Exh. DCG-1CT
Dockets UE-190529/UG-190530 and
UE-190274/UG-190275 (*consolidated*)
Witness: David C. Gomez
REDACTED VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-190529 and UG-190530 *(consolidated)***
In the Matter of the Petition of **PUGET SOUND ENERGY** **For an Order Authorizing Deferral Accounting and Ratemaking Treatment for Short-life UT/Technology Investment**	**DOCKETS UE-190274 and UG-190275 (*consolidated*)**

TESTIMONY OF

David C. Gomez

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

2018 Colstrip Outage, SmartBurn, Colstrip Unit 3 & 4 Coal Contract, Gas Transport Costs, Tacoma LNG & Wind Capacity Derates

November 22, 2019

CONFIDENTIAL PER PROTECTIVE ORDER – REDACTED VERSION

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David C. Gomez. My business address is 621 Woodland Square Loop S.E., Lacey, Washington 98503. My business mailing address is P.O. Box 47250, Olympia, Washington 98504-7250. My business email address is david.gomez@utc.wa.gov.

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

A. I am employed by the Washington Utilities and Transportation Commission (Commission) as the Assistant Power Supply Manager in the Energy Section of the Regulatory Services Division. I attained this position on July 1, 2012. Prior to my current position, I was the Deputy Assistant Director in the Solid Waste and Water Section of the Regulatory Services Division.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since May 2007.

Q. Please state your educational and professional background.

A. I hold a Bachelor of Arts degree in Business from Hamline University and a Masters of Business Administration degree from the University of Saint Thomas; both universities are located in Saint Paul, Minnesota.

Before joining the Commission, my relevant professional experience consisted of 31 years in a variety of fields, including management, contracting, supply chain, procurement, operations and engineering. I hold professional certifications from the Institute for Supply Management (ISM); APICS – The Association for Operations Management; Universal Public Procurement Council (UPPC); and QAI Global Institute (Software Testing).

Q. What are your duties with the Commission?

A. I perform accounting and financial analysis of regulated utility companies, as well as legislative and policy analysis. I presented testimony on behalf of Commission Staff in Docket UE-121373, regarding the Coal Transition Power Purchase Agreement between Puget Sound Energy and TransAlta Centralia Generation LLC; Dockets UE-130043 and UE-140762, Pacific Power's 2013 and 2014 general rate cases; Puget Sound Energy's 2013, 2014 and 2016 Power Cost Only Rate Cases (PCORCs) and 2017 and 2018 General Rate Cases (GRC). I also have provided testimony in Avista's last five general rate cases: Dockets UE-140188, UE-150204, UE-160228, UE-170485 and UE-190334. Additionally, I have provided Staff recommendations to the Commission at numerous open meetings, and worked on various Commission rulemakings.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the scope of your testimony in this proceeding?

A. I respond to a number of issues contained in the prefiled direct testimony of Puget Sound Energy (PSE or Company) witnesses: Mr. Paul Wetherbee, Mr. Ron Roberts, and Mr. Duane Henderson. I propose adjustments to PSE's level of test year capital additions and expense as well as pro forma power costs. My colleague, Ms. Jing Liu, will also address pro forma power costs, however, I am Staff's principal witness in the area of pro forma power costs.

Q. What issues are you addressing in your testimony?

A. I address Colstrip Units 3 and 4 test year capital costs and expenses resulting from the 2018 forced outage and the Company's investment in SmartBurn. I also comment on the pending coal fuel contract for Colstrip Units 3 and 4 given the expiration of the current contract with Westmoreland Mining LLC (Westmoreland) at the end of this year. For pro forma power costs, I provide testimony on the Company's proposal to derate the capacity factor of its wind resources as well as my proposed adjustments to pipeline transport costs for PSE's gas plants. Finally, I comment on the Company's inclusion of capital costs in the test year for gas distribution system projects associated with the Tacoma LNG project.

Q. What are your electric adjustments?

A. My recommended electric adjustments are summarized in the table below. For the test year, I remove Operations and Maintenance (O&M) expense and capital directly attributable to the 2018 Colstrip outage. I also recommend disallowance of PSE's share of SmartBurn for Colstrip Units 3 and 4.

For pro forma power costs, I propose restoring PSE's wind resource capacity factors in the AURORA model which have been in place since the 2011 GRC.[1] In this case, PSE is seeking to derate its owned and contracted wind resources within the AURORA model's rate year simulation based on the results of a 2016 forecast. Finally, I increase pro forma revenue from PSE's gas optimization sales by $[redacted], while at the same time increase pro forma fixed pipeline costs by this same amount, resulting in a net impact to rate year power costs of zero dollars.

Staff Witness Gomez Electric Adjustments (000's)	**NOI**	**Ratebase**	**Revenue Impact**
2018 Colstrip Outage Ratebase	-	$(326)	$(32)
2018 Colstrip Outage Expense	$415		$(552)
SmartBurn	$(432)	$(5,272)	$(1,089)
Restore Wind Capacity Factors	Included in Staff Variable Power Cost Adjustment; Ref. Staff Revised SEF-7.01		
Gas Transport	-	-	-

Q. What are your proposed gas adjustments?

A. The Company included in its test year $31.5 million in gas distribution system capital additions which connect the Tacoma LNG project to PSE's gas distribution system. I recommend removal of these capital costs from the Company's test year rate base. While the Company identifies a small benefit associated with these two distribution system projects, for all intents and purposes these projects are part of the Tacoma LNG project and therefore their costs and prudency should be evaluated

[1] Wetherbee, Exh. PKW-1CT at 71:11-19.

together with the rest of the plant once it is in service. PSE is projecting Tacoma LNG project's commercial operating date to be in late 2020.[2]

Staff Witness Gomez Gas Adjustment (000's)	NOI	Ratebase	Revenue Impact
Remove Tacoma LNG project rate base	$(831)	$(26,191)	$(3,378)

III. COLSTRIP UNITS 3 & 4

Q. This portion of testimony addresses numerous issues related to Colstrip Units 3 & 4. What specific topics regarding Colstrip Units 3 & 4 are you addressing?

A. I start my examination of Colstrip Units 3 & 4 with a discussion of the 2018 outage, its impact and recommendation on costs associated with the outage; I then turn to an analysis of the Company's investment in SmartBurn and finish my examination of Colstrip Units 3 & 4 with a discussion concerning a possible new coal fuel contract.

A. 2018 Outage: Background and Impact.

Q. Please describe the Colstrip generation outage and derate that occurred in 2018.

A. During the second quarter of 2018, Units 1 and 2 were offline. During the same quarter and the next quarter, Units 3 and 4 were forced offline by the operator, Talen. This forced outage was due to violating emissions standards. Unit 3 was removed from service on June 28 and kept offline until July 8. Unit 4 was removed from service on June 29 and kept offline until July 17. When these units came back online during the period of non-compliance with emissions standards, they were derated to

[2] Gomez, Exh. DCG-2 at 2.

run only for the purposes of gathering information, performing diagnostics, evaluating potential remedial actions, and testing.

