Exh. CSH-1CT
Dockets UE-170033/UG-170034
Witness: Christopher S. Hancock
CONFIDENTIAL VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-170033 and UG-170034 (*Consolidated*)**

TESTIMONY OF

CHRISTOPHER S. HANCOCK

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Funding of Colstrip Units 1 and 2 Decommissioning and Remediation; Payment Processing Cost Adjustments

June 30, 2017

CONFIDENTIAL PER PROTECTIVE ORDER

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher Scott Hancock. My business address is the Richard Hemstad Building, 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington 98504.

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

A. I am employed by the Washington Utilities and Transportation Commission (Commission) as a Regulatory Analyst in the Energy Regulation Section of the Regulatory Services Division.

Q. How long has the Commission employed you?

A. I have been employed by the Commission since January 2015.

Q. Would you please state your educational and professional background?

A. I graduated from New Mexico State University in 2013 with a Bachelor of Business Administration degree in Economics. In 2014, I graduated from New Mexico State University with a Master of Arts degree in Economics, specializing in Public Utility Policy & Regulation. Prior to my employment with the Commission, I interned at Southern California Edison's regulatory affairs department, and served six years in the United States Air Force before being honorably discharged.

Q. Have you previously testified before the Commission?

A. Yes. I have most recently testified as Staff's attrition study witness in Dockets UE-160228 and UG-160229. I also have testified on traditional modified historical test years and pro forma capital additions in Dockets UE-150204 and UG-150205, and served as Staff's witness on cost of service, rate spread, rate design, and decoupling in Docket UG-152286, a settled general rate case for Cascade Natural Gas.

II. SCOPE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present Staff's analysis on the following topics:

- The position Puget Sound Energy (PSE) is in with respect to other parties to ownership at Colstrip Generating Station (Colstrip;
- The merits of PSE's proposal to cover decommissioning and remediation costs of Colstrip Units 1 and 2;
- Staff's proposal to cover decommissioning and remediation costs of Colstrip Units 1 and 2;
- The recovery of costs for a fee-free credit and debit card program.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. Exhibit CSH-2C is PSE's confidential response to Staff Data Request 185. Exhibit CSH-3 is PSE's response to Staff Data Request 143. Exhibit CSH-4 is PSE's response to Staff Data Request 16. Exhibit CSH-5 is Montana's response to Staff Data Request 13.

III. OVERVIEW OF PSE'S DECISION TO SHUT DOWN COLSTRIP UNITS 1 AND 2

A. PSE Finds Itself in a Unique Position

Q. Please describe the co-owner dynamics present at Colstrip Generating Station.

A. There are four units at Colstrip GS. PSE and Talen (a wholesaler) jointly own Units 1 and 2; PSE, Talen, and four other public utilities own Units 3 and 4.

Talen currently operates all the Units at Colstrip GS. Talen has declared, in accordance with the ownership agreement for Units 3 and 4, that it will cease its role as operator in mid-2018. This requires the remaining five owners to find and agree upon a new operator.

Talen has also previously attempted to sell its share of ownership in Colstrip Generating Station, to no avail. In fact, one prospective buyer – Northwestern Energy, which already owns a portion of Colstrip Unit 4 – determined that Colstrip Units 1 and 2 had a valuation of *negative* $127.5 million.[1]

[1] Roberts, Exh. RJR-12 at 18.

Q. How does PSE's joint ownership of Colstrip Operating Units 1 and 2 with Talen affect PSE?

A. As a wholesale energy producer, Talen has no obligation to serve customers as regulated public utilities do. Talen is also exposed to competitive market pressures in ways that most regulated, vertically-integrated public utilities are not.

Talen's current contracts for long-term power are set to expire, and will place the company in a position where its costs exceed its projected revenues from operating. As a result, Talen has made the business decision to stop operating.

PSE's partnership with Talen exposes it to some of Talen's risks. Because Talen owns half of Unit 1 and half of Unit 2, PSE cannot operate either unit at full capacity on its own. Additionally, PSE would be responsible for the entirety of the large fixed costs of the both units, which would be spread over its current revenue stream. While PSE is not directly exposed to the same market pressures as Talen, it does incur knock-on effects through its partnership.

This ownership structure was originally created in order to ensure that both parties had a mutual interest in maintaining both units, and to spread the risk of one unit becoming unoperational. This risk-swapping rested on the presumption of a healthy partner.

PSE, and other UTC-regulated utilities, may face a similar situation in the future with Colstrip 3 and 4. Talen owns a portion of Colstrip Unit 3, and PSE shares ownership of both units with public utilities that are regulated by other state commissions, and that must operate under the laws of those states. Oregon, for example, requires one utility to cease acquisition of coal-based power by 2030, and another by 2035.

