfolio development using PacifiCorp's *System Optimizer* capacity expansion model for cases without RPS requirements
- Develop a renewable resource floor, reflecting renewable resource additions chosen in optimized portfolios from cases that exclude RPS requirements needed to achieve compliance for cases that do include RPS assumptions
- Optimize portfolio development using PacifiCorp's *System Optimizer* capacity expansion model for cases with RPS requirements
- Stochastic Monte Carlo production cost simulation of optimized portfolios
- Selection of top-performing portfolios using a three-phase screening process that incorporates stochastic portfolio cost and risk assessment measures
- Preliminary preferred portfolio selection, followed by additional analysis and determination of the final preferred portfolio

PacifiCorp worked with stakeholders to define 19 input scenarios, or "core cases", which were applied across five different Energy Gateway transmission scenarios totaling 94 different variations of resource portfolios.[3] The 19 different core cases were categorized into four different themes:

(1) Reference: There are three different core cases developed for the Reference Theme. Each case relied upon base case assumptions for market prices, environmental policy inputs, energy efficiency assumptions, and load projections. RPS assumptions differentiate the three cases in the Reference Theme, with one case assuming no state or federal RPS requirements, one case assuming only state RPS requirements, and one case assuming both state and federal RPS requirements must be met.

(2) Environmental Policy: There are 11 different core cases developed for the Environmental Policy Theme. Five of the 11 cases reflect base case assumptions for Regional Haze requirements on existing coal units, and six of the 11 cases assume more stringent Regional Haze requirements. Differentiating the sets of cases with different Regional Haze compliance requirements are varying assumptions for market prices (low, medium, and high), CO_2 prices (zero, medium, and high), RPS requirements (with and without state and federal RPS), and energy efficiency.

(3) Targeted Resources: There are four different core cases developed for the Targeted Resource Theme. Each of the cases is characterized by alternative assumptions for specific resource types to understand how these assumptions influence resource portfolios, costs, and risk. One of the four cases prevents combined cycle resources from being added to the resource portfolio and assumes energy efficiency resources can be acquired at an accelerated rate. The second of the four cases in this theme assumes that geothermal power purchase agreement resources will be used to meet RPS requirements. The third of four cases in this theme assumes a spike in power prices over the period 2017 through 2022 and assumes natural gas prices will rise above base case levels over the entirety of the planning horizon. The fourth case in this theme targets clean energy resources and assumes CO_2 prices rise consistent with a federal hard cap scenario, that natural gas prices rise above those assumed in the base case, that federal tax incentives for renewable resources are extended through 2019, and that energy efficiency resources can be acquired at an accelerated rate.

(4) Transmission: The Transmission Theme included one core case, which assumes that third party transmission can be purchased from a newly built line as an alternative to the Company's Gateway Segment D project. This case was only analyzed in four of the five Energy Gateway scenarios that include the Gateway Segment D project.

PacifiCorp selected top-performing portfolios on the basis of system costs using Monte Carlo simulations of each portfolio over a twenty year planning horizon. The Monte Carlo runs capture stochastic behavior of electricity prices, natural gas prices, loads, thermal unit availability, and hydro availability. The relative average cost among portfolios and the upper tail cost among portfolios are used to evaluate cost and risk metrics among candidate portfolios and are used to identify top performing resource portfolios that inform the Company's selection of the preferred

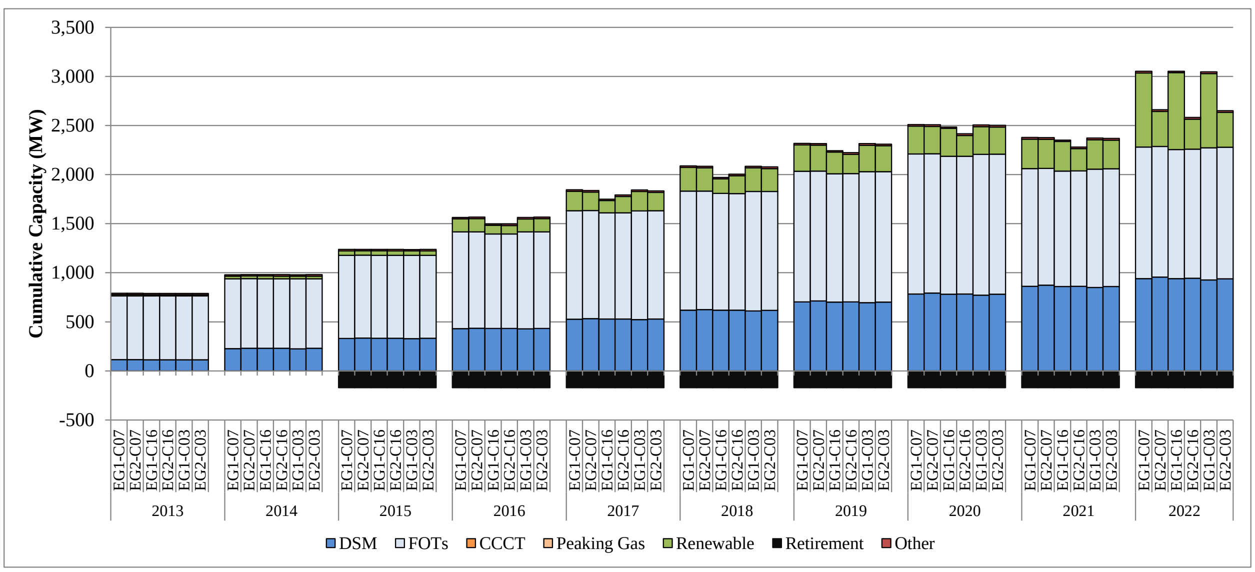
[3] One of the input scenarios is applicable to four out of the five Energy Gateway transmission scenarios.

portfolio. In making its preferred portfolio selection, the Company considers measures of risk-adjusted portfolio costs, customer rate impacts, CO_2 emissions, and supply reliability.

In the 2013 IRP, some portfolios developed under the assumption that acquisition of demand side management (DSM) resources can be accelerated performed well on a risk adjusted cost basis. However, given uncertainties in incentive and administrative costs and delivery risks associated with accelerating acquisition of DSM resources, these portfolios were not selected as the preferred portfolio. Nonetheless, the potential benefits of accelerating acquisition of DSM resources has prompted the Company to develop action items in 2013 IRP Action Plan targeting accelerated acquisition of cost effective DSM resources.

Figure ES.5 summarizes the nameplate capacity of cumulative resource selections through 2022 among top performing portfolios developed under base case DSM acquisition ramp rate assumptions. With reduced load expectations and market prices, resource selections among the top performing portfolios over the first 10 years of the planning horizon are dominated by energy efficiency and front office transaction (FOT) resources, and there are no new CCCT resources required over this timeframe. Among these cases, renewable resources are added in different quantities and at different times for the sole purpose of meeting west side state RPS requirements. The variability in quantity, type, and timing of new renewable resources is dependent on whether the Windstar to Populus transmission project is built.

Figure ES.5 – Comparison of Resource Types in Top Performing Portfolios



In the final screening stage of the 2013 IRP portfolio analysis, the Company evaluated an alternative strategy to meet Washington RPS requirements with unbundled RECs. This analysis shows that a compliance strategy focused on acquiring unbundled RECs is favorable on a cost and risk basis, and supports 2013 IRP action items to issue competitive market solicitations for unbundled REC products over the next two to four years.

The 2013 IRP Preferred Portfolio

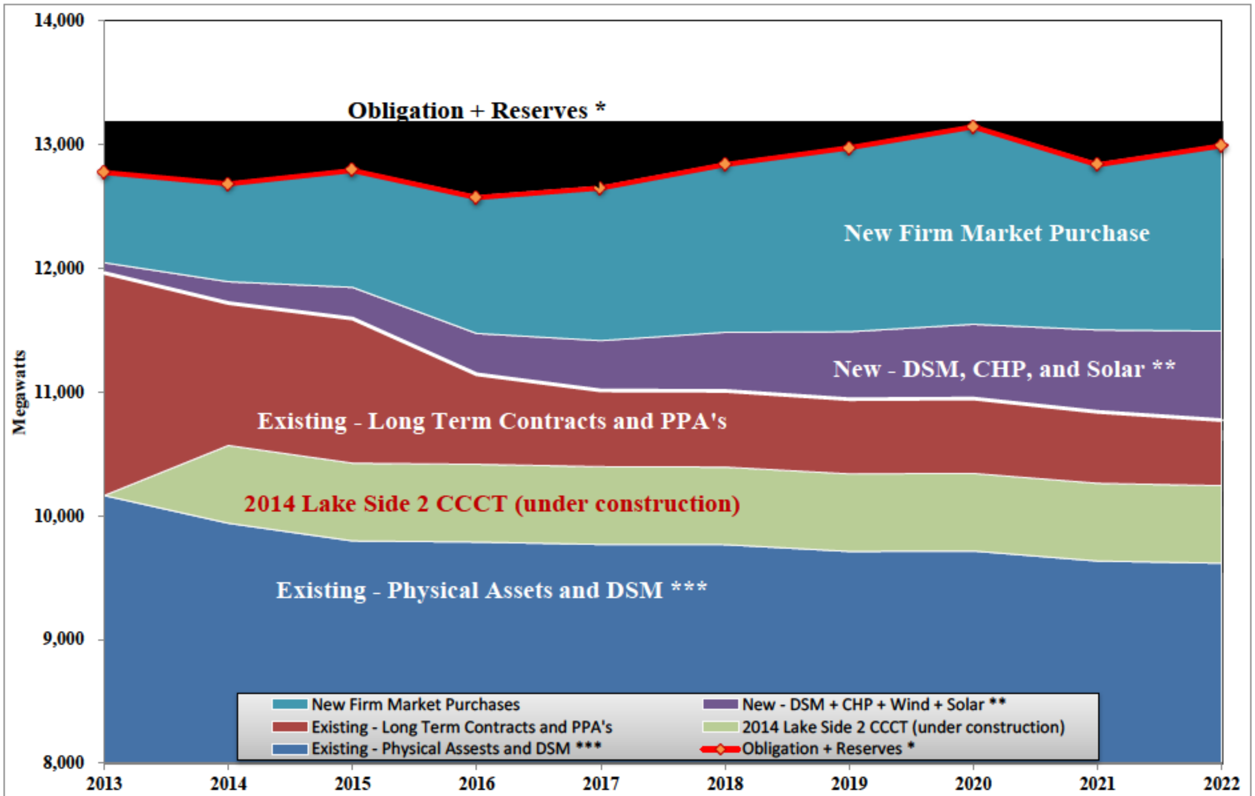
Table ES.3 lists the resource types and annual nameplate megawatt capacity additions over the period 2013 through 2032. Figure ES.4 shows how the preferred portfolio, along with existing resources, meets capacity requirements at the time of system peak through 2022. The drop in obligation and reserves in 2016 and 2021 coincides with termination of two exchange contracts. With reduced loads and favorable market conditions, incremental resource needs in the front 10 years of the planning horizon are met largely with cost-effective energy efficiency acquisitions and firm market purchases.