Q. Please describe the emissions standards that forced these units to be shutdown.

A. The Mercury Air Toxics Standard[3] (MATS) requires that particulate matter (PM) emissions be used as a surrogate for toxic emissions or non-mercury metals. MATS also requires that the Colstrip Units maintain a rolling 30-day average PM emission rate of 0.030 pounds per million British Thermal Units (1b/MMBtu). This means the average PM emission rate across all four Colstrip Units must be less than or equal to 0.030 lb/MMBtu. Starting in the first quarter of 2018, the PM levels at Colstrip were elevated, and were at or just below the PM limit of 0.030 lb/MMBtu.[4]

During the second quarter of 2018, Units 1 and 2 were offline and therefore not subject to MATS PM emission testing. On June 21, 2018, Unit 3 was tested and the results indicated a PM emission rate of 0.043 lb/MMBtu. On June 26, 2018, Unit 4 was tested and the results indicated a PM emission rate of 0.051 lb/MMBtu. These tests revealed that Colstrip Units 3 and 4 were out of compliance with the PM emission limit. Talen notified the Montana Department of Environmental Quality (MDEQ) of the non-compliant test results on June 28, 2018. Due to this violation of the PM emission limit, Units 3 and 4 went into a forced outage.

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[3] The Colstrip Units are subject to 40 C.F.R. Part 6, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—commonly referred to as the Mercury Air Toxics Standard.
[4] Gomez, Exh. DCG-3.

Q. When were the units brought back on line?

A. On September 4, 2018, Unit 4 demonstrated compliance with a PM emission rate of 0.021 lb/MMBtu. On September 11, 2018, Unit 3 demonstrated compliance with a PM emission rate of 0.024 lb/MMBtu.

Q. Did PSE procure power from different sources during these outages?

A. Yes. According to the Company, the 2018 Colstrip outage coincided with particularly high market energy prices resulting in an estimated $17.9 million increase to power cost in the deferral year.[5] All three Colstrip owners are now seeking recovery of their replacement power costs in their respective power cost adjustment mechanisms.

B. Staff's Recommendation concerning Colstrip Outage costs.

Q. Is Staff evaluating the prudency of the outage and derate of Units 3 and 4 in this GRC?

A. No. Staff conducted informal discovery into the prudency of the 2018 Colstrip outage in PSE's 2019 Power Cost Adjustment (PCA) annual review filing in Docket UE-190324. PSE filed its 2019 PCA annual review pursuant to the settlement stipulation in Docket UE-130617, which requires PSE to file an annual report during the month of April to allow the Commission and interested parties to "review the

[5] Wetherbee, UE-190324, Exh. PKW-1CT (revised Nov. 13, 2019) at 15:3-9.

prudence of the power costs included in the deferred calculations; costs determined to be imprudent can be disallowed at that time."[6]

While it is PSE's burden to prove that the replacement power costs associated with the 2018 Colstrip Outage were prudently incurred, the Company's initial filing in UE-190324 failed to provide the information necessary for Staff to make such a recommendation to the Commission. Despite extensive efforts in informal discovery, Staff was unable to obtain the necessary information from PSE to support a recommendation to the Commission to approve the 2018 deferral balance. The same was true for the two other Colstrip owners' Power Cost mechanism filings.

As a result, Staff filed its motion on September 26, 2019, asking the Commission to consolidate all three annual power cost mechanism filings into a single adjudicative proceeding for the purpose of determining the prudency of the 2018 Colstrip outage.[7] On October 24, 2019, the Commission issued its order denying Staff's motion to consolidate, deciding instead to suspend both PSE's PCA and Pacific Power's PCAM, set both for adjudication, and require Staff to initiate an investigation into the 2018 Colstrip outage. The stated purpose of Staff's investigation is to assess <u>the prudency of the decisions made and actions taken by the Colstrip owners *prior* to the outage</u> as well as the level of additional costs incurred by the companies to acquire replacement power as a result of the outage.

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[6] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-130617, Order 11, Attachment A at 2 (Aug. 7, 2015); *see also Wash. Utils. And Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-130617, Order 11 (Aug. 7, 2015).

[7] *In re Petition of Puget Sound Energy for Approval of its April 2019 Power Cost Adjustment Mechanism Report*, Docket UE-190324, Comm'n Staff Mot. for Severance and Consol. of Proceedings Pursuant to WAC 480-07-320 (Sept. 26, 2019).

Q. Does Staff address test year capital additions for Colstrip?

A. Yes. According to Mr. Roberts, PSE has included approximately $44 million in test year capital additions related to Colstrip.[8] As I mentioned previously, Staff is contesting $7.5 million of that amount which is comprised of PSE's share of capital costs associated with the 2018 Colstrip outage and the installation of SmartBurn for Units 3 and 4. It is my understanding that the prudency of capital costs associated with 2018 Colstrip Outage will be determined in the Outage investigation docket (UE-190882).

C. SmartBurn

Q. What is your recommendation related to Smart Burn?

A. I recommend that the Commission disallow costs associated with SmartBurn. PSE has failed to meet its evidentiary burden to show that its share of SmartBurn capital costs were prudently incurred. In my review of PSE's SmartBurn investment, I employ the Commission's prudence standard and the guidance provided by the Commission in its final order in Avista's 2017 GRC. In its final order, the Commission concluded that Avista had:

> …provided insufficient information related to its investments at Colstrip Units 3 and 4. The Company presents an argument for the Smart Burn investment on rebuttal, but it does not dispel Staff's primary concern: that the investment does not appear to have been required by any state or federal laws. Any future compliance obligations that the Smart Burn investment might have helped mitigate are purely speculative, and it is unclear whether

[8] Roberts, Exh. RJR-1T at 9:3-6.

> the decision by the Colstrip owners to proactively take on future assumed compliance obligations reflected that retirements of other coal units in the region might reduce any compliance obligations for Colstrip Units 3 and 4.[9]

In addition to the Commission's final order in the Avista GRC, I also examined the direct testimony of Sierra Club witness Dr. Ezra D. Hausman in Case No. AVU-E-1701 before the Idaho Public Utilities Commission.[10]

Staff's reliance on the guidance contained in the Avista GRC order and Sierra Club's testimony in the Idaho case is appropriate here given that the issues and facts surrounding the prudency of the decision to install SmartBurn are the same for each of the Colstrip owners.

Q. What is your understanding of the prudence standard?

A. The Commission has articulated its prudence standard in a number of decisions. In one such decision, the Commission stated:

> It is generally conceded that one cannot use the advantage of hindsight. The test this Commission applies to measure prudence is what a reasonable board of directors and company management [would] have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures.[11]

The Commission has also explained that, after a company initiates a project, that company must continue to evaluate and ensure its prudence:

> Simply because the decision to begin a project is prudent does not mean the continuation or completion of the project is *ipso facto* prudent. The Commission believes that a company must continually evaluate a project as it

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[9] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-170485 & UG-170486, Order 07, p. 68, ¶ 204 (Apr. 26, 2018).
[10] Gomez, Exh. DCG-4.
[11] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14, p. 34, ¶ 65 (May 13, 2004) (citations omitted).