B. The Economic Viability of Colstrip Units 1 and 2 in the Absence of a Partner

Q. What has Talen said about the future of Colstrip Units 1 and 2?

A. On October 27, 2016, Talen's Director of Environmental Engineering Compliance, Mr. Gordon Criswell, declared to the US District Court for the District of Montana, under penalty of perjury, that the Settlement to close Colstrip Units 1 and 2 by July 2022 has no real bearing on the shutdown date of Colstrip units 1 and 2.[2] Mr. Criswell stated that Talen had concluded "…in advance of settlement that Units 1 and 2 would be expected to retire before mid-2022 as a result of economic and environmental regulatory factors unrelated to the ongoing litigation."[3] Additionally, he stated that "…independent of the Consent Decree, retirement of Units 1 and 2 also is part of Colstrip's compliance mechanism for the second phase of the Regional Haze program. The second phase of the Regional Haze program is scheduled to be implemented starting in 2018."[4] And even more candidly, Mr. Criswell stated that "…by agreeing to retire Units 1 and 2 in the Consent Decree, *Talen merely agreed to do what was going to be required anyway based on current and anticipated environmental regulations and economics*."[5] (Emphasis added.)

---

[2] *See generally* Roberts, Exh. RJR-16.
[3] Roberts, Exh. RJR-16, at 4 ¶ 11.
[4] Roberts, Exh. RJR-16, at 9-10 ¶ 20.
[5] Roberts, Exh. RJR-16, at 10 ¶ 21.

Talen's decision to cease operations at Colstrip Units 1 and 2 was based on a reasonable forecast that revenues would drop and costs would increase, thereby making the plant financially unviable. As a partner in ownership, PSE was married to and impacted by Talen's decisions. PSE cannot run the units economically on its own, and Talen has been unable to sell its ownership stake in the units.

Q. Have other Talen officers commented on shutdown of Colstrip Units 1 and 2?

A. Yes. On July 14, 2016, Talen Energy's Chief Financial Officer, Jeremy McGuire, testified before the Montana Energy and Telecommunications Interim Committee regarding the proposed acquisition of Talen by Riverstone Holdings. Mr. McGuire stated that "As we've said multiple times, our stated objective is to conclude our business in the state as quickly as reasonably possible."[6] Finally, Mr. McGuire stated "…economic challenges will very likely require the shutdown of Colstrip Station units 1 and 2 much sooner than the July 1, 2022 date specified in the statement."[7]

Q. Has the Commission previously considered the economic viability of Colstrip Steam Electric Generating Station?

A. Yes, the Commission considered Colstrip's economic viability in PSE's 2013 Integrated Resource Plan, docketed under UE-120767. Per the Commission's

---

[6] Roberts, Exh. RJR-13, at 2.
[7] Roberts, Exh. RJR-13, at 3.

instruction in its acknowledgment of PSE's 2011 IRP,[8] the Company produced a study of Colstrip's economic viability and provided that study to the Commission as a component of the Company's 2013 IRP. The Commission then provided comments on that study.[9] Those comments noted that under a purportedly low gas cost ($4.20 per MMBtu, a rather high estimate in hindsight)[10] and moderate environmental compliance cost scenario, Colstrip Units 1 and 2 would be uneconomical, even prior to consideration of stranded costs, site cleanup, or remediation costs. Indeed, in 15 of the 31 modeled cases, Colstrip Units 1 and 2 were uneconomical.[11]

The Commission noted: "…by the Company's own measure, all or some of the Colstrip generation units become uneconomic if we see lower natural gas prices, lower load growth, higher CO2 costs and/or higher environmental compliance cost."[12] This statement was footnoted, noting that IRP advisory groups had made "repeated requests" to independently assess the viability of Units 1 and 2. Additionally, the Commission specifically noted that the Base Scenario assumption of $6.05 per MMBtu was "in the higher range of expected costs for natural gas."

Further on, the Commission criticized PSE's load growth assumptions and cost-of-carbon assumptions. The Commission continued, commenting on

---

8 *Puget Sound Energy 2011 Electric and Gas Integrated Resource Plan*, Docket Nos. UE-100961 and UG-100960, Letter from Executive Director and Secretary Danner to Tom DeBoer, Attachment, at 6 (December 28, 2011).

9 *See generally Puget Sound Energy's 2013 Electric and Natural Gas Integrated Resource Plan*, Docket Nos. UE-120767 and UG-120768, Letter from Steve King to Ken Johnson, Attachment B (February 6, 2014) (hereinafter "Attachment B").

10 This "low" estimate later proved to be high; the EPA reports that spot prices at the Henry Hub for natural gas in the first three months of 2017 were $3.30, $2.85, and $2.88 respectively. https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

11 Attachment B at 8 (Figure 5-23).

12 Attachment B at 11.

environmental compliance cost assumptions, noting that "PSE did not attempt to study or quantify the remediation costs that the plant will incur at the end of its life. Any incremental remediation costs that may exist will increase Colstrip's levelized power cost."