As informed by portfolio modeling completed for the 2013 IRP, the Company's action plan focuses on accelerating acquisition of cost effective DSM measures, to take advantage of the risk mitigation benefits of DSM resources by reducing the need for new firm market purchases in the near-term. With policy and market drivers contributing to unfavorable economics for new renewable resources, renewable resource additions in the 2013 IRP preferred portfolio reflect a near-term unbundled REC compliance strategy. Near-term renewable resources include small scale utility solar resources needed to meet Oregon requirements and distributed solar resources associated with the Utah Solar Incentive Program. Over the long-term, the 2013 IRP preferred portfolio includes additional wind resources, totaling 650 megawatts in the 2024 to 2025 timeframe, which contribute to meeting long-term state and assumed RPS obligations.

Table ES.3 – 2013 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Expansion Options																					
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	423	-	-	-	661	-	1,084	-	-	2,813
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181	362
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	70	67	67	69	66	63	54	57	56	1,593
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	19	88	-	-	-	193
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	650
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	15	15	15	15	15	15	15	15	15	293
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	21
Front Office Transactions	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246	n/a
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(502)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-	(1,535)
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14
Total	**791**	**1,486**	**802**	**1,102**	**1,218**	**1,315**	**1,427**	**1,515**	**1,287**	**1,431**	**1,511**	**2,054**	**1,606**	**1,509**	**1,640**	**1,648**	**1,639**	**1,685**	**1,281**	**1,500**	

Figure ES.6 – Addressing PacifiCorp's Peak Capacity Deficit, 2013 through 2022

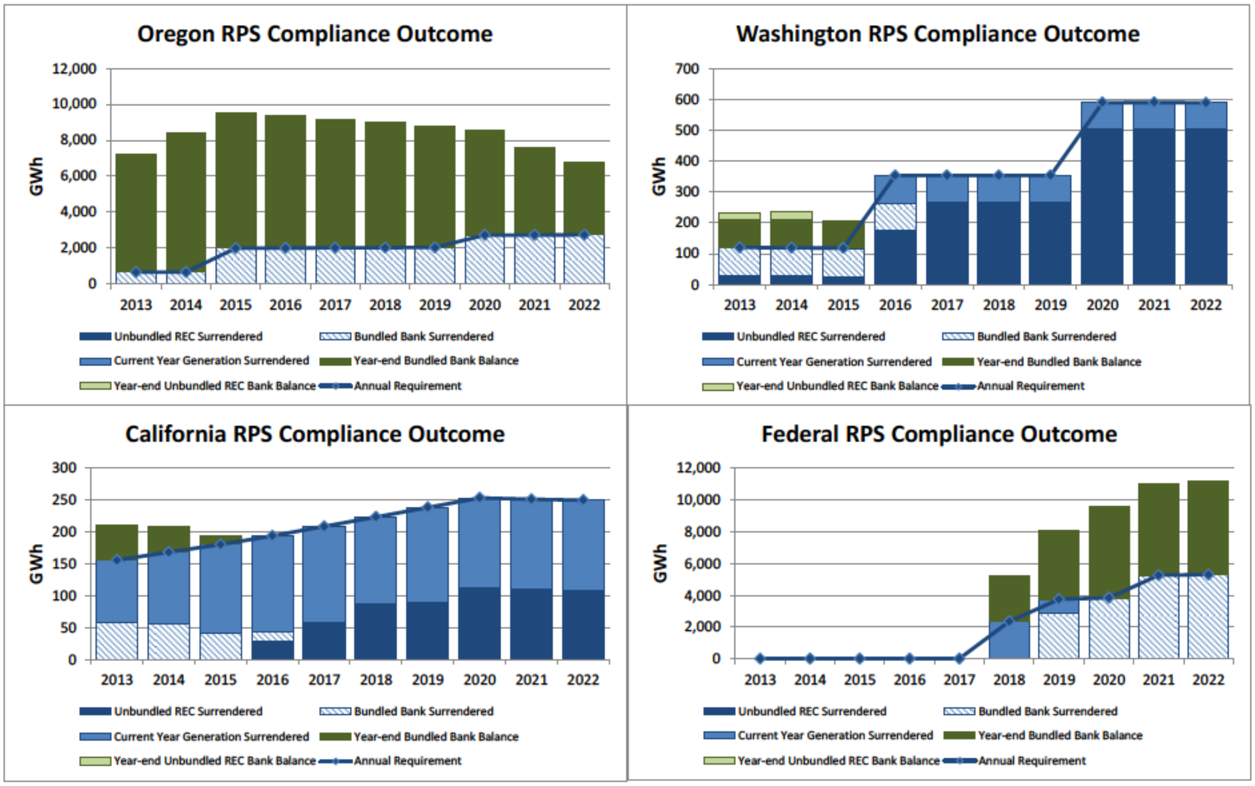


* Includes 13% Planning Reserves, Sales and Non-Owned Reserves
** Solar resources peak contribution is 8 MW by 2022 and Combined Heat and Power (CHP) contributes 12 MW.
*** Includes retirements, turbine upgrades, and gas repower. DSM includes both Class 1 and 2.

Figure ES.7 shows PacifiCorp's forecasted RPS compliance position for the California, Oregon, and Washington[4] programs, along with a federal RPS program scenario[5], covering the period 2013 through 2022 based on the preferred portfolio. Utah's RPS goal is tied to a 2025 compliance date, so the 2013 to 2022 position is not shown below. However, PacifiCorp meets the Utah 2025 state target of 20 percent based on eligible Utah RPS resources, and has significant levels of banked RECs to sustain continued future compliance. PacifiCorp anticipates utilizing flexible compliance mechanisms such as banking and/or tradable RECs where allowed, to meet RPS requirements.

[4] The Washington RPS requirement is tied to January 1st of the compliance year.
[5] The assumed federal RPS requirements are applied to retail sales, with a target of 4.5 percent beginning in 2018, 7.1 percent in 2019-2020, 9.8 percent in 2021-2022, 12.4 percent in 2023-2024, and 20 percent in 2025

Figure ES.7 – Annual State and Federal RPS Position Forecasts



The 2013 IRP Action Plan

The 2013 IRP Action Plan identifies specific actions the Company will take over the next two to four years. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2013 IRP process. Table ES.4 details specific 2013 IRP action items by category.

Table ES.4 – 2013 IRP Action Plan

Action Item	1. Renewable Resource Actions
1a.	**<u>Wind Integration</u>** • Update the wind integration study for the 2015 IRP. The updated wind integration study will consider the implications of an energy imbalance market along with comments and feedback from the technical review committee and IRP stakeholders provided during the 2012 Wind Integration Study.
1b.	**<u>Renewable Portfolio Standard Compliance</u>** • With renewable portfolio standard (RPS) compliance achieved with unbundled renewable energy credit (REC) purchases, the preferred portfolio does not include incremental renewable resources prior to 2024. Given that the REC market lacks liquidity and depth beyond one year forward, the Company will pursue unbundled REC requests for proposal (RFP) to meet its state RPS compliance requirements. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard obligations. – Issue at least annually, RFPs seeking historical, then current-year, or forward-year vintage unbundled RECs that will qualify for Oregon renewable portfolio standard obligations. As part of the solicitation and bid evaluation process, evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify for California renewable portfolio standard obligations.
1c.	**<u>Renewable Energy Credit Optimization</u>** • On a quarterly basis, issue reverse RFPs to sell RECs not required to meet state RPS compliance obligations.

1d.	**<u>Solar</u>** • Issue an RFP in the second quarter of 2013 soliciting Oregon solar photovoltaic resources to meet the Oregon small solar compliance obligation (Oregon House Bill 3039). Coordinate the selection process with the Energy Trust of Oregon to seek 2014 project funding. Complete evaluation of proposals and select potential winning bids in the fourth quarter of 2013. • Issue a request for information 180 days after filing the 2013 IRP to solicit updated market information on utility scale solar costs and capacity factors.
1e.	**<u>Capacity Contribution</u>** • Track and report the statistics used to calculate capacity contribution from wind resources and available solar information as a means of testing the validity of the peak load carrying capability (PLCC) method.
Action Item	**2. Distributed Generation Actions**
2a.	**<u>Distributed Solar</u>** • Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity. Beginning in June 2014, as stipulated in the Order in Docket No. 11-035-104, the Company will file an Annual Report with program results, system costs, and production data. These reports will also provide an opportunity to evaluate and improve the program as the Company will use this opportunity to recommend changes. Interested parties will have an opportunity to comment on the report and any associated recommendations.
2b.	**<u>Combined Heat & Power (CHP)</u>** • Pursue opportunities for acquiring CHP resources, primarily through the Public Utilities Regulatory Policies Act PURPA Qualifying Facility contracting process. For the 2013 IRP Update, complete a market analysis of CHP opportunities that will: (1) assess the existing, proposed, and potential generation sites on PacifiCorp's system; (2) assess availability of fuel based on market information; (3) review renewable resource site information (i.e. permits, water availability, and incentives) using available public information; and (4) analyze indicative project economics based on avoided cost pricing to assist in ranking probability of development.
Action Item	**3. Firm Market Purchase Actions**
3a.	**<u>Front Office Transactions</u>** • Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017. – Resources will be procured through multiple means, such as periodic market RFPs that seek resources less than five years in term, and bilateral negotiations.