> progresses to determine if the project continues to be prudent from both the need for the project and its impact on the company's ratepayers.[12]

In addition, the Commission has made it clear that the company bears the burden of demonstrating prudence.[13]

Q. Did you see any evidence to suggest SmartBurn was a factor in the 2018 Colstrip Outage of Units 3 and 4?

A. No. Staff did not find anything specific to implicate SmartBurn in the Root Cause Analysis report (RCA) commissioned by Talen and the other Colstrip owners.[14] However, among the RCA's recommended solutions to address PM control issues at Colstrip is the following statement:

> <u>Change the objectives of furnace optimization</u>: The burners are currently tuned to minimize slagging and <u>NOX emissions</u>, while also maintaining output. Recommend including control of PM as an objective of boiler operation. Status: In process.[15]

Mr. Roberts' testimony does not address the impact to NOx emissions resulting from the retuning of the Colstrip burners. As a result, Staff cannot validate if PSE's claimed improvements to NOx emissions resulting from the installation of SmartBurn on Units 3 and 4 will be completely erased or even increase as a result of the actions taken to bring PM emissions back into compliance.

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[12] *Wash. Utils. & Transp. Comm'n v. The Wash. Water Power Co.*, Cause No. U-83-26, Fifth Supplemental Order, p. 13 (Jan. 19, 1984).

[13] *Id.* ("As with all issues, the company bears the burden to prove initiation, construction and continuation of the project was prudent."); *see also Petition of Puget Sound Power & Light Co. for an Order Regarding the Accounting Treatment of Residential Exchange Benefits,* Docket No. UE-920433, Eleventh Supplemental Order, p.19 (Sept 21, 1993) ("Puget must make an affirmative showing of the reasonableness and prudence of the expenses under review . . . even in the absence of a challenge by another party.").

[14] Gomez, Exh. DCG-5.

[15] *Id*. at 21 (emphasis added).

It is important to note that Staff is not basing its recommendation to disallow the capital costs associated with the installation of SmartBurn on Units 3 and 4 on whether or not it contributed in any way with the outage and derate. Instead, Staff's recommendation is that SmartBurn continues to be unnecessary and provides no benefit to PSE's ratepayers.

i. PSE Failed to Demonstrate the Need for SmartBurn.

Q. Has PSE met its burden to demonstrate the need for SmartBurn?

A. No. Mr. Roberts states that PSE and the other Colstrip owners had anticipated future additional NOx reduction requirements which they believed would require the installation of Selective Catalytic Reduction (SCR) technology for each Colstrip Unit. He says that this expectation arose from both the Federal Implementation Plan (FIP) to address regional haze in the State of Montana[16] and the State of Montana's Regional Haze Progress Report dated August 2017.[17]

Q. Are there any requirements for the installation of SCR at Colstrip Units 3 and 4?

A. No. Section III - Final Action, of the FIP contains a table identifying the control technologies, associated costs, and emission reductions for a handful of facilities including Colstrip Units 1 and 2. Units 3 and 4 were also analyzed, but under a different source category than Units 1 and 2. However, the FIP applied no additional emission control requirements or limits on Units 3 and 4 at that time.

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[16] Gomez, Exh. DCG-6.
[17] Gomez, Exh. DCG-7.

Q. What happened to the emission limits for Units 1 and 2 imposed by the FIP?

A. On June 9, 2015, the United States Court of Appeals for the Ninth Circuit vacated the emission limits for Colstrip Units 1 and 2.[18] By then, SmartBurn had already been installed on Unit 2.[19] In 2016, an agreement was reached between Sierra Club and the owners of the Colstrip facility to shut down Colstrip Units 1 and 2 by 2022, and the owners agreed to comply with certain emission limits for NOx and SO_2.

Q. Does the State of Montana's Regional Haze Progress Report of 2017 recommend the installation of SCR?

A. No. The Regional Haze Progress Report of 2017 (2017 Report) evaluates visibility progress in Montana from the baseline years of 2000-2004 and, more specifically, progress since the 2012 publication of the Montana FIP. The report provides a five-year update on the current status of visibility at the Class I Areas affected by emissions from Montana sources of air pollution and describes statewide emissions reductions. The report concluded that the Montana FIP was adequate and did not require substantive revision to achieve established visibility goals.[20]

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[18] *National Parks Conservation Ass'n v. E.P.A.*, 788 F.3d 1134, 1143 (9th Cir. 2015).
[19] Gomez, Exh. DCG-7 at 21.
[20] Gomez, Exh. DCG-7 at 10-11.

Q. Chapter 2 of the 2017 Report mentions the installation of SmartBurn on Units 3 and 4. Was the installation of SmartBurn mandated by either the FIP or the 2017 Report?

A. No. The 2017 Report's mention of the installation of SmartBurn on Units 3 and 4 describes a voluntary action on the part of the Colstrip owners.[21]

ii. PSE Failed to Maintain Appropriate Documentation

Q. Did Mr. Roberts provide any contemporaneous documents which memorialized the decisions made by the Company and the other Colstrip owners to install SmartBurn on Units 3 and 4?

A. No. Mr. Roberts' testimony and exhibits provide no such contemporaneous documents. He produces no evidence showing what "future regulatory obligation[s]"[22] were contemplated by PSE's management at that time, including analysis showing the "wide variety of NOx control solutions"[23] that were considered by the owners of Units 3 and 4 when the decision was made to install SmartBurn. It would seem that providing the required evidence would be rather easy as documentation regarding operating and capital budgets should be maintained as per Section 17(c) of the Colstrip Unit 3 and 4 Ownership and Operation Agreement. Section 17 requires the preparation and distribution, to all owners, of written minutes of the Project Committee, whose responsibilities include the approval of the annual

[21] Gomez, Exh. DCG-7 at 24.
[22] Roberts, Exh. RJR-1T at 14:11-13.
[23] *Id*. at 17:7-11.

Colstrip Unit 3 and 4 operating and capital budgets.[24] While it appears that capital decisions should be documented and then provided to Staff in the conduct of a prudence review, no evidence supporting the decision has been provided.

iii. PSE Failed to Demonstrate the Benefit of Installing SmartBurn.

Q. What evidence did Mr. Roberts provide to substantiate claims about the benefits of installing SmartBurn in Units 3 and 4?

A. None, other than a reference to an eight percent improvement in NOx removal.[25]

Q. Did you investigate the source of Mr. Roberts' claim of eight percent improvement in NOx removal?

A. Yes. Staff infers that Mr. Roberts' source for this claim is on page 2-8 of Exh. DCG-7. However, the 2017 Report states that the eight percent was an expected, not actual, improvement in NOx removal. Additionally, Footnote 22 identifies the source of this information as a conversation with Mr. Gordon Criswell of Talen Energy.

Q. How about Mr. Roberts' claims of lower O&M and capital costs as a result of installing SmartBurn?

A. Mr. Roberts provides no evidence for such claims.

[24] Gomez, Exh. DCG-8.
[25] Roberts, Exh. RJR-1T at 17:1-6.

iv. The Decision to Install SmartBurn was Imprudent.