In its summary, the Commission stated that the uncertainty around Colstrip's economic viability "could be harmful to PSE, its ratepayers and the broader public interest."[13] The Commission also suggested that PSE should consult with Commission Staff to consider "a closure or partial-closure plan"[14].

Q. Is there other evidence that Colstrip Units 1 and 2 would be unviable in the absence of a partner?

A. Yes. PSE has performed an analysis in which it considered an absent co-owner.[15] None of the three cases considered operations beyond 2022.

Restricting our review to the modeled circumstances in which no carbon tax is in effect, the most valuable of the three cases was one in which Colstrip Units 1 and 2 shut down early in 2017. A close second was the case in which PSE continued operation of Units 1 and 2 as "business as usual" (i.e., with a partner) until shutdown in 2022. Finally, the least viable case, by a significant margin, was one in which PSE

[13] Attachment B at 14.
[14] Attachment B at 15.
[15] Hancock, Exh. CSH-2C at 2-3.

becomes the sole operator of Colstrip Units 1 and 2, at 50% capacity each[16], and continues operations until 2022.

It is unlikely that the Commission would find Colstrip Units 1 and 2 to be cost-effective means of providing capacity and energy to PSE's customers with an absent co-owner of these plants.

Q. Is it prudent to close Colstrip Units 1 and 2?

A. This question is impossible to answer without having a better understanding of the replacement resources PSE has lined up. An Order in Dockets UE-920433, UE-920499, and UE-921262 (dated Sept. 27, 1994) declared that:

"When the company seeks to acquire resources, the Commission requires it to analyze any resource alternative under consideration utilizing up to date information, and adjusting for such factors as end effects capital costs, dispatchability, transmission costs, and whatever other factors its planning has disclosed need specific analysis at the time of a purchase decision."[17]

The company has yet to seek cost recovery of any resources to replace Colstrip Units 1 and 2. However, it is safe to say that Colstrip Units 1 and 2 will cost more to run in the near future than the company could find on the open wholesale market, and that the cost of operating Colstrip can be expected to increase as time

---

[16] For the purposes of analysis, PSE used **one** unit at **full** capacity as a proxy for two units at half capacity. Because operating two units at half capacity is less efficient than one unit at full capacity, this represents a best-case scenario of sorts for this case. *See* Hancock, Exh. CSH-2C at 2-3.

[17] *In re Petition of Puget Sound Power & Light Co. for an Order Regarding the Accounting Treatment of Residential Exchange Benefits; Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.; Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Docket Nos. UE-920433, UE-920499, and UE-921262, Nineteenth Suppl. Order, at 2 (Sept. 27, 1994).

goes on. This is evidenced by Talen's inability to operate an equal share of the plants in an economical fashion, by Talen's inability to find a buyer to take their place, and by the significantly negative asset valuation at least one potential well-informed buyer placed on Talen's coal-fired assets.

IV. REVIEW OF PSE'S PROPOSAL TO FUND DECOMMISSIONING AND REMEDIATION OF COLSTRIP UNITS 1 AND 2

Q. How are the costs of decommissioning and remediation usually recovered from customers?

A. Typically, these costs are recovered through depreciation expense. These costs are a component of what is known as "negative salvage value." Negative salvage value is the net cost of decommissioning and remediation activities ("cost of removal"), and the salvage value of the plant.

Normally, negative salvage value is calculated as a percentage of the cost of the retired plant; this figure is also known as the net salvage factor. This factor is calculated by evaluating historical experiences of similar plant. The experienced salvage value and cost of removal is divided by the original cost of the respective retired property, producing a factor that incorporates the effect of inflation.

While this is a rather crude tool, it typically suffices for ratemaking purposes. Negative net salvage has proven to be a useful tool in the past because accounting systems typically do not require recording accumulated depreciation reserve in any detail greater than the functional accounting group.

However, this approach is also dependent on the presence of a meaningful history for the particular type of plant, and it can prove inaccurate when the regulatory environment applicable to the plant has shifted. It is also sensitive to the age of plant at retirement. For these reasons, commissions and companies may move towards site-specific demolition and salvage estimates.

Both PSE and Staff adopt this latter approach in this proceeding. Additionally, both PSE and Staff "zero out" negative salvage value from the depreciation analysis, and instead consider separate means for covering the costs of decommissioning and remediation.

Q. What means has PSE proposed for recovery of decommissioning and remediation costs of Colstrip Units 1 and 2?

A. Ms. Barnard explains on page 83 of her direct testimony that PSE proposes to use existing regulatory liability accounts to address these costs. Namely, PSE proposes to re-purpose Treasury Grants and Production Tax Credits to cover the costs of decommissioning and remediation for Colstrip Units 1 and 2. The state legislature authorized this treatment by enacting SB 6248, and codifying it under RCW 80.84.[18]

Q. Under the legislation passed by the state legislature, can the funds set aside to cover decommissioning and remediation be used for other purposes?