Action Item	
	– Include in the 2013 IRP Update a summary of the progress the Company has made to acquire front office transactions over the 2014 to 2017 forward period.
Action Item	**4. Flexible Resource Actions**
4a.	**<u>Energy Imbalance Market (EIM)</u>** • Continue to pursue the EIM activities with the California Independent System Operator and the Northwest Power Pool to further optimize existing resources resulting in reduced costs for customers.
Action Item	**5. Hedging Actions**
5a.	**<u>Natural Gas Request for Proposal</u>** • Convene a workshop for stakeholders by October 2013 to discuss potential changes to the Company's process in evaluating bids for future natural gas RFPs, if any, to secure additional long-term natural gas hedging products.
Action Item	**6. Plant Efficiency Improvement Actions**
6a.	**<u>Plant Efficiency Improvements</u>** • Production efficiency studies have been conducted to satisfy requirements of the Washington I-937 Production Efficiency Measure that have identified categories of cost effective production efficiency opportunity. – By the end of the first quarter of 2014, complete an assessment of the plant efficiency opportunities identified in the Washington I-937 studies that might be applicable to other wholly owned generation facilities. – Prior to initiating modeling efforts for the 2015 IRP, determine a multi-state "total resource cost test" evaluation methodology to address regulatory recovery among states with identified capital expenditures. – Prior to initiating modeling efforts for the 2015 IRP, present to IRP stakeholders in a public input meeting the Company's recommended approach to analyzing cost effective production efficiency resources in the 2015 IRP.
Action Item	**7. Demand Side Management (DSM) Actions**
7a.	**<u>Class 2 DSM</u>** • Acquire 1,425 – 1,876 GWh of cost-effective Class 2 energy efficiency resources by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017. – Collaborate with the Energy Trust of Oregon on a pilot residential home comparison report program to be offered to Pacific Power customers in 2013 and 2014. At the conclusion of the pilot program and the associated impact

evaluation, assess further expansion of the program.

- Implement an enhanced consolidated business program to increase DSM acquisition from business customers in all states excluding Oregon.
  - Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013.
  - Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014.
  - Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014.
- Accelerate to the 2nd quarter of 2014, an evaluation of waste heat to power where generation is used to offset customer requirements – investigate how to integrate opportunities into the DSM portfolio.
- Increase acquisitions from business customers through prescriptive measures by expanding the "Trade Ally Network".
  - Base case target in all states is 3rd quarter 2014, with an accelerated target of 4th quarter 2013
- Accelerate small-mid market business DSM acquisitions by contracting with third party administrators to facilitate greater acquisitions by increasing marketing, outreach, and management of comprehensive custom projects by 1st quarter 2014.
- Increase the reach and effectiveness of "express" or "typical" measure offerings by increasing qualifying measures, reviewing and realigning incentives, implementing a direct install feature for small commercial customers, and expanding the residential refrigerator and freezer recycling program to include commercial units.
  - Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013.
  - Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014.
  - Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014.
- Increase the reach of behavioral DSM programs:
  - Evaluate and expand the residential behavioral pilot.
    - Utah base case schedule is 2nd quarter 2014, with an accelerated target of 4th quarter 2013.
  - Accelerate commercial behavioral pilot to the end of the first quarter 2014.
  - Expand residential programs system-wide pending evaluation results.
    - System-wide target is 3rd quarter 2015, with an accelerated target of 3rd quarter 2014.
- Increase acquisition of residential DSM resources:
  - Implement cost effective direct install options by the end of 2013.
  - Expand offering of "bundled" measure incentives by the end of 2013.
  - Increase qualifying measures by the end of 2013.
  - Review and realign incentives.
    - Utah schedule is 1st quarter 2014

	♦ Washington base case schedule is 2nd quarter 2014, with accelerated target of 1st quarter 2014. ♦ Wyoming, California, and Idaho base case schedule is 3rd quarter 2014, with an accelerated target of 2nd quarter 2014 – Accelerate acquisitions by expanding refrigerator and freezer recycling to incorporate retail appliance distributors and commercial units – 3rd quarter 2013. – By the end of 2013, complete review of the impact of accelerated DSM on Oregon and the Energy Trust of Oregon, and re-contract in 2014 for appropriate funding as required. – Include in the 2013 IRP Update Class 2 DSM decrement values based upon accelerated acquisition of DSM resources. – Include in the 2014 conservation potential study an analysis testing assumptions in support of accelerating acquisition of cost-effective Class 2 DSM resources, and apply findings from this analysis into the development of candidate portfolios in the 2015 IRP.
7b.	**Class 3 DSM** • Develop a pilot program in Oregon for a Class 3 irrigation time-of-use program as an alternative approach to a Class 1 irrigation load control program for managing irrigation loads in the west. The pilot program will be developed for the 2014 irrigation season and findings will be reported in the 2015 IRP.
Action Item	**8. Coal Resource Actions**
8a.	**Naughton Unit 3** • Continue permitting and development efforts in support of the Naughton Unit 3 natural gas conversion project. The permit application requesting operation on coal through year-end 2017 is currently under review by the Wyoming Department of Environmental Quality, Air Quality Division. • Issue a request for proposal to procure gas transportation for the Naughton plant as required to support compliance with the conversion date that will be established during the permitting process. • Issue an RFP for engineering, procurement, and construction of the Naughton Unit 3 natural gas retrofit as required to support compliance with the conversion date that will be established during the permitting process.
8b.	**Hunter Unit 1** • Complete installation of the baghouse conversion and low NO_X burner compliance projects at Hunter Unit 1 as required by the end of 2014.
8c.	**Jim Bridger Units 3 and 4** • Complete installation of selective catalytic reduction (SCR) compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4 as required by the end of 2015 and 2016, respectively.

8d.	**<u>Cholla Unit 4</u>** • Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency's Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives in the 2013 IRP Update.
Action Item	**9. Transmission Actions**
9a.	**<u>System Operational and Reliability Benefits Tool (SBT)</u>** • 60 days after filing the 2013 IRP, establish a stakeholder group and schedule workshops to further review the System Benefit Tool (SBT). – For the 2013 IRP Update, complete additional analysis of the Energy Gateway West Segment D that evaluates staging implementation of Segment D by sub-segment. – In preparation for the 2015 IRP, continue to refine the SBT for Energy Gateway West Segment D and develop SBT analyses for additional Energy Gateway segments.
9b.	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: – Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – Segment D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach projected through the next 2 to 4 years. – Segment H Cascade Crossing, complete benefits analysis in 2013. – Segment H Boardman to Hemingway, continue to support the project under the conditions of the Boardman to Hemingway Transmission. Project Joint Permit Funding Agreement, projected through 2015.
9c.	**<u>Sigurd to Red Butte 345 kilovolt Transmission Line</u>** • Complete project construction per plan.
Action Item	**10. Planning Reserve Margin Actions**
10a.	**<u>Planning Reserve Margin</u>** • Continue to evaluate in the 2015 IRP the results of a System Optimizer portfolio sensitivity analysis comparing a range of planning reserve margins considering both cost and reliability impacts of different levels of planning reserve

	margin assumptions. Complete for the 2015 IRP an updated planning reserve margin analysis that is shared with stakeholders during the public process.
Action Item	**11. Planning and Modeling Process Improvement Actions**
11a.	**<u>Modeling and Process</u>** • Within 90 days of filing the 2013 IRP, schedule an IRP workshop with stakeholders to discuss potential process improvements that can more efficiently achieve meaningful cost and risk analysis of resource plans in the context of the IRP and implement process improvements in the 2015 IRP.
11b.	**<u>Cost/Benefit Analysis of DSM Resource Alternatives</u>** • Complete a cost/benefit analysis on the level of detail used to evaluate prospective DSM resources in the IRP. The analysis will consider the tradeoffs between model run-time and resulting resource selections, will be shared with stakeholders early in the 2015 IRP public process, and will inform how prospective DSM resources will be aggregated in developing resource portfolios for the 2015 IRP.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, Request for a General Rate Revision	**UE 374**

Sierra Club Hearing Reference Materials

Cross Examination of Mr. James Owen

September 2, 2020

Sierra Club Reference Materials: Owen Cross Examination

Exhibit No.	**Description**	**Pages Referenced**	**Confidential (Yes/No)**
Sierra Club/700	WA UTC Exhibit CAT-21C, April 24, 2013 SCR Memorandum	Entire document	Yes
Sierra Club/119	Highly Confidential Exhibit B Re: Bridger EPC Contract 9-Page Excerpt	Entire document	Yes (HC)
PAC/2504	Public Letter from PacifiCorp Energy's William K. Lawson to Wyoming DEQ's David Finley (Jan. 29, 2009)	Entire document	No
Sierra Club/410	Confidential Letter from PacifiCorp Energy's William K. Lawson to Wyoming DEQ's David Finley (Jan. 29, 2009)	Entire document	Yes
Sierra Club/105	WY DEQ Bart Appeal Settlement Agreement (November 2010)	Entire document	No
Sierra Club/411	Confidential UE 246 Exhibit Sierra Club/114, 2003 PacifiCorp Control Report	Fisher/1-6	Yes
Sierra Club/412	Confidential UE 246 Exhibit Sierra Club/115, Air Quality Reference Case Investments 2005	Fisher/1-4	Yes
Sierra Club/403	Selected Public Data Responses	Fisher/9-10 (DR 8.3 – 1st Supp.)	No
Sierra Club/721	Confidential Attachments to PacifiCorp Response to Sierra Club 8.3 - 1st supp.		Yes
	UE 246 - Order No. 12-493	25-30	No
PAC/2500	Reply Testimony of James Owen	Entire document	Yes
PAC/4000	Surrebuttal Testimony of James Owen	Entire document	Yes

Table of Contents of Provided Materials

Docket No. UE 374
Exhibit PAC/2504
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of James Owen

PacifiCorp Letter to Wyoming BART Determinations and Regional Haze SIP

June 2020

PACIFICORP ENERGY
A DIVISION OF PACIFICORP

William Lawson
Director, Environmental Department
1407 West North Temple, Suite 330
Salt Lake City, Utah 84116
801.220.4581 (Office)
801.220.2094 (Fax)

RECEIVED FEB 2009 AIR QUALITY DIVISION

January 29, 2009

Mr. David Finley
Wyoming Division of Air Quality
Herschler Building
122 W. 25th Street
Cheyenne, Wyoming 82002

Re: PacifiCorp -- Wyoming BART Determinations and Regional Haze SIP

Dear Mr. Finley,

You have requested that PacifiCorp provide additional support regarding its proposed BART determinations for NO_x emissions at Jim Bridger units 1 – 4 and Naughton unit 3.[1] The information contained in this letter is intended to elaborate on PacifiCorp's BART analyses, which already have been filed with WDAQ for these units.

I. Executive Summary

This letter focuses solely on the proper BART emission limit for NO_x at Naughton unit 3 and the Jim Bridger units. PacifiCorp's individual BART applications for each of these units contain a proposed BART emission limit which can be achieved through the installation of combustion controls such as low-NO_x burners (LNB) and overfire air (OFA). This is appropriate and consistent with the guidance and requirements set forth in "Appendix Y" of EPA's Regional Haze Regulations and Guidelines for Best Available Retrofit Technology; Final Rule ("Regional Haze Rules"), as those are incorporated into Wyoming's state regulations. This is also consistent with the preamble which accompanies Appendix Y and the Regional Haze Rules (the "Preamble"). *See* 70 FR 39104.