Q. You examined actual NOx emission data reported to EPA for Colstrip Units 3 and 4 before and after the installation of SmartBurn. What did you conclude as a result?

A. Both Units 3 and 4 improved very little, if at all. The observed decrease in NOx levels after the installation of SmartBurn for both units was 0.01 lbs/MMBtu.[26]

Q. How does actual emission data from Colstrip Units 3 and 4, operating with SmartBurn, impact the prudency of the decision to invest in SmartBurn?

A. The current operating status of the SmartBurn investment is not relevant to the decision by the Company to invest in SmartBurn. However, it demonstrates that SmartBurn does not, and has not, provided any benefit through reduced emissions. Therefore, based on my testimony above, the decision to invest in SmartBurn was imprudent.

v. The SmartBurn Investment Should Be Disallowed.

Q. In summary, has PSE met its burden that the installation of SmartBurn on Units 3 and 4 was prudent?

A. No. The Company has not provided evidence supporting its investment in SmartBurn. There is no evidence that SmartBurn is required to comply with Federal law regarding NOx levels. There was no documentation provided that supported the investment. Further, the investment is not currently providing any benefit to

[26] Gomez, Exh. DCG-9.

ratepayers, as NOx levels were decreased by only 0.01 lbs/MMBtu. Therefore, absent evidence of need, the Company's decision making process, or a substantial improvement in NOx levels, I recommend that the Commission reject $7.2 million of PSE's test year capital addition for SmartBurn.

D. Colstrip Unit 3 and 4 Coal Fuel Contract

Q. What is the status of the new coal contract?

A. In his confidential second exhibit to his prefiled direct testimony, Mr. Ron Roberts provides an update on the status of the Colstrip Units 3 and 4 Coal Purchase and Sale Agreement which is due to expire at the end of this calendar year. According to Mr. Roberts, [redacted][27] Mr. Roberts provides no estimate as to the dollar impact to pro forma power costs of the new coal contract.

Q. With no coal contract in place starting January 1, 2020, what coal fuel costs has PSE included in this case?

A. The Company includes $[redacted] million of variable coal fuel expense in its pro forma power costs. This amount is $[redacted] million less than the level of coal fuel expense in

[27] Roberts, Exh. RJR-3C at 19:2-18.

PSE's 2017 GRC. This lower level of expense is due to a decrease in annual tonnage used to fuel Units 3 and 4 in the rate year. PSE also includes $[redacted] million in fixed fuel charges for the rate year which is little over $500K less than the level of fixed fuel charges in the 2017 GRC. The Colstrip coal fuel fixed and variable costs in this GRC are based on Talen's 2019 Annual Operating Plan (AOP) of August 2018.

Q. Is the Company's level of pro forma coal fuel expense in this case representative of costs they will incur in the rate year?

A. No. According to Mr. Roberts, the new owners of the Rosebud Mine, Westmoreland Mining LLC (Westmoreland), [redacted].[28] This assumes, of course, that Talen and the other Colstrip owners select Westmoreland and the Rosebud mine to fuel Units 3 and 4 beyond 2020.

Q. Is there a very real possibility that the new Colstrip Unit 3 and 4 Coal Purchase and Sale Agreement will be with a mine(s) other than Westmoreland Mining LLC's Rosebud Mine?

A. Yes. On February 15, 2019, the Montana Legislature's Senate Natural Resources Committee heard testimony regarding Senate Bill 252, proposing amendments to Sections 75-20-213 and 75-20-219 of the state's Major Facility Siting Act (SB 252).

[28] Roberts, Exh. RJR-3C at 21:4-9.

SB 252 proposed to greatly simplify the process by which Colstrip could switch its coal fuel source to another mine(s) and/or to another Area(s) of Rosebud Mine.[29]

Testifying in support of SB 252, was a representative for Talen Energy, Mr. Mark Taylor. In his testimony before the Senate Committee, Mr. Taylor provided legislators with an exhibit titled FACT SHEET: SB 252.[30] Mr. Taylor's fact sheet outlines Talen's plans towards ensuring the continued operation of Colstrip Units 3 and 4 for many years to come.

Q. Was SB 252 signed into law?

A. No. On May 3, 2019, Montana Governor Steve Bullock vetoed SB 252 stating:

> Decades ago, the people of Montana determined that it was important to review major proposed changes to power plants in our state. This policy, embodied in a law called the Major Facility Siting Act (MFSA), is designed to 'ensure protection of the state's environmental resources . . . consideration of socioeconomic impact' and 'provide citizens with the opportunity to participate' in these decisions. This policy has worked for Montana, balancing the responsible development of energy facilities with the constitutional obligation to maintain and improve a clean and healthful environment for future generations. Senate Bill 252 would create a major exception to the MFSA law and apply it only to the largest power plants. In particular, SB 252 would limit the ability of the Department of Environmental Quality (Department) to analyze and mitigate environmental impacts that result from changes to a power plant's fuel sources.[31]

Q. Has the veto of SB 252 foreclosed Talen's ability to source coal from another mine?

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[29] Gomez, Exh. DCG-10. Section 7.1 of the Amended Restated Coal Supply Agreement (ARCSA) specifies that unless otherwise mutually agreed to in writing by all parties, no Approved Annual Operating Plan may use coal other than coal from Area C of the Rosebud Mine.
[30] Gomez, Exh. DCG-11.
[31] Gomez, Exh. DCG-12 (emphasis added).

A. Apparently not. On May 10, 2019, MDEQ amended Talen's Montana Site Certificate issued under MFSA to allow Units 3 and 4 to: (1) Utilize non-Rosebud Seam coals from mines identified in the January 22, 2019, application to modify Montana Air Quality Permit 0513-10[32] and the March 15, 2019, application to amend the Certificate; and (2) Utilize rail and/or truck delivery facilities for the non-Rosebud mine coal as authorized by Montana Air Quality Permit 0513-11, March 13, 2019.

In Mr. Roberts' prefiled confidential second exhibit, he describes the Company's concern over the construction of a coal unloading terminal at Colstrip. He states: [redacted]"[33]

Q. According to MDEQ, what are some of the expected environmental impacts associated with the Talen's plans to construct a new rail and/or truck coal delivery facility for Colstrip?

A. In its issuance of Montana Air Quality Permit #0513-11 dated March 13, 2019, MDEQ discusses Talen's estimate of the maximum potential increase in Particulate

[32] Gomez, Exh. DCG-13, Page 1. The mines identified are as follows: Spring Creek Mine, the Decker Mine, the Signal Peak Mine, and the Otter Creek Mine in Montana and the Eagle Butte Mine, the Belle Ayre Mine, the Rawhide Mine, the North Antelope Rochelle Mine, the North Antelope Rochelle (north) Mine, the Caballo Mine, the Coal Creek Mine, the Black Thunder Mine, the Antelope Mine, and the Cabrero Rojo Mine in Wyoming.
[33] Roberts, Exh. RJR-3C at 20:17-21:3.