---

[18] LAWS OF 2016, ch. 220, §§ 1-4, *codified at* RCW 80.84.010-.020.

A. No. Under RCW 80.84.020(2)(a), regulatory liabilities placed in a retirement account may not be used "for any purpose other than the funding and recovery of prudently incurred decommissioning and remediation costs".

A. Use of Treasury Grants

Q. Please describe how PSE's proposal to repurpose Treasury Grants would work.

A. Currently, the regulatory liabilities associated with the Snoqualmie Falls and Lower Baker River Treasury Grants act as a reduction to ratebase. Because of this, ratepayers pay a lower return on rate base than they would in the absence of the regulatory liabilities.

Additionally, the balance of the regulatory liabilities is amortized on a straight-line basis each year, which manifests as a reduction to the depreciation and amortization expenses that ratepayers currently pay.

PSE proposes to no longer amortize the regulatory liabilities, but to maintain their treatment as an offset to ratebase in a FERC 108 account. [19] In this proposal, customers still benefit from the reduced return on rate base, but no longer receive the benefit of reduced depreciation and amortization expenses.

Instead, PSE would hold the balance of the Treasury Grant regulatory liabilities and subsequently use it to fund the decommissioning and remediation expenses incurred over time. By adopting this treatment, PSE would fund decommissioning and remediation expenses using existing regulatory liabilities,

[19] Barnard, Exh. KJB-1T at 31:9-14.

rather than by more direct inclusion into rates through increased depreciation and amortization expenses. This change would introduce a shift in the generational benefits of the regulatory liablity.

The proposed use of these Treasury Grants would cover the vast majority of the expected decommissioning and remediation costs. To cover the remainder, PSE proposes using regulatory liabilities associated with Production Tax Credits.

B. Use of Production Tax Credits

Q. Please describe how PSE's proposed repurposing of Production Tax Credits would work.

A. PSE expects that the $95 million balance of the aforementioned Treasury Grants will not completely cover the estimated $107 million[20] net present value cost of the decommissioning and remediation expenses. To bridge this gap, the Company proposes to fund the estimated remaining balance of approximately $11 million with Produciton Tax Credits ("PTCs").

Currently, the Company has approximately $200 million of available and unclaimed PTCs; the recent availability of bonus depreciation has meant that the Company has not yet had taxable income against which to claim PTCs. Nonetheless, PSE plans to claim at least some of these PTCs in order to make its proposal viable.

[20] These estimates come from the PSE commissioned HDR study of decommissioning and remediation costs.

The benefit of these claimed PTCs would then be treated similarly to the Treasury Grants; the claimed PTCs would offset the value of PSE's rate base, slightly reducing customer costs for return on rate base.

Q. How are Production Tax Credits earned and claimed by the company?

A. PSE earns PTCs based on each megawatt-hour of eligible generation. Because PSE earns these credits on an energy basis, PSE passes their benefits on to customers through Schedule 95A on an energy basis as well.

Production Tax Credits offset the Federal Income Tax of the utility; a utility can claim such a credit on a return up to twenty years after the year in which the Production Tax Credit was produced. Production Tax Credits are redeemable by the company only when the company has taxable income to offset. Despite generating approximately $191 million in production tax credits, the company has not claimed these credits, in large part because bonus depreciation provisions have left the company with no taxable income.[21]

Under current treatment, if PSE claimed these PTCs, it would pass benefits along to its customers through Schedule 95, which confers those benefits to customers on an energy (kWh) basis. PSE's proposed change would confer benefits to customers on the same basis that production plant is allocated to customers – largely on a demand (kW) basis.

[21] Doyle, Exh. DAD-1T at 47:7-13, 48 lines 4-15.

C. Distributional Impacts

Q. Mr. Doyle claims that "The use of regulatory liablities to offset Colstrip Units 1 and 2 decommissioning and remediation costs resolves PSE's intergenerational equity considerations."[22] What is Staff's view of this claim?

A. "Resolves" is too strong of a claim. Mr. Doyle appears to be comparing the company's proposal to a hypothetical scenario under which a regulatory asset is created "for future decommissioning and remediation costs that would be included in rate base and amortized into the future."[23] Staff assumes that "into the future" is 2035, or some time beyond that.

As discussed in detail below, intergenerational tradeoffs are simply unavoidable on this matter; this is a product of the fact that the shutdown date (whether in 2018 or 2022, or some point in between) precedes the previously established depreciable lifespan through 2035. We are left with the task of mitigating intergenerational inequities, not resolving them.