Appendix Y references "presumptive BART" emission rates which vary based on boiler design and coal type. To the extent the presumptive BART NO_x emission rates are relevant to Naughton unit 3 and the Jim Bridger units, it is important to note that the coal burned at these units is more comparable to bituminous than subbituminous (as the coal classification relates to NO_x emissions). Correctly assuming that these units burn coal

[1] This letter does not address any of the other PacifiCorp BART-eligible units in Wyoming nor is it intended as a comprehensive list of comments PacifiCorp may choose to make in regard to WDAQ's upcoming BART determinations for the PacifiCorp units.

with bituminous-like NO_x emissions leads to a presumptive BART emission limit for NO_x of 0.28 lb/MMBtu. This presumptive BART emission limit, however, is not the end of the analysis for any of the units, but only serves as a guide against which the calculated BART emission limit can be compared.

Based on a variety of other factors as described herein and in the underlying BART applications, PacifiCorp continues to recommend that assigning a calculated 30-day rolling average BART emission limit for NO_x of 0.26 lb/MMBtu for the Jim Bridger units is appropriate, including the installation of LNB and OFA as the proper BART control technology. Also, assigning a calculated 30-day rolling average BART emission limit for NO_x of 0.35 lb/MMBtu for Naughton unit 3 likewise is appropriate, including the installation of LNB and OFA as the proper BART control technology.

II. Background

In its BART applications for each unit covered by this letter, PacifiCorp and its consultant worked closely with WDAQ staff before submitting detailed BART engineering analyses for Naughton unit 3 and the Jim Bridger units. These analyses resulted in the proposed BART NO_x emission limits and control technologies listed below in Table 1:

Table 1

Unit	Proposed Rate	Proposed Control Technology
Naughton 3	0.35 lb/MMBtu	tune existing LNB and over-fire air system
Jim Bridger 1	0.26 lb/MMBtu	add LNB with separated over-fire air
Jim Bridger 2	0.26 lb/MMBtu	already added LNB with separated over-fire air
Jim Bridger 3	0.26 lb/MMBtu	add LNB with separated over-fire air
Jim Bridger 4	0.26 lb/MMBtu	add LNB with separated over-fire air

In lieu of the above proposed rates, some may argue that WDAQ should instead impose the presumptive BART rate (found in Appendix Y) for tangentially-fired boilers burning subbituminous coal. This rate is 0.15 lb/MMBtu. To the extent this presumptive BART rate is applied, some may argue further that WDAQ should require the installation of SCR as the appropriate BART control technology in order to achieve this NO_x emissions rate. As explained below, however, neither the facts nor the applicable BART requirements support these arguments.

To the contrary, as noted in PacifiCorp's BART applications, and as further explained herein: (i) applying the presumptive BART rate of 0.15 lb/MMBtu for subbituminous coal at these units is not appropriate; and (ii) requiring the installation of SCR at these units likewise is not an appropriate BART control technology.

III. Based on Proper Coal Classification, the "Presumptive" BART NO_x Limit for Naughton Unit 3 and the Jim Bridger Units is 0.28 lb/MMBtu

As explained herein and in the BART applications, to the extent a presumptive BART emission limit (as found in Appendix Y) is relevant, then the appropriate presumptive BART limit for NO_x at Naughton unit 3 and the Jim Bridger units is 0.28 lb/MMBtu.

Presumptive BART

The Preamble to the BART rules observes that "States, as a general matter, must require owners and operators of greater than 750 MW power plants to meet [presumptive] BART limits."[2] 70 FR 39104, 39131. The Preamble goes on to say, however that "a State may establish different requirements if the State can demonstrate that an alternative determination is justified based on consideration of the five statutory factors." *Id.* Specific to NO_x emission limits, the Preamble notes that, "the NO_x limits set forth here today are presumptions only; in making a BART determination, States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." Id at 39134.

By rule, Wyoming follows Appendix Y in determining the proper BART NO_x emission limits for electric generating units (EGUs). Wyo. Reg., Chap. 6, Sec. 9(c). The presumptive BART NO_x emission limits listed in Appendix Y are "differentiated by boiler design and type of coal burned." *See* 40 CFR Part 51, Appendix Y, IV.E.5. As noted above, the presumptive BART NO_x emission limit (for EGUs with tangentially fired boilers) is 0.15 lb/MMBtu for coal ranked as subbituminous. For coal ranked as bituminous, the presumptive BART NOx emission limit (for EGUs with tangentially fired boilers) is 0.28 lb/MMBtu.[3] *Id.* EPA readily acknowledges that these presumptive NO_x emission limits are based on many assumptions and also that, if one of these assumptions does not apply to a particular unit, it may affect the cost-effectiveness of the presumptive limit.[4]

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[2] The Jim Bridger power plant exceeds 750 MW in total capacity; the Naughton power plant does not.

[3] Even though the Wyoming rules distinguish – based on the amount of generating capacity – between whether Appendix Y "shall" apply or be used merely as "guidance," Appendix Y itself applies the same presumptive NO_x emission limit regardless of facility generating size. "For coal-fired EGUs greater than 200 MW located at greater than 750 MW power plants and operating without post combustion controls [i.e., Jim Bridger units]. . . , we have provided presumptive NO_x limits differentiated by boiler design and type of coal burned . . . . For coal-fired EGUs greater than 200 MW located at power plants 750 MW or less in size and operating without post-combustion controls [i.e., Naughton unit 3], you should likewise assume that these same levels are cost effective. You should require such utility boilers to meet the following NO_x limits, unless you determine that an alternative control limit is justified . . . ." 70 FR 39171.

[4] "The following NO_x emission rates were determined based on a number of assumptions, including that the EGU boiler has enough volume to allow for installation and effective operation of separated overfire air ports. For boilers where these assumptions are incorrect, these emission limits may not be cost-effective." 70 FR 39171.

Coal Classification

Given the large disparity between the presumptive NO_x emission limits for subbituminous and bituminous coals, it is very important to assign the proper coal classification when considering an individual unit. This is particularly true where, as is the case with Naughton unit 3 and the Jim Bridger units, the use of one coal quality classification results in a significantly different presumptive BART rate as compared to another coal classification.

In the Preamble, EPA recognized "that, unlike the methods for controlling SO_2 (which fall within a fairly narrow range of cost effectiveness and control efficiencies), the removal efficiencies and costs associated with the control techniques for NO_x vary considerably, depending on the design of the boiler and the type of coal used." 70 FR 39104, 39134. Also, in that same section of the preamble, EPA recognized that "both cost effectiveness and post-control rates for NO_x do depend largely on boiler design and type of coal burned." *Id.* Therefore, to the extent presumptive BART rates are relevant; the BART analysis for Naughton unit 3 and the Jim Bridger units should carefully consider "the type of coal burned."

Unfortunately, neither Appendix Y, the Preamble, nor the Regional Haze Rules provide a standard or guidance to determine the appropriate coal classification. Instead, Appendix Y simply presumes that coal types are easily classified with a clear distinction between the various coals. This presumption, however, is not correct and certainly should not be the sole basis for assuming that the presumptive NO_x emission rate of 0.15 lb/MMBtu is applicable to Naughton unit 3 and the Jim Bridger units. Indeed, a review of the literature shows that coal types are only loosely defined along a sliding scale, meaning that no bright line distinction between types of coal exists.

Because coal classification is of such fundamental importance in selecting the proper presumptive BART rate, PacifiCorp included in its BART applications an explanation of why the coal burned at Naughton unit 3 and the Jim Bridger units should be considered to be bituminous for the purpose of considering presumptive BART limits for NO_x. In addition, PacifiCorp has attached to this letter a technical memorandum prepared by CH2M Hill entitled "Coal Quality and Nitrogen Oxide Formation" (the "Coal Quality Technical Memo"), which discusses this coal classification issue in more detail. The attached memorandum is intended to amplify similar information provided in the BART applications for these units.

Jim Bridger Units/Naughton Unit 3 Coal Classification

As the Coal Quality Technical Memo explains, a detailed analysis of the key coal characteristics that relate to the formation of NO_x emissions supports the conclusion that the Jim Bridger units and Naughton unit 3 coals should be considered as bituminous for the purpose of applying a presumptive BART NO_x emission limit. This conclusion alone supports presumptive BART limits based on bituminous coal.

As an additional reason, and as explained in the Coal Quality Technical Memo, most coals from the Powder River Basin ("PRB") are classified as subbituminous C and demonstrate high-reactivity and low-NO_x production characteristics. It is against this backdrop of already low NO_x emissions typically associated with PRB subbituminous coal that EPA selected the very low presumptive NOx emission rate of 0.15 lb/MMBtu for tangentially fired boilers (like those at Naughton unit 3 and the Jim Bridger units) and assumed that this rate could be achieved by combustion controls like LNB and OFA. In reaching this conclusion, however, EPA assumed that PRB subbituminous C coals to represent the entire class of subbituminous coals in use across the country since the PRB coals make up the largest share of such coals. However, there are other types of subbituminous coals that occur outside of the PRB that are not as reactive and low NOx forming as the PRB coals. EPA's general assumptions regarding NO_x emissions and subbituminous coals, therefore, fail to recognize that non-PRB subbituminous coals could have higher NO_x emissions than PRB subbituminous C coals. This, in turn, affects the feasibility and cost effectiveness of the presumptive BART NO_x emission limits (as stated in Appendix Y) for boilers using non-PRB subbituminous coal like Naughton unit 3 and the Jim Bridger units.

In other words, with NO_x emissions from PRB subbituminous coal already low compared to other types of coal, EPA apparently believes it is a technologically easy and cost-effective step to impose an even lower presumptive BART emission rate of 0.15 lb/MMBtu (for tangentially fired boilers), which can be achieved by adding combustion controls like LNB and OFA. However, for non-PRB subbituminous coals, it is not such an easy and cost-effective step because combustion controls typically will not be enough to control NO_x emissions to this rate. In this light, EPA's presumed feasibility and cost-effectiveness falls apart because very expensive and impractical post-combustion controls become part of the BART equation for certain subbituminous (non-PRB) coals.

The Coal Quality Technical Memo concludes as follows:

> "For all these reasons, the [Naughton unit 3 and Jim Bridger units] coals . . . are more similar in their NO_x formation potential to bituminous coals than to subbituminous coals such as PRB. Therefore, the presumptive BART limit that should be considered for the Jim Bridger [units] and Naughton [unit 3] . . . should be closer to 0.28 lb/MMBtu presumptive BART limit rather than the subbituminous 0.15 lb/MMBtu limit."