Matter emissions associated with a rail and/or truck delivery facility planned for the Colstrip site.[34] Under six different alternate operating scenarios, the maximum increase came from the scenario where trucks would haul seven million tons of coal per year to the Colstrip site.[35] These trucks would haul coal from presumably one or all of the mines referred to in Talen's January 22, 2019 application to modify Montana Air Quality Permit 0513-10.[36] Under this truck hauling scenario, Staff estimates Particulate Matter emissions from the plant will incrementally increase by 2.3 percent (485 tons per year).

Q. Was there public comment on Talen's air permit application for its planned rail and/or truck delivery facility?

A. Yes, two comments were received by MDEQ; one from Talen and the other from Western Energy, the subsidiary of Westmoreland that operates the Rosebud Mine. For Staff, Western Energy's comments are on-point with regard to the risk being assumed by Talen in its scheme to diversify Colstrip's coal supplier base (emphasis added by Staff):

> Western Energy Company ("Western"), a subsidiary of Westmoreland Coal Company, is the exclusive source of fuel to all four of the units at the Colstrip Generating Station ("Colstrip") (operated by Talen Montana, LLC, hereafter "Talen") for over 40 years, and since the inception of the station. As such, we believe that Permit Number 0513-11 (the Permit) as proposed does not properly address the economic and environmental impacts to the Colstrip community and the State of Montana of the proposed coal unloading facility and the use of an alternative fuel source. The Permit Application does not adequately address air quality considerations and impacts in relation to an unknown fuel type should Talen choose to switch fuels. <u>As recently as summer of 2018 there were</u>

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[34] Gomez, Exh. DCG-14.
[35] Seven million tons represents the annual coal fuel consumption amount for Colstrip Units 3 and 4 combined.
[36] Gomez, Exh. DCG-14, Section IV.

> prolonged outages at Colstrip associated with emission control mechanisms with coal that is familiar to Talen and the other co-owners and has been supplied for the past 40 years. An introduction of a new and untested fuel source has the potential to have significant environmental impacts including but not limited to emission safeguards, additional disturbance to land as it relates to a new loading facility and any related infrastructure needs, and interruptions in power generation and supply. Any such environmental impacts should be thoughtfully considered through the appropriate NEPA [National Environmental Policy Act] analysis as has been required of Western for a comprehensive evaluation of environmental impacts.[37]

Q. In light of Talen's plans for Colstrip, does Westmoreland have plans of its own for the Rosebud Mine?

Yes. Western Energy submitted a mine permit application package on November 2, 2011, to MDEQ for a new permit area known as Area F. As part of the permitting process for Area F, the environmental impacts of the proposed expansion of the mine were assessed jointly by MDEQ and the United States Department of the Interior, Office of Surface Mining Reclamation and Enforcement (OSMRE).[38]

Q. What environmental impacts are associated with the expansion of the Rosebud Mine?

A. The addition of Area F would add 6,746 acres, and approximately 70.8 million tons of recoverable coal reserves to the Rosebud Mine, extending the operational life of the mine by 8 years at the current rate of production. Operations in Area F would last 19 years and would disturb 4,260 acres. Of this land, 2,159 acres would be disturbed by mining; the remainder would be disturbed by highwall reduction, soil storage,

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[37] Gomez, Exh. DCG-14 at 28-29 (emphasis added).
[38] Gomez, Exh. DCG-15 at 5.

scoria pits, haul road construction, and other mine-related activities. Current surface land uses in Area F include grazing land, pastureland, cropland, and wildlife habitat.[39]

Q. Does PSE express other concerns about the future viability of Units 3 and 4 given their age?

A. Yes. Besides the likely considerable, yet unknown cost impacts of a new coal contract, the "[redacted] The Company estimates the cost to replace this critical component of the [redacted] boiler at $[redacted] million. Mr. Roberts goes on to say, [redacted]."[40] Staff couldn't agree more.

Q. Staff witness Ms. Jing Liu recommends excluding the proforma cost of Unit 4's major maintenance scheduled for June of 2020. Do your concerns over the future viability of Unit 4 lend support to her recommendation?

Yes. In her testimony, Ms. Liu expresses no confidence in the accuracy of Talen's major maintenance cost estimates for the rate year given the large variance between pro forma major maintenance amounts allowed in the 2017 GRC and actuals.

[39] Gomez, Exh. DCG-15 at 5.
[40] Roberts, RJR-3C at 10:14-22.

Considering Unit 4's failing [redacted] of the boiler, the yet to be completed Colstrip 2020 budget and the uncertain economics of continued operation of the unit, I concur with Ms. Liu's recommendation to remove $[redacted] in pro forma major maintenance expense for Unit 4 in the rate year.

Q. Have these Colstrip related issues surfaced in the Company's 2019 IRP Technical Advisory Group (TAG) meetings?

A. No, not specifically. The Company had committed to answer the questions posed by the Commission in the 2017 Acknowledgment Letter when it submitted its 2019 IRP draft which was expected to be filed by November 15, 2019.[41] The Commission's questions are as follows:

1. Regarding fuel source cost and risk:
   a. What is the cost and physical supply risk of coal from the Rosebud mine due to Westmoreland bankruptcy?
   b. As the need for fuel for Colstrip declines, how does the increased cost per unit of coal affect the economic dispatch of Colstrip? This should be modeled in PSE's IRP portfolio dispatch model.
   c. How does fuel supply risk for Colstrip compare to that of natural gas?
   d. How are the economics of Colstrip Units 3 & 4 affected if natural gas prices continue to remain relatively flat?

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[41] Gomez, Exh. DCG-16.

2. Has PSE quantified capacity replacement costs for Colstrip 3 & 4 that it could use as a basis of seeking replacement capacity as an alternative to any large capital investments it faces at Colstrip? This question should be answered in the context of the provisions of E2SSB 5116.[42]

While Staff and Sierra Club have brought forth questions to PSE pertaining to the continued operation of Colstrip Units 3 and 4, no specifics have emerged from the TAG on this very important issue.

Q. What is the Company's plan to incorporate the costs of the new Colstrip Unit 3 and 4 coal contract in this GRC?

A. PSE's initial filing is silent as to how and when the Company plans to incorporate costs of the new Colstrip coal contract into its power cost baseline in this case.

Q. Did the Company indicate it would file supplementary testimony to update its power costs to include the effects of a new Colstrip coal contract?

A. No. In its supplemental response to Staff DR No. 75, PSE states that the new Colstrip coal contract is still being negotiated and that the Company has no plans to supplement its initial testimony on this issue before the deadline for Staff and other parties' responsive testimony.[43] Staff's deadline for responsive testimony in this

[42] *Id*.
[43] Gomez, Exh. DCG-17 at 6.

case is 26 working days before the expiration of the Colstrip Unit 3 and 4 coal contract.

Q. Did the Company indicate it would update its power costs with new Colstrip coal contract costs when it files its rebuttal testimony?