Q. What are the distributional impacts of changing how Production Tax Credits are passed through to customers?

A. Adopting PSE's proposal would repurpose $11 million worth of benefits to customers that were created and distributed on an energy basis (the Production Tax Credits), and use that benefit to cover depreciation expenses that are charged largely

[22] Doyle, Exh. DAD-1T at 45:15-17.
[23] Doyle, Exh. DAD-1T at 44:17-19.

on a demand basis. This amounts to a redistribution of cost-allocation between customer-types – from high energy customers, to high demand customers.

V. STAFF'S PROPOSAL TO FUND DECOMMISSIONING AND REMEDIATION OF COLSTRIP UNITS 1 AND 2

Q. Please summarize Staff's proposal to fund the decommissioning and remediation of Colstrip Units 1 and 2.

A. Under Staff's proposal, approximately $63.9 million of Treasury Grant funds have their regulatory treatment altered. This $63.9 million is transferred to a separate interest-bearing acccount, where it no longer acts as an offset to rate base. The company would pay interest on this account at the authorized rate of return. Staff recommends that the Commission order the company to manage this account in a way that maximizes its after-tax value to customers.

Should the balance of this account grow such that it is greater than 125% of the estimated cost of decommissioning, demolition, and remediation[24], interest charges should temporarily cease.[25] This ensures that the company does not pay interest on an excessively large balance, and that PSE holds a reasonable balance in the account to fund decommissioning and remediation costs.

[24] Here "estimated cost of decommissioning, demolition, and remediation" is defined as the sum of the estimated costs of decommissioning and demolition (in current dollars), and the current book value of the Asset Retirement Obligations associated with Colstrip Units 1 & 2.

[25] Should the balance no longer hit the 125 percent cap at a future date, interest payments should resume.

Staff's recommendation results in ratepayers covering decommissioning and remediation costs, as estimated and measured in today's dollars, and PSE covering inflation of those costs, plus a contingency reserve.

Staff's proposal increases rate base by $69.6 million, and amortization expense by $2.4 million, resulting in a net operating income deficiency of $1.57 million. This proposal is shown as Adjustment 14.12 to Staff's electric revenue requirement model.

Q. How did Staff determine that $63.9M is the appropriate figure to repurpose from regulatory liabilities?

A. There are two sets of costs to consider: decommissioning and demolition costs, and remediation costs.

Staff adopts the Company's estimate of $4.2 million (in 2016 dollars)[26] for the cost of decommissioning and demolishing Colstrip Units 1 and 2. The Company's figure is a reasonable approximation of these costs, and is derived from the sum of two options presented in the most extensive of three estimates the Company solicited from experts in this field.[27]

Through Staff Data Request 143, Staff found that the current asset retirement obligation (ARO) for remediation at Colstrip Units 1 and 2 is $59,771,387.[28] These AROs, audited by a third party, represent the net present value of the currently-recognized cost of performing legally-required remediation activities. Staff's

[26] Roberts, Exh. RJR-1CT at 42:13-14.
[27] Roberts, Exh. RJR-1CT at 46:4-17.
[28] Hancock, Exh. CSH-3 at 1.

recommended amount to be repurposed ($63.9 million) is the **current**, audited ARO ($59.8 million) plus the decommissioning and demolition estimate ($4.2 million).

A. Interest

Q. Please summarize Staff's justifications for having the Company pay interest on this balance.

A. The repurposing of Treasury Grants in the manner described above ensures that today's ratepayers have paid for the currently recognized cost of decommissioning, demolition, and remediation, as expressed in today's dollars, rather than a projection of future dollars. This is consistent with the principle that consumers enjoying the benefits of a power plant should bear the cost of operation of that power plant.

The interest paid by PSE allows the balance to grow to meet the needs of funding these activities as inflation raises their cost, and as decommissioning and remediation charges to the account reduce the size of the balance.

There are other justifications for instructing the Company to pay interest as well. First, it is fair to customers, who are losing the "return on" and "return of" benefit of existing treatment of Treasury Grants. Second, directing PSE to pay interest on the balance appropriately includes PSE in bearing the burden created by early retirement of Colstrip Units 1 and 2. Finally, requiring interest ensures that PSE manages the size of the fund appropriately.

Q. Please elaborate on the first reason stated above, that it is fair to customers who are losing the benefits of the current treatment of Treasury Grants.

A. Under current treatment, Staff finds that customers benefit from the existing treatment of Treasury Grant regulatory liabilities in two ways: through a ratebase benefit, and through reduced depreciation/amortization expense. The net present value of these benefits through 2051 are $76 million in rate base benefit, and $59 million in depreciation/amortization expense benefit.

Customers experience a rate base benefit through these Treasury Grants because the Treasury Grants, as regulatory liabilities, act as an offset or a reduction to rate base. With a smaller rate base figure to apply the Company's authorized rate of return to, customers benefit from a lower "return on" component in revenue requirements. Put more concisely: under current treatment of these Treasury Grants, customers pay less in return on rate base, and less in depreciation expense.