Considering the presumptive BART NO_x emission limit for bituminous coal for Naughton unit 3 and the Jim Bridger units not only complies with the requirements of

Wyoming law (including Appendix Y), but is more stringent than BART limits imposed on other Wyoming sources.[5]

Coal Classification In Other States

The coal classification issue discussed above in regard to presumptive BART limits is not unique to PacifiCorp's units or the state of Wyoming. The State of New Mexico is addressing a similar issue concerning the San Juan Generating Station (SJGS).

In New Mexico, the SJGS argues that it cannot meet the presumptive BART NO_x emissions limit of 0.23 lb/MMBtu (for a dry bottom, wall-fired boiler) for subbituminous coal. Using this presumptive BART limit was problematic because the local New Mexico coal used by SJGS fit into a "gray area" between bituminous and sub-bituminous coal. *See* "Discussion of SJGS Coal Ranking for BART NO_x Presumptive Limit Determination." The SJGS coal was less volatile, and has less oxygen and moisture, than the characteristics of PRB subbituminous coals used in developing the presumptive BART NO_x emission limits under Appendix Y. *Id.* As the SJGS explains, "with respect to NO_x combustion control performance, SJGS coal behaves more like a bituminous coal."[6] *Id.*

The same can be said of the Jim Bridger units and Naughton unit 3 coals. Therefore, if a presumptive NO_x emissions limit is considered for any of these units, PacifiCorp urges WDAQ to take account of the applicable coal characteristics and properly assume that the Jim Bridger units and Naughton unit 3 coals are closer to bituminous in composition than subbituminous. This proper assumption, in turn, leads to the conclusion that if a presumptive BART NO_x emission limit is considered for any of these units, it should be at the 0.28 lb/MMBtu rate presumed for bituminous coal. As explained in the following section, however, the calculated BART emission rates noted in Table I above should control over the presumptive BART rates in any event.

IV. The Five Factor Analysis Also Indicates SCR Is Not Appropriate

[5] For example, Wyoming has proposed higher NO_x emissions rates for other coal fired boilers in Wyoming. When making the BART determination for FMC's Westvaco facility, Wyoming determined that a NO_x emissions rate of 0.35 lb/MBTU was BART. *See* August 4, 2008 BART Application Analysis, AP 6045, pg. 30. Additionally, Wyoming approved a BART NO_x emissions rate of 0.49 lb/MBTU for General Chemical's two coal fired boilers at its Green River Works facility. *See* August 4, 2008 BART Application Analysis, AP 6046, pg. 26. PacifiCorp's proposed "presumptive" BART limit of 0.28 lb/MBTU for the Naughton and Jim Bridger power plants is much lower than these sources.

[6] The BART NO_x emission limit proposed by the New Mexico Environment Department for the SJGS is 0.293 lb/MMBtu. This is consistent with the limit established in a consent decree concerning the plant which is unrelated to the BART determination. For information concerning SJGS BART issues, see http://www.nmenv.state.nm.us/aqb/reghaz/documents/COMPLETEFinalDiscussionofSJGSCoalClassificationRevisi.pdf

Establishing the appropriate presumptive BART NO_x emission limit as described above is only one consideration in making a proper BART determination. Indeed, if an analysis of the five statutory factors supports a different emissions limit, then the presumptive BART rates take on a role only as a non-binding guide or marker for units like Naughton unit 3 and the Jim Bridger units.

Five Factor Analysis and Proposed BART Limits

As noted, the presumptive BART limits are exactly what they purport to be – presumptions that can be rebutted and modified based on additional case by case information. In the Preamble, EPA states that its "presumption accordingly may not be appropriate for all sources. As noted, the NO_x limits set forth here today are presumptions only; in making a BART determination, States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." 70 FR 39134. Appendix Y further explains that a state "may determine that an alternative control level is appropriate based on a careful consideration of the [five] statutory factors," particularly for boilers where EPA's assumptions related to NO_x emissions rates are incorrect. *See* Appendix Y, IV.E.5.

PacifiCorp already has submitted a detailed five factor analysis for Naughton unit 3 and the Jim Bridger units in their individual BART applications. The final result of this analysis is a proposed BART emission limit for NOx at Naughton unit 3 of 0.35 lb/MMBtu – higher than the presumptive BART limit of 0.28 lb/MMBtu. As for the Jim Bridger units, the result of the analysis is a NOx limit of 0.26 lb/MMBtu – lower than the presumptive BART limit. In each case; however, the proposed BART limits can be met by the installation of combustion controls. Imposing lower NO_x limits than PacifiCorp has proposed would require the installation of post-combustion controls such as SCR, which is contrary to applicable BART requirements because the "cost of compliance" would be too high.

Cost of Compliance

Focusing on the cost of compliance factor, EPA assumes in the Preamble that approximately 75% of the EGUs would have BART NO_x removal costs between \$100 and \$1,000 per ton, and that almost all of the remaining EGUs could install sufficient combustion control technology for less than \$1,500 per ton:

> "The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over \$100 to \$1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air

> ("ROFA"), which has already been demonstrated on a variety of coal-fired units.[7] Based on the data before us, the costs of such controls in most cases are less than $1500 per ton." 70 FR 39135.

EPA's assumptions regarding the cost of controls place Naughton unit 3 or the Jim Bridger units outside the scope of expected removal costs when considering the lower presumptive limit of 0.15 lb/MMBtu. As indicated in the BART applications, these units can only meet this rate by installing SCR. Under this scenario, the incremental control costs per ton would approach $4,000 per ton, well above the presumed control cost range included in the Preamble.

It is for this reason that EPA stated further in the Preamble that SCR generally is not cost effective for EGUs (except for cyclone boilers):

> "We also analyzed the installation of SCRs at BART-eligible EGUs, applying SCR to each unit and fuel type. The cost-effectiveness was generally higher than for current combustion control technology except for one unit type, cyclone units. Because of the relatively high NO_x emission rates of cyclone units, SCR is more cost-effective. Our analysis indicated that the cost-effectiveness of applying SCR on coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton. As a result, we are establishing a presumptive NO_x limit for cyclone units based on the use of SCR. For other units, we are not establishing presumptive limits based on the installation of SCR. Although States may in specific cases find that the use of SCR is appropriate, *we have not determined that SCR is generally cost-effective for BART across unit types*." 70 FR 39135-36. (Emphasis supplied)

V. LNB /OFA Are the Proper BART Control Technology; SCR is Not

Unlike SCR, LNB/OFA is the proper BART control technology for Naughton unit 3 and the Jim Bridger units.

A "BART" determination involves not only the setting of an emissions limit, but also the selection of a particular emissions control technology, or group of technologies, to achieve that limit. Wyoming's BART rules refer to this as "control equipment", "control technology", and "BART technology." Wyo. Reg., Chp. 6, Sec. 9(e)(i)(E), Sec. 9(e)(iii) and (e)(viii). Regardless of the term used, and as explained above, the Preamble and other guidance are clear that LNBs and OFA are intended to be the "BART technology" for the tangentially fired boilers such as Naughton unit 3, the Jim Bridger units, and other similarly situated units.

[7] The BART applications for Naughton unit 3 and the Jim Bridger units explain why ROFA is not a workable alternative for those units.

In the Preamble, EPA stated that, except for cyclone boilers, the "types of current combustion control technology options assumed include low NOx burners, over-fire air, and coal reburning." 70 FR 39134; *see also* 39144 ("For all other coal-fired units, our analysis assumed these units will install current combustion control technology."). In fact, in the Technical Support Document used to develop the presumptive BART NO_x emissions limits, EPA explained that the "methodology EPA used in applying current combustion control technology to BART-eligible EGUs" included applying "a complete set of combustion controls. A complete set of combustion controls for most units includes a low NO_x burner and over-fire air." See, "Technical Support Document, Methodology for Developing NO_x Presumptive Limits," EPA Clean Air Markets Division, pg. 1 (dated June 15, 2005).

The Preamble identifies post-combustion controls for NO_x, such as SCR and SNCR, as "BART technology" for only "cyclone" units. EPA made it clear that for "other units, we are not establishing presumptive limits based on the installation of SCR." 70 FR 39136. Therefore, EPA's presumptive "BART technology" is LNBs and some type of OFA. EPA further elaborated in the preamble on the SCR costs, stating that although "States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types." *Id.*

Other BART eligible sources in Wyoming have determined that LNBs and/or OFA are "BART technology," and that SCR would not be appropriate. For example, after additional analysis and study, Basin Electric recently submitted its analysis that OFA was the appropriate BART technology for the Laramie River Station and that SCRs were not "BART" due to several factors, including the high cost and relatively low visibility improvement. *See* Basin Electric/Laramie River Station Refined BART Visibility Modeling, pages 13 and 14 (submitted July 24, 2008).

Similarly, the State of Wyoming also determined that LNBs and OFA were BART for the coal-fueled boilers at FMC's Westvaco facility and at General Chemical's Green River Works facility. *See* August 4, 2008 BART Application Analysis, AP 6045, pg. 30, and August 4, 2008 BART Application Analysis, AP 6046, pg. 26. All of these BART analyses reviewed SCR and SNCR, but none of them found that SNCR or SCR are BART for any of these facilities. Likewise, LNBs and OFA should be determined to be BART technology for PacifiCorp's Jim Bridger and Naughton EGUs.

A recent survey of the western states indicates that no states have mandated SCR or SNCR as "BART technology" for any EGUs. For example, in Colorado's recent BART determinations, Colorado recognized LNBs and OFA (or some modification of the same) as BART for 14 different EGUs. *See* Colorado's Air Quality Regulations, Part F, IV.D. In fact, consistent with PacifiCorp's position explained above, Colorado believes that Appendix Y and the preamble do not allow post-combustion control, such as SCRs, to be considered at all as "BART technology." In a letter addressing BART issues, Colorado's Air Quality Division explained that "Colorado's BART rule does not allow for post combustion NOx controls. This provision is based upon the preamble to the final EPA

BART rule and Appendix Y." *See* January 11, 2008 letter to Vickie Patton from Colorado Division of Air Quality, pg. 3.

Additionally, the Oregon Department of Environmental Quality, in the August 20, 2008, BART determination for the Boardman power plant, found that SCR was not BART technology and stated that the "capital cost of [SCR] is 7 times that of new low NOx burners with modified overfire air system." PacifiCorp's BART applications confirm that SCR is not cost-effective or otherwise appropriate for Naughton unit 3 or the Jim Bridger units. Therefore, Wyoming, like other western states that have considered the issue, should determine that BART technology for PacifiCorp's Jim Bridger and Naughton power plants is LNBs and OFA, and not SCR or SNCR.