A. No. The Company says it has no plans to include the effects of a new coal contract in its rebuttal update to power costs, even if the contract had been signed and costs known prior to the rebuttal testimony deadline of January 15, 2020. PSE says it is limited to a list of agreed upon rebuttal updates to power costs contained in Appendix B to Order 03 in this case, which does not include the cost impact of a new Colstrip coal contract. Instead, PSE says it might inform the Commission of the final execution of the coal contract and its costs in its rebuttal testimony.[44]

Q. Did the Company indicate that it would update its power costs with new Colstrip fuel costs in its compliance update to power costs at the end of the case?

A. No. In response to Staff DR No. 57, Mr. Paul Wetherbee correctly describes the Commission policy that power costs be set as closely as possible to costs that are reasonably expected to be incurred following the conclusion of a GRC.[45] This is accomplished via a compliance filing by the Company following the Commission's issuance of a final order in the proceeding. He identifies the new Colstrip coal

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[44] Gomez, Exh. DCG-17 at 6.

[45] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UG-040640 & UE-040641, Order 06 p. 42 ¶ 108 (Feb. 18, 2005).

contract as one of the items that <u>could</u> change during the course of this proceeding, and would therefore need to be included in PSE's power cost update on compliance.[46] Mr. Wetherbee's use of the word "could" is strange given that the expiration of the existing coal contract on December 31, 2019 is a fact certain.

Given PSE's vague answer to Staff DR No. 57, Staff issued DR No. 173 which asks PSE to either confirm or deny whether it plans to include the new Colstrip Units 3 and 4 coal contract costs in the compliance update in this case.[47] In its response, PSE says it has no plans to include the cost of the new coal contract in the compliance update and instead refers Staff to the Company's response to Staff DR No. 174.[48]

Q. So, based on PSE's response to Staff DR No. 174, new coal contract costs for Colstrip Units 3 and 4 will not be addressed in this GRC?

A. That appears to be the case. The Company plans to address both the prudency and cost of the new coal contract in a future Power Cost Only Rate Case (PCORC) or general rate case.

Q. Do you see problems with PSE's planned approach?

A. Yes. If, as Mr. Roberts claims, the new contract [redacted], [redacted] and these costs are not included in the Company's power cost baseline at the conclusion of this case, then large deferral balances in the PCA

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[46] Gomez, Exh. DCG-18 at 2.
[47] Gomez, Exh. DCG-19.
[48] *Id*., Gomez, Exh. DCG-20.

mechanism will accumulate thereby potentially triggering a coal fuel surcharge to customers at the end of the 2020-2021 deferral years.

Q. Can you offer the Commission a recommendation regarding the new coal fuel contract for Colstrip?

A. Not at this time. Until the details surrounding the new coal contract are revealed, Staff cannot offer a recommendation to the Commission nor can it quantify cost impacts. My testimony regarding the new coal contract is intended to inform the Commissioners so they at least have some idea of what to expect when (and if) a new coal contract is signed and executed by the Colstrip owners and Talen. As mentioned in my testimony, Staff has concerns over the cost and environmental impacts associated with a decision to enter into a new coal fuel supply contract for Colstrip.

IV. PROFORMA POWER COSTS

A. Pipeline Capacity Derate & Fixed Gas Transport Costs

Q. In examining the Company's fixed gas transport costs, did you find issues with the pipeline tariff rates used in the Company's workpapers?

A. Yes. I audited the Company's $3.8 million in pro forma fixed gas transport costs. In the workpapers of Mr. Paul Wetherbee, I found inconsistencies in the rates he used to calculate pro forma fixed gas transport costs when compared to the published rates of the various pipelines used by PSE to fuel its natural gas plants. In its response to

Staff DR No. 159, PSE corrects its fixed gas transport rates for Cascade Natural Gas, resulting in an increase to pro forma expense of $[redacted].[49] The Company has committed to correcting these rates when it updates its power costs on rebuttal.

Q. In Mr. Wetherbee's prefiled direct testimony, he describes PSE's derate of its fixed transport capacity along Enbridge's Westcoast gas transmission pipeline, does Staff support this adjustment?

A. No. The Company only applies the capacity derate in its forecast of pro forma gas optimization sales revenue. By reducing its contracted capacity on Westcoast, PSE decreases gas optimization sales revenues, thereby increasing net power costs by $[redacted].[50] PSE proposed derate is applied to specific months (April through November) for only one of its contracted pipelines, Westcoast.[51] The Company makes no adjustments to its other gas pipeline resources, citing a lack of data as its only reason.[52] PSE claims the adjustment to Westcoast's capacity is reasonable given the fact that the pipeline capacity is not fully available at all times due to planned and unplanned maintenance.[53]

Q. Does Staff support PSE's proposed derate of this resource?

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[49] Gomez, Exh. DCG-21.
[50] Wetherbee, Exh. PKW-20C, Worksheet Tab 27C-Gas MTM, Rows 86-125.
[51] Wetherbee, Exh. PKW-20C, Worksheet Tab 20C
[52] Wetherbee, Exh. PKW-1CT at 70:19-21.
[53] Wetherbee, Exh. PKW-1CT at 70:2-9.

A. No. First, since ratepayers are paying the full amount of this resource's fixed costs in rates, they should receive the full forecasted benefit from PSE's gas optimization and hedging activities (reward follows risk, benefit follows economic burden).[54] Second, reducing the rate year benefit to ratepayers of PSE's gas optimization activities for just one pipeline, based on only one year's data, is unreasonable and arbitrary in Staff's view. Third, PSE's proposed derate is at odds with statements it made about its Westcoast gas pipeline resource in Chapter 7 of its 2017 Integrated Resource Plan (IRP).

Q. How is PSE's proposed derate of its Westcoast capacity at odds with statements it made in its 2017 IRP?

A. At the time of its 2017 IRP, PSE stated that Westcoast capacity was fully contracted and was running at its maximum available capacity nearly year-round (limited by maintenance restrictions). According to the Company, this has resulted in adequate supply at Sumas in winter months and an excess in summer months.[55] PSE goes on to conclude; "PSE is comfortable with the notion that there will be adequate supplies at Sumas most times of the year with the increased capacity on Westcoast beginning in 2020, and that PSE would be able to compete (on price) to obtain sufficient supplies in peak periods, even with new loads."[56] Nothing contained in PSE's 2017 IRP gives any indication that the capacity along the Westcoast pipeline will

[54] *In re Petition of Puget Sound Energy for an Accounting Order Approving the Allocation of Proceeds of the Sale of Certain Assets to Pub. Util. Dist. #1 of Jefferson Cty*, Dockets UE-132027, Order 04 pp. 20-22 ¶ 32, 35 (Sept. 11, 2014).
[55] Gomez, Exh. DCG-22 at 3.
[56] Gomez, Exh. DCG-22 at 3.

somehow restrict the Company's future access to the low cost supplies of gas from Northeastern British Columbia. In fact, in its 2017 IRP, PSE makes mention of Enbridge's efforts to significantly increase both the capacity and reliability on the Westcoast pipeline. These capacity and reliability improvements for Westcoast are presently under construction and are projected by Enbridge to be in service by late-2021.[57]

Q. What is the net impact to power costs of correcting PSE's fixed gas pipeline rates and restoring the full contract capacity on Westcoast?