Customers experience the depreciation/amortization expense benefit of Treasury Grants due to the existing rate base treatment of Treasury Grants as well. However, in this instance it is through the amortization of these regulatory liabilities. Again, because the regulatory liabilities act as a reduction to rate base, the amortization of them acts as an offset to depreciation/amortization expense. In the absence of the amortization of these regulatory liabilities, depreciation/amortization expense would increase by the size of the foregone Treasury Grants amortization.

Changing the regulatory treatment of these regulatory liabilities causes a change in the benefits passed on to customers. Adopting Staff's proposed treatment reduces the rate base benefit by $48 million (in NPV), from $76 million to $28 million. Under Staff's proposal, customers still experience a depreciation/amortization expense benefit, albeit at a lower level. The reduced depreciation/amortization expense benefits customers by $16 million (in NPV), compared to the current benefit of $59 million – an approximately $43 million change.[29]

Accruing interest on the repurposed balance of $63.9 million partially compensates customers for the lost benefits from repurposing a significant portion of the regulatory liabilities. Staff's proposal to require interest payments acts as a balance to the benefit that the Company receives from a higher rate base balance (on which customers effectively pay interest in the form of the authorized rate of return), and increased depreciation/amortization expenses.

Q. Please elaborate on the second reason stated above, that it includes PSE in bearing the burden created by early retirement of Colstrip Units 1 and 2.

A. The second reason interest should accrue on the balance is that doing so appropriately includes PSE in bearing the burden imposed on future ratepayers.

The intergenerational inequity die has already been cast on this matter – as Staff witness Mr. McGuire testifies, PSE's decision to retire Colstrip Units 1 and 2 drastically changes the lifespan, depreciation schedules, and book value of those facilities. Only a few years of operation now remain for Colstrip Units 1 and 2, and the principle of assigning costs to customers who benefit from the operation of those

[29] For comparison's sake, adopting PSE's proposed treatment reduces the rate base benefit to customers by approximately $5 million, from $76 million to $71 million, and completely eliminates the reduced depreciation/amortization expense benefit.

units weighs against assigning a significant portion of these costs to ratepayers beyond 2022. The accrual of interest on this balance, paid by PSE, ensures a more fair and equitable distribution of responsibility for these costs.

Q. Please elaborate on the third reason stated above, that it ensures that PSE manages the size of the fund appropriately.

A. A requirement that PSE pay interest on a given balance provides PSE with an incentive to minimize that balance, particularly the size of the repurposed Treasury Grants. This incentive is countered by PSE's desire to maximize the funding available for decommissioning and remediation activities.

Together, these incentives provide appropriate pressure on PSE to periodically review the cost of these activities. Additionally, it ensures that excessive funds are returned to customers promptly.

Coupled with the cap mechanism discussed below, interest payments ensure the availability of funds should costs exceed expectations. PSE provides an estimate of cost growth based on a 2.5% inflation rate that is used in the Company's IRP process.[30] Requiring interest payments results in having the Company assume the risk of cost growth.

Q. Is requiring interest payments from the Company punitive to the Company?

A. No. The basis of Staff's support for requiring interest payments is not in any way set in wrongs alleged of the company. As stated previously in this testimony, there is a

[30] Hancock, Exh. CSH-4 at 1.

large intergenerational inequity to manage. It is not fair for the four and a half years of ratepayers between 2018 and 2022, and future generations of ratepayers, to pay for the *entirety* of these costs – costs that normally would have been recovered from all generations of customers using Colstrip Units 1 and 2. Under Staff's proposal, the Company benefits from a higher rate base balance upon which to earn a return. It is best-positioned to bridge the gap between what is fair for ratepayers to pay, and the ultimate costs of decommissioning and remediation.

B. Generational Effects

Q. Has Staff reviewed the generational effects of its proposal, and of PSE's proposal?

A. Yes. Staff has developed a conceptual tool called a "customer-generation" to help illustrate the generational effects of PSE's proposal and Staff's proposal. Each customer-generation is a five year period, beginning in a given year, representing a generation of customers over that period of time.

Staff found the net present value to each customer-generation, at every year over the course of the time in which remediation activities at Colstrip Units 1 and 2 are expected to occur, under each of three scenarios.

The first scenario is PSE's proposal, the second scenario is Staff's proposal, and the third scenario is a counterfactual scenario. In the counterfactual scenario, which neither PSE nor Staff advocates for, no changes are made to the existing treatment of regulatory liabilities, and the estimated decommissioning and remediation costs of a given year are assigned to that year's ratepayers.