VI. Conclusion

Based on a close examination of the characteristics of coal burned Naughton unit 3 and the Bridger units, it is clear that the appropriate presumptive BART NO_x emission rate for consideration at these units is 0.28 lb/MMBtu. The appropriate calculated NO_x emission rate, however, is 0.35 lb/MMBtu for Naughton unit 3 (30 day rolling average) and 0.26 lb/MMBtu for the Bridger units (30 day rolling average). The appropriate control technology to achieve these rates is LNB and OFA.

Please feel free to contact us with any questions.

Sincerely,

William K. Lawson

William K. Lawson
Director, Environmental Services

cc: Idaho Power

Docket No. UE 374
Exhibit Sierra Club/105
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 105

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

WY DEQ Bart Appeal Settlement Agreement

BART APPEAL SETTLEMENT AGREEMENT

The Wyoming Department of Environmental Quality, Air Quality Division (the "DEQ/AQD") and PacifiCorp Energy, a division of PacifiCorp ("PacifiCorp"), enter into this BART Appeal Settlement Agreement (the "Settlement Agreement") to fully and finally resolve PacifiCorp's appeal before the Wyoming Environmental Quality Council (the "EQC") in Docket No. 10-2801 wherein PacifiCorp challenged certain conditions of BART permit Nos. MD-6040 and MD-6042 for the Jim Bridger and Naughton power plants. The DEQ/AQD and PacifiCorp are collectively referred to herein as the "Parties" and sometimes individually as "Party." The Settlement Agreement shall be effective between the Parties on the date that the last signature is affixed below (the "Effective Date"), conditioned on approval by the EQC as described herein.

Wyo. Stat. 16-3-107(n) and Chapter I, § 11 of the DEQ's Rules of Practice & Procedure provide for the disposition of this contested case by stipulation of the Parties upon approval by the EQC. Additionally, Wyo. Stat § 35-11-112 empowers the EQC to order the modification of BART Permit Nos. MD-6040 and MD-6042 to resolve this contested case. To that end, PacifiCorp and the DEQ/AQD, conditioned on the approval of the EQC, hereby stipulate and agree as follows.

1. **Background:** As part of its obligation under the Clean Air Act's Regional Haze Program, the State of Wyoming, through the DEQ/AQD, promulgated regulations requiring the installation of Best Available Retrofit Technology ("BART") on certain eligible facilities. PacifiCorp timely complied with these regulations by filing applications for BART permits for its eligible facilities, including an application for its Bridger power plant on January 16, 2007, and its Naughton power plant on February 12, 2007. PacifiCorp further filed additional information with the DEQ/AQD relating to these applications. Following public notice and comment, and public hearings, the DEQ/AQD issued BART permit Nos. MD-6040 for the Bridger power plant and MD-6042 for the Naughton power plant on December 31, 2009. On February 26, 2010, PacifiCorp timely filed an appeal to the EQC of certain provisions in BART permit Nos. MD-6040 and MD-6042. Litigation ensued, including discovery and motion practice. This Settlement Agreement resolves all issues raised in that litigation. Also, in connection with this Settlement Agreement, PacifiCorp has provided to DEQ/AQD the information attached as Exhibit A which the parties intend to be used in the Wyoming Regional Haze SIP as that term is described below.

2. **Definitions:** As used in this Agreement, the following terms are defined as:

   "BART Permit Appeal" means: PacifiCorp's Appeal and Petition for Review of BART Permits regarding the Bridger BART Permit and the Naughton BART Permit, referred to as Docket No. 10-2801, before the EQC.

   "BART Appeals Arguments" means: The arguments raised by PacifiCorp in the BART Permit Appeal, including its Motion for Partial Summary Judgment and supporting Memorandum, filed June 30, 2010, and its Reply in Support of Its Motion for Partial Summary Judgment, filed August 31, 2010.

"Naughton BART Permit" means: BART permit No. MD-6042 as issued by the DEQ/AQD on December 31, 2009.

"Bridger BART Permit" means: BART permit No. MD-6040 as issued by the DEQ/AQD on December 31, 2009.

"Wyoming Regional Haze SIP" means: the final version of the Wyoming State Implementation Plan regarding "regional haze" and addressing regional haze requirements for Wyoming mandatory Class 1 areas under 40 CFR §51.309(g) as prepared by the DEQ/AQD and submitted to EPA for review and approval. As of the date of this Settlement Agreement, the DEQ/AQD has not completed the final version of the Wyoming Regional Haze SIP and instead has prepared a draft of that document dated August 25, 2009, which DEQ/AQD released previously for public comment. Based in part on those comments, DEQ/AQD intends to release an updated version of the draft Wyoming Regional Haze SIP for additional public comment before the end of 2010.

3. **Agreement:** The Parties have engaged in negotiations to reach a settled resolution to this contested case. The Parties have agreed, upon the terms contained herein, to settle and compromise PacifiCorp's BART Permit Appeal, including the BART Appeals Arguments.

4. **Performance by PacifiCorp:** In reliance upon the releases, agreements, and representations of the DEQ/AQD in this Settlement Agreement, and conditioned upon the EQC's approval of this Settlement Agreement and its terms, PacifiCorp shall do the following:

(a) Naughton - PacifiCorp shall withdraw its BART Appeals Arguments regarding the Naughton power plant, dismiss its BART Permit Appeal as it relates to the Naughton power plant, and agree to abide by the terms of the Naughton BART Permit;

(b) Bridger - PacifiCorp shall withdraw its BART Appeals Arguments regarding the Bridger power plant, dismiss its BART Permit Appeal as it relates to the Bridger power plant, and agree to abide the terms of the Bridger BART Permit as modified by the EQC in accordance with this Settlement Agreement, including the removal of Conditions 17 and 18;

(c) NOx Control for Bridger Units 3 and 4 – With respect to Bridger Units 3 and 4, PacifiCorp shall: (i) install SCR; (ii) install alternative add-on NOx control systems; or (iii) otherwise reduce NOx emissions to achieve a 0.07 lb/mmBtu 30-day rolling average NOx emissions rate. These installations shall occur, and/or this emission rate will be achieved, on Unit 3 prior to

December 31, 2015 and Unit 4 prior to December 31, 2016. These installations shall occur, and/or this emission rate will be achieved, in conjunction with PacifiCorp's planned overhaul schedule for these units and pursuant to a construction or other permit application to be submitted by PacifiCorp to AQD no later than December 31, 2012; and

(d) NOx Control for Bridger Units 1 and 2 -- With respect to Bridger Units 1 and 2, PacifiCorp shall: (i) install SCR; (ii) install alternative add-on NOx control systems; or (iii) otherwise reduce NOx emissions not to exceed a 0.07 lb/mmBtu 30-day rolling average NOx emissions rate. These installations shall occur, and/or this emission rate will be achieved, on Unit 2 prior to December 31, 2021 and Unit 1 prior to December 31, 2022. These installations shall occur, and/or this emission rate will be achieved, in conjunction with PacifiCorp's planned overhaul schedule for these units and pursuant to a construction or other permit application to be submitted by PacifiCorp to AQD no later than December 31, 2017.

5. **Performance by the DEQ/AQD:** In reliance upon the releases, agreements and representations of PacifiCorp in this Settlement Agreement, and conditioned upon the EQC's approval of this Settlement Agreement and its terms, the DEQ/AQD shall do the following:

(a) Naughton – The DEQ/AQD shall, pursuant to an order by the EQC approving this Settlement Agreement, include in the Wyoming Regional Haze SIP a statement explaining that the cost of the Naughton Unit 3 baghouse is reasonable when considering all factors relating to the existing PM controls in addition to those considered during the BART analysis.

(b) Bridger – The DEQ/AQD shall, pursuant to an order by the EQC approving this Settlement Agreement, delete Conditions 17 and 18 from the Bridger BART Permit and, in lieu of Conditions 17 and 18, adopt the requirements of paragraphs 4(c) and 4(d) of this Settlement Agreement into the Wyoming Regional Haze SIP as part of Wyoming's Long-Term Strategy and/or Reasonable Progress Goals; and

(c) PacifiCorp's Compliance with BART and LTS Requirements - The DEQ/AQD shall not require further PM or NOx reductions at Naughton Unit 3, or require further NOx reductions at Bridger Units 1 – 4, for purposes of meeting BART, Long-Term Strategy requirements and/or Reasonable Progress Goals in the Wyoming Regional Haze SIP through 2023.

6. **Conditions of Settlement:** The Parties' duties, rights and obligations of this Settlement Agreement are conditioned upon, and the Parties shall in good faith cooperate to achieve, the following:

(a) The EQC and any other required Wyoming governing authority must approve this Settlement Agreement and its terms;

(b) PacifiCorp and the DEQ/AQD must file a joint stipulated motion with the EQC requesting dismissal of PacifiCorp's BART Permit Appeal, and the EQC must dismiss the BART Permit Appeal on approval of the terms contained herein subject only to EQC's continuing jurisdiction as described in Section 7 below;

(c) The EQC must order the Bridger BART Permit be modified as required herein; and

(d) EPA must approve those portions of the Wyoming Regional Haze SIP that are consistent with the terms of this Settlement Agreement. Provided, however, that unless EPA affirmatively disapproves such portions of the Wyoming Regional Haze SIP in a final rulemaking, the parties shall continue to abide by the terms of this Settlement Agreement.

7. **Changed Circumstances:** The Parties agree that this Settlement Agreement may be subject to modification if future changes in either: (i) federal or state requirements or (ii) technology would materially alter the emissions controls and rates that otherwise are required hereunder. In that case, either Party may request that the other Party enter into an amendment to this Settlement Agreement consistent with such changes. The Parties shall negotiate in good faith to amend the affected Settlement Agreement provision(s) consistent with the changed federal or state requirements or technology and with the purposes of this Settlement Agreement. If the Parties cannot agree on the proposed amendment, then either Party may request the EQC to determine if the proposed amendment is consistent with the changed federal or state requirements or technology and with the purposes of this Settlement Agreement. In that case, the Parties anticipate that the EQC determination will be incorporated into an EQC order that requires the Parties to proceed in accordance with its terms, including the possibility of entering into the proposed amendment. The Parties further anticipate that the EQC will retain continuing jurisdiction over the BART Permit Appeal and this Settlement Agreement for the foregoing purposes only.