A. The net impact is zero. The increase in rate year expense from correcting the fixed pipeline rates is offset by the increased gas optimization revenues resulting from the restoration of the derated capacity on Westcoast.

Q. Gas Pipeline Optimization forecasting is an area of focus in the Avista power cost workshops, do you have similar concerns with PSE's forecast methodology?

A. Perhaps. The power cost workshop team has engaged a consultant to develop a scope of work which includes an in-depth review of Avista's gas optimization forecasting methodology. This report is expected to be completed in May or June 2020. Staff plans to leverage what it learns from the consultant's report in its future

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[57] *See* https://www.enbridge.com/projects-and-infrastructure/projects/tsouth-reliability-and-expansion-program.

evaluation of PSE's gas optimization forecast methodology including inter-company sales of gas and transfer pricing.

Q. Why is gas optimization forecasting a concern to Staff?

A. Because the differences between gas optimization forecasts compared to actuals appears to be a major source of power cost mechanism variance.[58] In PSE's 2018 Power Cost Adjustment Mechanism annual report, the Company's authorized expense for FERC account 456; Purchase/Sales of Non-Core Gas, was $(16.2) million. Actuals for this same account during the 2018 deferral year were $(69.5) million, a PCA variance of $(53.3) million.

Q. What about inter-company sales of gas and transfer pricing?

A. Another area of concern relating to gas optimization is the inter-company gas commodity transfer price recognized when utility gas and electric operations buy and sell gas to each other. In PSE's case, the transfer price methodology was arrived at through a settlement in the 1996 Puget Sound Power & Light and Washington Natural Gas merger case, UE-960195 (1996 Merger Case settlement).[59] In the 1996 Merger Case settlement, the parties agreed to a "<u>higher of market or the cost of incremental supplies with flexible take provisions</u>" as the transfer price for PSE's inter-company gas transactions.[60] While Staff was not able to audit the Company's adherence to the terms of the settlement in this case, it plans to do so in PSE's next

[58] Gomez, Exh. DCG-23.
[59] Gomez, Exh. DCG-24.
[60] *Id*.

GRC. Staff is also interested in understanding the effects that these inter-company transactions have on both the power cost and purchased gas adjustment mechanisms.

B. Wind Capacity Derates

Q. What is PSE proposing in this case?

A. PSE is proposing to once again derate the capacity factors of its wind resources in the AURORA model.

Q. Please describe the impact of these wind resource derates?

A. PSE derated the capacity factors of its established wind resources in the AURORA model which results in a reduction of 126,984 MWhs (14.5 aMW) of wind energy output, thereby increasing rate year power costs by approximately $1.0 million.[61] This reduction in modeled wind energy output for the rate year includes Klondike III, a PPA purchased from Avangrid Renewables.

Q. How did PSE arrive at its derated capacity factors for its wind resources in this case?

A. According to PSE, it used the results of a 2016 Vaisala Corporation (Vaisala) "operational reforecast" for all of its wind resources except for the Klondike III.[62] The Klondike III PPA relies on a production forecast from the project owner, Avangrid Renewables. For the newly acquired Skookumchuck Wind PPA, PSE

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[61] Gomez, Exh. DCG-25.
[62] Wetherbee, Exh. PKW-1CT at 71:2-10.

relied on the pre-production forecast from the project developer, Skookumchuck Wind Energy Project, LLC.

Q. What is an operational reforecast?

A. In 2016, PSE contracted with Vaisala Corporation (Vaisala) to provide an operational reforecast of rate year energy production at its Hopkins Ridge, Wild Horse, Wild Horse Expansion, and Lower Snake River wind projects. According to Vaisala, an "operational reforecast is an independent assessment of the future production of an operating project based on the historical production data and the climate."[63] According to Mr. Wetherbee, Vaisala's estimate of Hopkins Ridge's capacity factor relied on 10-years of historical production data.

Q. Did Vaisala actually use 10-years of data?

A. No. Vaisala was provided monthly generation averages by PSE which for Hopkins Ridge spanned a period of 128-months which is more than 10 years.[64] However, Vaisala removed 22 of those months to account for what it said was a break-in period, and also rejected months where the data indicated that plant availability fell below 90 percent. Later in the report, Vaisala provides its reforecast results citing it used 80-months of observed, normalized production data. Exactly which months were used, and by what criteria the additional 26 months were rejected, remain unexplained.

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[63] Gomez, Exh. DCG-26C at 4.
[64] Gomez, Exh. DCG-26C at 56.

Q. How did PSE arrive at capacity factors for its wind resources when they initially entered service?

A According to the Company, when each wind resource was placed in service, a preconstruction forecast was used to estimate wind production for each resource because there was no historical generation to inform a forecast.[65] These initial studies are generally described as an independent assessment of the wind climate and expected energy production of each wind project.

Q. What about the Skookumchuck Wind Project?

A At the same time PSE derated the output of its established wind resources, it added [redacted] MWh ([redacted] aMW) of wind generation output in the AURORA model from the newly acquired Skookumchuck Wind PPA.

Q. What capacity factor was used for Skookumchuck Wind project?

A. The capacity factor for Skookumchuck Wind project in AURORA is [redacted] percent.[66]

Q. Is this the first time PSE has derated the capacity factor of its owned wind resources?

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[65] Wetherbee, Exh. PKW-1CT at 71:13-14.
[66] Gomez, Exh. DCG-27C.

A. No. In the 2017 GRC, Staff opposed the same derates being proposed by the Company in this case. In the 2017 GRC, as in this case, PSE relies on the results of Vaisala's study.[67]

For Hopkins Ridge, the proposed derate in this case represents the second time the Company has adjusted downward the capacity factor of this project since it was placed in service in 2005. The same is true for Wild Horse (in service in 2006). For Wild Horse Expansion (in service in 2009) and Lower Snake River (in service in 2011), this case represents the Company's first proposed derate since the projects entered service. Over a span of 15-years the years, the Company has reduced the contribution of wind generation of all its owned and contracted wind plants in the AURORA model by 5.8 percent.

Q. Does Staff support PSE's capacity factor derates for its wind resources in this case?

A. No. Staff is unconvinced that persistent, lower than expected wind resource performance is entirely attributable to bad forecasting. Certainly, continued reforecasts by the Company have not seemed to resolve the issue. Here, Mr. Wetherbee offers up a stale, nearly four year old forecast which, after examining Table 14, gives Staff the impression that he lacks confidence in the very forecast he advocates for use in the model.[68] No, Staff thinks that the conversation should be broader as to the reason(s) behind why PSE's wind resources are not performing as

[67] Wetherbee, Exh. PKW-1CT at 71:20-21.
[68] Wetherbee, Exh. PKW-1CT at 73:8-74:5.

expected. Further, this conversation should not happen in the context of a GRC but should instead be included in the Company's upcoming IRP so they can explain to the Commission and other stakeholders why PSE's existing wind resources consistently over-promise yet, under-deliver.