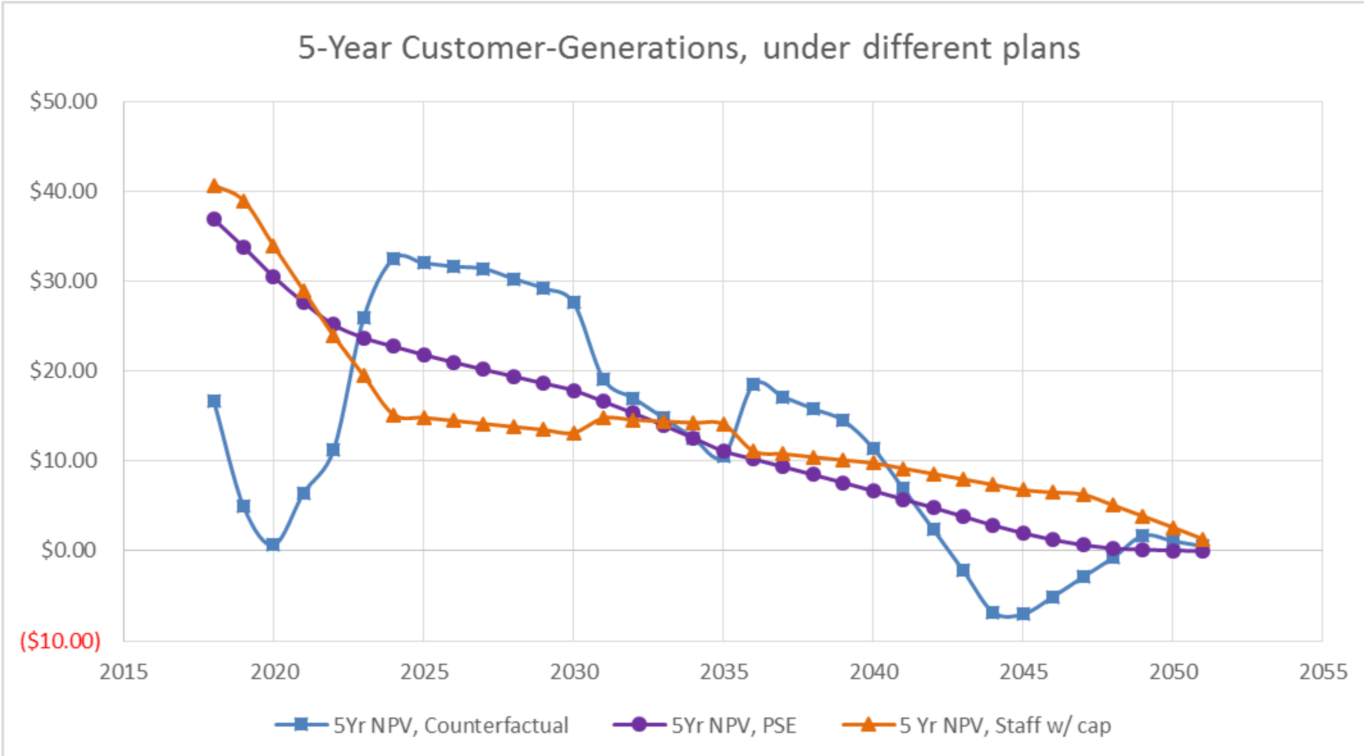
Q. Can you briefly summarize how PSE's proposal compares to that of Staff?

A. Yes. Below is a table containing figures of interest for three scenarios: PSE's proposal, Staff's proposal, and a counterfactual proposal that serves as a point of reference.

	Counterfactual	PSE	Staff
Rate base impact	$0 M	$0 M	$63.9 M
Rev reqmt impact	$5.0 M	$3.4 M	$2.5 M
No. of customer-generations advantaged	-	11	22
- NPV of interest	$0 M	$0 M	$27 M
- NPV of amort of Treasury Grants (TGs)	$59 M	$0 M	$16 M
- NPV of rev reqmt of remaining TGs	$76 M	$61 M	$28 M
- NPV of decom. & remed. expenses	($76 M)	$0 M	$0 M
- NPV of Prod. Tax Credits used	-	$10 M	-
- Total NPV of scenario	$59 M	$71 M	$71 M

Q. Please discuss the generational effects of these three scenarios.

A. The graph below illustrates the generational effects using customer-generations:



The blue line with the square marker represents the counterfactual scenario described above. This line is composed of the estimated costs of decommissioning and remediation activities assigned to the customer-generation, as well as the benefit of regulatory liabilities under current treatment, which is experienced by customers through reduced return on rate base and reduced depreciation/amortization expense. The rollercoaster-like shape of the line here makes apparent the unfairness of such an approach. The valleys of this line are instances where customer-generations experience large, "lumpy" expenses in the estimated schedule of decommissioning and remediation costs. In some instances these costs are so great that they completely overwhelm the benefits customers receive from existing treatment of regulatory liabilities.

By comparison, PSE's proposal (purple line, circle marker) is much fairer. Customer-generations before 2022 experience the greatest impact (as evidenced by the steeper slope of the line), and appropriately so, as those customers are the ones using the plant.