8. **Reservation of Rights:** PacifiCorp reserves the right to appeal or challenge any actions by AQD, EQC or EPA that are inconsistent with this Settlement Agreement. In addition, if the EQC takes any action which is materially inconsistent with or in any way materially alters this Settlement Agreement, then this Settlement Agreement shall be voidable at the option of the Party materially affected by the EQC's actions.

9. This Settlement Agreement shall be admissible by either Party without objection by the other Party in any subsequent action between these Parties to enforce the terms hereof or as otherwise required herein.

10. Neither Party shall have any claim against the other for attorney fees or other costs incurred with the issues resolved. Each Party shall bear its own attorney fees and costs, if any, incurred in connection with the BART Permit Appeal and this Settlement Agreement. Each Party assumes the risk of any liability arising from its own conduct. Neither Party agrees to insure, defend or indemnify the other.

11. This Settlement Agreement is binding upon PacifiCorp, its successors and assigns, and upon the DEQ/AQD.

12. This Settlement Agreement may only be amended in writing, signed by both Parties.

13. Neither the DEQ/AQD nor the State of Wyoming nor any of its Agencies shall be held as a party to any contracts or agreements entered into by PacifiCorp to implement any condition of this Agreement.

14. Nothing in this Agreement relieves PacifiCorp of its duty to comply with all applicable requirements under the Wyoming Environmental Quality Act (WEQA), and rules, regulations, and standards adopted or permits issued thereunder. DEQ/AQD does not warrant or aver that PacifiCorp's completion of any aspect of this Agreement will result in compliance with the WEQA and rules, regulations and standards adopted or permits issued thereunder.

15. The State of Wyoming and the DEQ/AQD do not waive sovereign immunity by entering into this Settlement Agreement, and specifically retain all immunity and all defenses to them as sovereigns pursuant to Wyo. Stat. §1-39-104(a) and all other state law.

16. The Parties do not intend to create in any other individual or entity the status of third party beneficiary, and this Agreement shall not be construed so as to create such status. The rights, duties and obligations contained in this Agreement shall operate only among the Parties to this Agreement.

17. Should any portion of this Agreement be judicially determined to be illegal or unenforceable, the remainder of this Agreement shall continue in full force and effect, and either Party may renegotiate the terms affected by the severance.

18. The construction, interpretation and enforcement of this Agreement shall be governed by the laws of the State of Wyoming. The Courts of the State of Wyoming shall have jurisdiction over this Agreement and the parties, and the venue shall be the First Judicial District, Laramie County, Wyoming.

19. This Agreement may be executed in any number of separate counterparts any one of which need not contain the signatures of more than one Party but all of such

counterparts together will constitute one Agreement. The separate counterparts may contain original, photocopy, or facsimile transmissions of signatures.

20. The persons signing this Settlement Agreement certify that they are duly authorized to bind their respective Party to this Settlement Agreement.

21. This agreement is not binding between the Parties until fully executed by each Party.

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PACIFICORP ENERGY, a division of PacifiCorp

By: D. M. Rle

Name: DANA RALSTON

Title: VICE PRESIDENT GENERATION

Date: 11-2-2010

THE WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY

By: John V. Corra

Name: JOHN V. CORRA

Title: Director

Date: 11/3/10

THE WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY/DIVISION OF AIR QUALITY

By: Steven A. Dietrich

Name: STEVEN A. DIETRICH

Title: AQD - ADMINISTRATOR

Date: 11-3-10

Approved As To Form

Nancy E. Vehr
Nancy E. Vehr,
Senior Assistant Attorney General

Docket No. UE 374
Exhibit Sierra Club/403
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 403

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Selected Public Responses to Sierra Club Data Requests

UE 374/PacifiCorp
July 23, 2020
Sierra Club Data Request 8.3 – 1st Supplemental

Sierra Club Data Request 8.3

Refer to PAC/2500, Owen/16:8-19, with respect to gas conversion costs.

(a) Provide the Company's estimate of the costs of gas conversion at Naughton 3 as projected in September 2013.

(b) Provide a table of results of EPC contract bids for the gas conversion at Naughton 3 as known in January 2014.

(c) Provide Mr. Owen's work papers estimating the specific change on line 14, from costs "originally anticipated" to "significantly higher."

(d) Provide a definition and citation for the common use of the term "order of magnitude."

(e) Provide Mr. Owens' estimate of the present value of revenue requirements that would have "negatively impacted the competitiveness of the natural gas conversion."

1st Supplemental Response to Sierra Club Data Request 8.3

PacifiCorp provides the following supplemental response to Sierra Club Data Request 8.3:

(c) In the preparation of his testimony in docket UE 374, Mr. James Owen reviewed past testimony provided by the Company. This included testimony from Mr. Chad Teply that stated: "Based on information from the competitive market bids for the Naughton Unit 3 natural gas conversion EPC contract, the Company knew by January 2014 that implementation costs for that project were significantly higher—on an order of magnitude of 30 percent—than originally anticipated".

Mr. Owen conducted a thorough review of the basis for this statement. He reviewed the referenced competitive market bids and found that two competitive bids were received by the Company in December of 2013 in the amounts of $56,300,015 and $48,559,000. Based on discussions with project managers involved in receiving the bids at the time, he understood that the higher bid was not considered plausible, and thus additional consideration was prudent for the lower bid. He also learned that the lower bid (errantly) included a line item valued at $9,422,150 for repair/replacement of FGD bypass ducting, which would not be necessary for the gas conversion as proposed. He subtracted that amount from the bid, and re-calculated the project implementation cost to be $39,136,850.

UE 374/PacifiCorp
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Sierra Club Data Request 8.3 – 1st Supplemental

To ascertain the Company's anticipated costs for the project in late 2013, Mr. Owen reviewed Progress Review updates from early to mid-2013 and a Budget Calculation Sheet from early 2014. The costs in those documents ranged from $29,000,000 to $30,400,000, with the number $30,200,000 appearing twice. Mr. Owen therefore determined that $30,200,000 was a reasonable number to represent the company's estimate for the project in late 2013. A simple comparison calculation of the two values [($39,136,850-$30,200,000)/($30,200,000) =.2959 ≈30%] shows that the implementation costs for the project were significantly higher—on an order of magnitude of 30 percent—than originally anticipated. Thus, Mr. Owen adopted the statement into his testimony.

The parties contend that Pacific Power could have shut down, converted, or "mothballed" certain coal-fired units and continued operating others without adding costly controls.

3. Resolution

a. Prudence Standard for Utility Investments

Before we turn to the merits of this issue, we take this opportunity to clarify the prudence standard in ratemaking. Parties have raised questions about how the Commission applies the prudence standard, particularly with regard to the relevance of the decision-making process that a utility uses to make an investment.

The prudence standard is traditionally used to address the proper valuation of utility investment in rate base. Any investment found to be unreasonable is deemed imprudent and subject to partial or full disallowance. An example of a modern articulation of the prudence standard is as follows:

> A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company.[40]

Although the Oregon courts have not expressly discussed the applicability of the prudence standard in this state, this Commission has long used the standard when examining utility investments. Through various orders, the Commission has confirmed that prudence of an investment is measured from the point of time of the utility's actions and decisions without the advantage of hindsight,[41] that the standard does not require optimal results,[42] and the review uses an objective standard of reasonableness.[43]

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[40] Phillips, Charles, *Regulation of Public Utilities*, 341 (3d ed 1993).

[41] *See e.g.*, Order No. 99-033 at 36-37 (Jan 27, 1999) (prudence is determined by the reasonableness of the actions "based on information that was available (or could reasonably have been available) at the time."); Order No. 95-322 at 48 (Mar 29, 1995) (a prudence review takes into account the information that was available to decision makers at the time the decision was made. It does not engage in hindsight or second-guessing; to do so would be unfair.); and Order No. 99-697 at 52 (Nov 12, 1999) (we must determine whether NW Natural's actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances.)

[42] *See e.g.,* Order No. 98-353 at 9 (Aug 24, 1998) (this Commission has applied this prudency standard for many years in deciding whether to include in rate base the full amount of a utility's investment in a new resource (as opposed to a standard that, say, focuses on the outcome of the utility's decisions).); and Order No. 02-469 at 4 (Jul 18, 2002) (in applying this standard, the Commission does not focus on the outcome of the utility's decision.) .

[43] *See* e.g., Order No. 09-501 at 5 (Dec 18, 2009) (in a rate case the Commission would apply the "reasonable person" standard); Order No. 95-322 at 48 (Mar 29, 1995) (endorsing an expert witnesses use

In this proceeding, parties have questioned whether the Commission uses a prudence standard that focuses solely on the decision made by the utility, without regard to the decision-making process used to reach that decision. The questions arise from Order No. 02-469, which addressed Pacific Power's request to recover excess NPC. The Commission rejected claims that Pacific Power was entitled to no recovery because it was unable, due to the time that had elapsed, to provide contemporaneous evidence of key decisions relevant to the inquiry. The Commission agreed with the utility that:

> [I]f the record demonstrates that a challenged business decision was objectively reasonable, taking into account established historical facts and circumstances, the utility's decision must be upheld as prudent even if the record lacks detail on the utility's actual subjective decision making process.[44]

That language has raised questions whether our prudence standard focuses solely on the decision made by the utility, without regard to the decision-making process used to reach that decision. In particular, Staff reads the language to mean that, "while a utility's decision process is probative on whether the action itself is prudent, under the Commission's prudence standard, the primary focus is on the reasonableness of the action, not on the process leading up to it."[45]

Although imprecisely worded, the Commission's decision in Order No. 02-469 correctly concluded that a utility does not automatically fail its burden of proof if it is unable to present contemporaneous evidence of its own actions. Prudence is determined by what a utility "knew or should have known" at the time the decision was made. It is possible that the utility may be able to present sufficient information from external sources (what it should have known) to establish that its ultimate decision was prudent—regardless of what internal decision-making process was used (what it knew).

That order should not, however, be interpreted as saying that a utility's decision-making process is not relevant to a prudence determination. Contrary to any implication from the language in docket UM 995, the process used by the utility to make a decision to invest in a plant is highly valuable in determining whether the utility's actions were reasonable and prudent in light of the circumstances which then existed. The prudence standard examines all actions of the utility—including the process that the utility used to make a decision. Although there may be unique circumstances where a utility is able to overcome the inability to explain its internal decision-making processes, a utility's actions are generally a primary consideration in a prudence review.

This clarification as to the importance of a utility's decision-making process is consistent with recent Commission decisions. For example, we recently examined the prudence of certain hedging contracts entered into by Pacific Power. In that proceeding, we explained

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of a reasonable person standard, similar to that commonly employed in utility prudence review proceedings).