Q. What do you mean by a broader conversation?

A. Staff referred to the Department of Energy's (DOE) 2018 Wind Technologies Report, Section 5; Performance Trends.[69] In the report, DOE examines the capacity factors of the U.S. wind fleet from a variety of perspectives. For example, capacity factors were examined by the age of the project, region and other factors such as: Project location; the quality of the wind resource at each site; turbine scaling and design; and performance degradation over time.[70] Additionally, the report compared wind resource capacity factors on a regional basis with Western U.S. wind projects' capacity factors averaging 36.6 percent.[71] All of PSE's wind projects' capacity factors are below that average benchmark.

This issue of underperformance needs to be explained by the Company in the context of the millions of dollars in maintenance spent annually to maintain the performance of these assets. Without this complete picture, Staff cannot support PSE's proposed derates at this time.

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[69] Gomez, Exh. DCG-28 at 53.
[70] Gomez, Exh. DCG-28 at 53.
[71] Gomez, Exh. DCG-28 at 56.

Q. How much O&M expense has PSE included in the rate year for its wind projects?

A. Mr. Roberts' testimony includes $32.7 million in wind generation O&M which is a $1.5 million reduction from the level of wind O&M expense in the 2017 GRC.[72] Wild Horse, Hopkins Ridge, and Wild Horse expansion are maintained by the turbine manufacturer, Vestas. Siemens maintains Lower Snake River.

Q. Did the Vaisala report examine turbine maintenance as a factor contributing to lower capacity factors for PSE's wind fleet?

A. No. Staff would expect that a proposal by the Company to derate its wind fleet in the AURORA model would be accompanied by evidence ruling out maintenance practices and turbine degradation as contributing factors.

Q. What is Staff's recommendation concerning PSE's derate proposal?

A. Staff recommends leaving the existing capacity factors in place until such time as PSE can address this issue more fully, either in its next IRP and/or GRC. Staff therefore respectfully asks the Commission to include along with its final order in this case a moratorium on capacity factor changes in AURORA until this issue has been addressed.

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[72] Roberts, Exh. RJR-1T at 31:15-19.

VI. TACOMA LNG DISTRIBUTION SYSTEM UPGRADES

Q. Does Staff agree with PSE's inclusion of $31.5 million of gas distribution system upgrades for the Tacoma LNG project into rate base?

A. No. In his prefiled direct testimony, Mr. Henderson describes three gas distribution upgrades that are required to connect the Tacoma LNG project with PSE's gas distribution system.[73] They are: Upgrade 1) – four miles of new 16-inch piping connecting Tacoma LNG to PSE's natural gas distribution system, Upgrade 2) – one mile of 12-inch high pressure piping and installation of the new Golden Given Limit station, and Upgrade 3) – Upgrades to the Frederickson Gate station. Two of these distribution system upgrades; Upgrade 1 and Upgrade 3 are included in the Company's test year rate base.[74] The yet to be completed Upgrade 2 has been postponed by the Company pending release of permits and determination of a new in-service date for the Tacoma LNG Project. These three distribution system upgrades are the same ones which the Company identified in the 2015 Tacoma LNG case, UG-151663, as being necessary to connect the Tacoma LNG project to its gas distribution system.[75] Given that the Tacoma LNG facility has yet to enter service, it is inappropriate to include the cost of these projects into rate base at this time.

[73] Henderson, DAH-1T at 5:1-7, 7:1-12, 8:3-7.
[74] Henderson, Exh. DAH-1T at 7:1-12.
[75] UG-151663, Anderson, Exh. LEA-1T at 2:10-3:4.

Q. Did PSE attempt to justify the addition of these distribution system upgrades by identifying a customer benefit outside those already identified in the 2015 Tacoma LNG project case?

A. Yes. Mr. Henderson's testimony identifies a hypothetical, but yet to be realized, peak-day benefit associated with a 28 percent increase to line pack.[76] How this purported peak day benefit compares to the benefits and synergies the Company had identified in its 2015 Tacoma LNG project case are not discussed in Mr. Henderson's testimony. For example, how does a 28 percent increase in line pack compare with the 66 MDth of injection capacity for peak-day use once the project is placed in service?[77]

Q. Did PSE attempt to include the capital costs of these two distribution system upgrades in rates before?

A. Yes. The Company sought to include the final costs of Upgrade 1 and 3 in rate base in its 2018 Expedited Rate Filing (ERF). Staff opposed their inclusion in that case also. In the interest of settling the ERF, the Company removed the capital costs of these upgrades from rate base.

Q. Are the amounts for Upgrade 1 and 3 the same in this case than in the ERF?

A. No. Comparing test year rate base amounts for Upgrades 1 and 3 in both the ERF and in this case reveals an unexplained difference. In the ERF, Ms. Catherine Koch

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[76] Henderson, Exh. DAH-1T at 7:13-8:2.
[77] UG-151663, Riding, Exh. CR-1HCT at 7:10-8:4.

testified that the final rate base amounts for Upgrades 1 and 3 totaled approximately $27.2 million.[78] In this case, Mr. Henderson's amounts for Upgrade 1 are $4.3 million higher than Ms. Koch's. The Company does not explain these differences.

Q. Has PSE announced an in-service date for the Tacoma LNG facility?

A. No. When specifically asked for a date in discovery as to when the Tacoma LNG facility would be completed and in operation serving customers, Mr. Henderson deflects the question and instead references the "in-service dates" of the three distribution system upgrades.[79] Additionally, Mr. Henderson provides no update as to when the Company expects its non-regulated customer; Totem Ocean Trailer Express, Inc. (TOTE), to have its ships ready to begin fueling with LNG.

Q. In the 2015 Tacoma LNG project case settlement, what did parties specifically agree to with regard to these three distribution system upgrades?

A. The Settling Parties acknowledged and agreed that the costs of distribution system upgrades associated with the Tacoma LNG project should be allocated in accordance with the principle of cost causation. Without the facility being in operation, including non-regulated LNG fuel supply service, an appropriate allocation of these distribution capital costs on a cost causation basis is not possible.

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[78] UE-180899, Koch, Exh. CAK-1T at 12:11-13:2.
[79] Gomez, Exh. DCG-29.

Q. Would Staff be supportive of a deferral of the cost of the two distribution system improvement until such time as the Tacoma LNG project is completed and in operation?

A. Yes, provided that the deferral period is reasonable and that PSE and TOTE have both committed to a commercial operation date for the facility. Additionally, Staff would also need to know when the Company expects to seek prudency of the costs relating to the construction, including the gas system distribution improvements required to flow gas in and out of the Tacoma LNG facility. In the meantime, the Company earns an Allowance for Funds Used During Construction (AFUDC) on both the cost of debt and equity funds used to finance the construction of the facility. In the 2015 Tacoma LNG project case, PSE had budgeted $[redacted] million in AFUDC.[80]

Q. Does this conclude your testimony?

A. Yes.

[80] UG-151663, Garratt, Exh. RG-3C at 7.