Finally, Staff's proposal is shown with the orange line and triangle markers. Staff contends that this is the most fair of these three scenarios. As with PSE's proposal, the customers through 2022 experience the greatest burden. However, the majority of customers beyond this point are better off under Staff's proposal; this is shown by the fact that more orange triangles are above purple circles than there are purple circles above orange triangles. In fact, 22 of the 33 customer-generations are better off under Staff's proposal than PSE's proposal.

C. Staff's Mechanism to Ensure a Reasonable Fund Balance

Q. Why has Staff proposed a 125% cap mechanism on the balance of this fund?

A. A cap of this nature serves the interests of both the company and of ratepayers. The cap serves PSE by ensuring that it does not pay interest on an unnecessarily large balance. The cap serves ratepayers by ensuring that PSE holds no more funds than necessary for decommissioning and remediation costs, and that PSE does not withhold those funds from customers for an unnecessarily long period.

Additionally, a cap set at 125% allows for a contingency reserve of sorts, in case costs exceed estimates.

Q. What is the 125% threshold applied to?

A. The 125% threshold is applied to the absolute value of the Asset Retirement Obligations (AROs) for Colstrip Units 1 and 2; the dollar figure for the cap is found as 1.25 times the value AROs at the given point in time.

Each year, AROs are recalculated, for a few reasons: new liabilities are discovered and recognized; some existing liabilities are sufficiently remedied; expected previous costs differ from experienced costs; and the discount rate appropriate for use in calculating AROs may change.

If Staff's recommendation is adopted, the Commission should require the Company to report each year the newly recognized value of AROs and the balance of the fund.

Q. How often would the cap be triggered under Staff's proposal?

A. Staff's analysis shows that the cap would not be triggered in the first 6 years of the plan, nor would it be triggered in the year 2035.[31] However, in all other years, the balance would exceed the 125% cap.

Consequently, the cap would severely reduce the size of interest payments the Company would otherwise make over this period of time. In many years, the Company would effectively not pay any interest on the balance, as doing so would

[31] To perform this analysis, Staff created a proxy for the changing value of AROs throughout the relevant period of time. The actual value of AROs will change over time due to increased qualifying remediation activities, or actual costs differing from estimated costs; these effects would change the level of the 125% cap, and possibly the years in which the cap is reached.

bring the balance in violation of the cap. Conceivably in some cases costs will be lower than anticipated, which would result in a refund back to customers.

Q. When a portion of a balance is to be refunded, how should that be accomplished?

A. Staff recommends that the amount exceeding the 125% threshold be "re-repurposed" in a subsequent ratecase, returning it to the current treatment of the Snoqualmie Treasury Grant, which acts as an offset to rate base and is amortized over the life of the plant. The Company would hold the refund amount in an account, and introduce the amount as an addition to the existing Treasury Grant balance in a future rate case.

D. Talen's Facility Closure Plan

Q. What is a Facility Closure Plan?

A. In Montana, Talen was party to an administrative order titled *Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Station, Colstrip, Montana*. This administrative order required Talen Montana to submit a Facility Closure Plan by August 3, 2017. Staff expects this document to be valuable to the record, as it will include estimates of closure and post-closure costs, and financial assurances from Talen Montana, amongst other items potential relevant to this matter.

Staff has required the State of Montana to provide the Facility Closure Plan upon receipt from Talen Montana through a data request.[32]

VI. PAYMENT PROCESSING COSTS ADJUSTMENTS

Q. Does Staff support Company adjustment 6.20?

A. Yes, albeit with minor changes. Staff adjusts the amortization period from one year, as the company proposes, to a three year period.

Q. Why does Staff propose to change the amortization period length?

A. Staff proposes to lengthen the amortization period to reduce the probability of over-collection. The company has proposed to recover the estimated balance of the deferral account ($2.5 million for electric, and $1.8 million for gas) over the course of one rate year. Should the company not file for a new general rate case almost immediately after the conclusion of this rate case, customers in the second, third, and later years after the implementation of rates from the conclusion of this case would be charged for the amortization of costs that would already be fully recovered.

Amortizing these costs over three years will allow PSE to recover from the customers on whose behalf these costs were incurred. While it is true that a one-year period would better ensure recovery from the cost-causing customers, the benefit gained on this measure is not worth the real possibility of overcollection that a one-year amortization schedule would introduce.

---

[32] Hancock, Exh. CSH-5 at 1, 2.

Q. What is the impact of Staff's recommendation on rate base and net operating income?

A. In electric service, Staff's recommendation has no impact on rate base, and creates a $3.69 million deficiency in Net Operating Income. In natural gas service, Staff's recommendation has no impact on rate base, and creates a Net Operating Income deficiency of $2.23 million.

Q. Does this conclude your testimony?

A. Yes.