[44] *In the Matter of PacifiCorp, dba Pacific Power,* Docket Nos. UM 995, UE 121, UC 578, Order No. 02-469 at 5. (July 18, 2002).

[45] Staff/1500, Colville/2 (Aug 13, 2012).

that the decision-making process used by the utility was crucial in determining whether the hedges were prudent:

> To evaluate the prudence of a hedging contract, we will first examine the utility's hedging strategy. If the strategy is prudently designed (for example, it includes sound hedging goals, methodology, and targets, among other things), we will next examine whether the utility executed its strategy prudently.
>
> If a particular transaction is inconsistent with the strategy, or parties have raised issues that appropriately call the transaction into question, such as lack of market liquidity, we will then examine whether the utility provided adequate and contemporaneous analysis and documentation and a sound justification to support the transaction.[46]

Although that case involved the reasonableness of power costs and not the proper valuation of rate base, it supports the conclusion that the utility's decision-making process may be highly relevant as to whether a capital investment was prudently incurred. It is often central to the inquiry of whether the utility exercised the standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time the decision had to be made.

b. *Prudence of Pacific Power's Investments*

We now turn to the parties' arguments in this case. After reviewing the state and federal regulations applicable to Pacific Power, we conclude that a reasonable utility faced with emerging state and federal regulations would find that some action was required to comply with those rules. At the federal level, the EPA's RHR required states to prepare and submit implementation plans that demonstrated reasonable continuous progress in reducing regional haze in Class I areas. Even if states chose to implement an alternative program under Section 309, that alternative program had to demonstrate, at a minimum, even greater reasonable progress toward national visibility goals than they would otherwise achieve under Section 308. At the state level, both Wyoming and Utah prepared and submitted SIPs that demonstrated progress toward regional visibility goals, with progress reviews to be conducted in 2013 and 2018. Both SIPs contained provisions rewarding early emission reductions.

As the owner of major sources of emissions in both Utah and Wyoming, Pacific Power was required to take action to comply with the mandate that the region achieve reasonable progress toward the RHR's air quality goals. To help meet its obligation to serve its customers and efficiently operate its fleet of generating resources, Pacific Power acted prudently in initiating efforts to address the air quality and emissions regulations that affected its multiple units. Pacific Power states that since 1999 it has worked to reduce power plant emissions through its Comprehensive Air Initiative, and that for the plants at issue here it extensively analyzed its compliance alternatives, developed a long-

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[46] *In the Matter of PacifiCorp, dba Pacific Power*, Docket No. UE 227, Order No. 11-435 at 7. (Nov 4, 2011).

term pollution control strategy, and coordinated installation of controls with the utility's existing four-year outage cycle to reduce replacement power costs. We find Pacific Power's initial development of a coordinated and forward-looking response to be reasonable. We decline to find that a prudent utility faced with these state and federal regulations would have simply done nothing and waited to see what additional requirements emerged.

We further find, however, that Pacific Power failed to act prudently in two areas. First, we are not convinced by Pacific Power's claims that there were not legitimate alternative courses of action—both in terms of the mix of compliance actions and, particularly, in the timing of those actions—that could have allowed Pacific Power to meet its air quality requirements at a lower cost and risk to the utility's Oregon ratepayers. The record shows that throughout the period under question, even in response to changing circumstances, Pacific Power did not alter its course of action or consider alternatives of any kind. Second, we find that Pacific Power failed to perform appropriate analyses to determine the cost-effectiveness of the investments. Pacific Power's contemporaneous cost-effectiveness analyses were demonstrably deficient, and did not demonstrate the rigorous review that a prudent utility should have performed prior to making these significant investments.

We are not persuaded by Pacific Power's claim that the state and federal implementation of the RHR imposed a binding plant-specific emission limit on each of the utility's plants that had to be implemented at the time the investments were made. Although Pacific Power notes repeatedly that the milestones under the Backstop Trading Program were calculated using plant-specific emission limits, the program milestones established with those limits were, as Sierra Club notes, regional milestones. We similarly are not persuaded by Pacific Power's reliance on construction approval orders and permits that mandate specific SO_2 plant emission limits upon completion of construction. Pacific Power has been unable to present us with documentary evidence demonstrating that the Wyoming and Utah DEQs required Pacific Power to apply for all of the permits at issue here when it did so.

Pacific Power itself states that it began implementing its emission reduction commitments in 2005, "well ahead of the emission reduction timelines under the regional haze rules which require BART to be installed no later than five years following approval of the applicable Regional Haze SIP."[47] As cited by Sierra Club, documents from 2005 also show Pacific Power had a strategy of moving forward with air pollution controls that was independent of state or federal action.[48] Moreover, after it began implementing its air quality commitments, Pacific Power was confident enough that its emissions were sufficiently below regional milestones that it sought, in its 2007 IRP, acknowledgement to add two coal-fired resources that would begin operation in 2012 and 2014. In April of 2008, we did not acknowledge those plants.

The evidence also shows the WDEQ acknowledged the flexibility available under the Backstop Trading Program. In Wyoming's BART permit analysis for the Naughton plant, the WDEQ noted that, for SO_2, "the State of Wyoming submitted a [Section] 309

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[47] *See* Sierra Club/100, Fisher/21, *citing* Sierra Club/112, PacifiCorp's Emissions Reduction Plan.
[48] *See* Sierra Club Posthearing Brief at 3 (Nov 7, 2012), citing Confidential Sierra Club/115, Fisher/2 (Jun 20, 2012).

SIP as is allowed by the Regional Haze Rule. Part of the SIP submittal is a 'Better than BART' demonstration, required by rule, which does not require that each and every unit demonstrate emission controls that are 'Better than BART.' The demonstration is a regional demonstration."[49]

The yearly Regional SO_2 Emissions and Milestone Reports issued by the Western Regional Air Partnership also provided Pacific Power with notice that yearly emissions were far below the emissions limits established under the Backstop Trading Program. Early on, it was clear that the 2013 regional emissions would be much lower – regardless of Pacific Power's actions – and the limits would be readily met. Those reports showed that:

- The 2008 regional emissions were 20,000 tons lower than the 2013 limit.
- The 2009 emissions were more than 40,000 tons lower than the 2013 limit.
- The 2010 emissions were 54,000 tons less than the 2013 limit and more than 10,000 tons less than the 2018 limit.

We add that the regional milestone for 2013 was achieved before the retrofits at Naughton 1 and 2, Hunter 1 and 2, Bridger 3, and Wyodak were completed. Further, these levels do not include other expected actions that will further limit or reduce emissions in the region, such as the conversion of Naughton 3 to natural gas and the shutdown of the Carbon plants.

In addition to finding that Pacific Power failed to establish that it was required to make each of the disputed investments at the time that it did, we find that the utility conducted inadequate analyses to justify the plant upgrades. As pointed out by the parties, Pacific Power's cost-effective analyses were flawed in a number of ways:

<u>Assumption of Immediate Shutdown</u>: With the exception of the Hunter units, Pacific Power's PVRR(d) analysis compared the expected costs of installing emissions control equipment against immediately replacing the output of the plant with market purchases, even in instances when the utility anticipated a compliance date that would occur several years later. As shown by Sierra Club and CUB in their analyses, the use of a more realistic shut down date by itself significantly alters the economics of the projects.

<u>Lack of meaningful sensitivity and scenario analyses</u>: Major resource decisions should not rely largely on single point forecasts, but should instead be shown to be robust over a wide range of futures/scenarios and input assumptions. As CUB's and Sierra Club's analyses showed, the economics of the utility's projects changed significantly based on changes in the assumptions about single variables such as wholesale prices or closure date. This alone signals that all of the investments should have been stress-tested against a wide range of futures and varied input assumptions and that a second stage of more rigorous analyses were merited for a number of the investments. The *ad hoc* analyses

[49] *See* PAC/2002, Teply/262 (Sept 5, 2012).

that were conducted during this case cannot substitute for the depth and breadth of analyses that should have occurred at the time of the decision.

Failure to incorporate potential costs of known, emerging regulations: As Sierra Club points out, Pacific Power assigned no costs to some known, emerging regulations. In retrospect, the retrofit cost associated with some of those regulations at Pacific Power's units were substantial. Further, Sierra Club notes other legitimate modeling adjustments that Pacific Power failed to make at the time of its analyses .[50]

Failure to update analyses: While we do not expect a utility to engage in a never-ending process of reconsideration of its investment decisions, with major resource investments such as these, a reasonable utility would consider changing conditions that significantly impact the financial viability of the investments. The evidence in the record shows substantial changes in the economics of Pacific Power's investments if assumptions had been updated just prior to the time of at least two significant milestones: contract signing and the start of construction. With updated analyses, Pacific Power would have had more refined estimates of market prices, gas prices, capital costs, and costs of other regulations, among other factors. Sierra Club and CUB have shown substantial changes to the economics of the investments with properly updated analyses. For example, CUB and Sierra Club showed that if Pacific Power had conducted analyses for Naughton Units 1 and 2 before signing a contract in May 2009 to upgrade the units, and before beginning construction in June 2010, on each date the updated results would have shown a substantial negative PVRR(d) result for the proposed retrofits. As CUB and Sierra Club point out, updated analyses for these plants would have raised "red flags" which would have merited a slow-down in decision-making and further analyses.

The inherent limitations of a PVRR(d) analysis: Pacific Power acknowledges that its PVRR(d) analysis is limited by focusing solely on market purchases, rather than a mix of replacement resources. In fact, it justifies its investments in part by arguing that a gas-fired replacement resource would have resulted in more positive PVRR(d) results. Yet, there is nothing in the record that shows it conducted resource portfolio analyses at the time of its decisions that back up any of its assertions.

In addition, if Pacific Power had properly explored the potential flexibility in the timing of its options under the RHR, as we believe it had the opportunity to do, the utility and ratepayers would have benefited from additional information that could have been incorporated into cost-effectiveness analyses. That additional information, at a minimum, could have supported later potential shut down dates for use in the PVRR(d) analysis as suggested by CUB and Sierra Club. Indeed, had Pacific Power planned to delay investments at some of its plants, then the utility would have been clearly aware of the "phase-out" analysis conducted by PGE for its Boardman plant and prompted to evaluate the economics of a similar phase-out. As noted by CUB, that analysis permitted PGE to consider a phase-out of its Boardman plant geared toward shutting the plant in 2020, rather than investing in more costly upgrades necessary to allow the plant to operate past that date. Further, if Pacific Power had altered the timing of some of its investments, the utility and its ratepayers could also have benefited from analyses that

[50] *See* Sierra Club Prehearing Brief at 6-8.