

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

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

**CONFIDENTIAL RESPONSE TESTIMONY OF BRADLEY G. MULLINS
ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES
AND THE NORTHWEST INDUSTRIAL GAS USERS**

**CONFIDENTIAL PER PROTECTIVE ORDER IN
DOCKETS UE-170033 AND UG-170034**

(Confidential Information is Shaded)

TABLE OF CONTENTS
TO THE RESPONSIVE TESTIMONY OF BRADLEY G. MULLINS

I.	Introduction and Summary	1
II.	Early Retirement of Colstrip Units 1 and 2	4
a.	Accelerated depreciation is not a preferred way to account for early retirements	6
b.	Utility property that is impaired due to an early retirement decision is better considered an unrecovered investment	10
c.	Absent net benefits, early retirement losses should be shared between ratepayers and shareholders.....	13
d.	Amortization should roughly correspond to the timing of benefits	15
e.	Treatment of Microsoft load.....	22
f.	Colstrip Units 1 and 2 Summary	24
III.	Net Operating Loss Carryforward	26
IV.	Production Tax Credit Carryforward and Treasury Grant Amortization.....	32
V.	Pension Expenses.....	37
VI.	Plant Held for Future Use	40
VII.	Greenwood Natural Gas Explosion	44
VIII.	Environmental Remediation	46
IX.	Clean Air Rule Modeling.....	48
X.	Ardmore Substation	51

EXHIBIT LIST

- Exhibit No. BGM-2: List of Regulatory Appearances
- Exhibit No. BGM-3: Electric Services Revenue Requirement
- Exhibit No. BGM-4: Natural Gas Services Revenue Requirement
- Confidential Exhibit No. BGM-5C: Company Responses to Data Requests
- Exhibit No. BGM-6: Proposed Amortization Schedule of Early Retirement Costs
- Exhibit No. BGM-7: Company Response to ICNU Data Request No. 24
- Exhibit No. BGM-8: Ardmore Substation Ten-Year Planning Documents
- Exhibit No. BGM-9: Ardmore Substation Project Implementation Plan
- Exhibit No. BGM-10: Company Response to ICNU Data Request No. 91 and Attachment B (Lessons Learned)
- Exhibit No. BGM-11: Company Responses to ICNU Data Request Nos. 24 (Supplemental), 25, 85, 86, and 87

1 **I. INTRODUCTION AND SUMMARY**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite
4 400, Portland, Oregon 97204.

5 **Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE**
6 **TESTIFYING.**

7 A. I am an independent consultant representing energy and utility customers in jurisdictions
8 around the United States and am appearing in this matter—the 2018 General Rate Case
9 (“GRC”) filing of Puget Sound Energy, Inc. (the “Company” or “PSE”)—on behalf of
10 the Industrial Customers of Northwest Utilities (“ICNU”) and the Northwest Industrial
11 Gas Users (“NWIGU”). ICNU is a non-profit trade association whose members are large
12 customers of electric utilities located throughout the Pacific Northwest, including
13 customers of the Company. NWIGU is a non-profit trade association of approximately
14 40 industrial and commercial natural gas end users who have facilities in the states of
15 Oregon, Washington and Idaho, including customers of the Company.

16 **Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.**

17 A. I have a Master of Science degree in Accounting from the University of Utah. After
18 obtaining my Master’s degree I worked at Deloitte, where I ultimately specialized in
19 research and development tax incentives. Subsequently, I worked at PacifiCorp as an
20 analyst involved in power supply cost forecasting. I currently provide services to utility
21 customers on matters such as power costs, revenue requirement, rate spread and rate
22 design. I have sponsored testimony in regulatory jurisdictions throughout the United
23 States, including before the Washington Utilities and Transportation Commission

1 (“Commission”). A list of regulatory proceedings where I have sponsored testimony can
2 be found in Exhibit No. BGM-2.

3 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

4 A. I am responding to the Company’s request for an increase in revenue requirement in the
5 amount of \$148.6 million for electric services and \$23.0 million for gas services. My
6 analysis shows that the revenue requirement increase is more appropriately established at
7 \$28.4 million for electric services and \$5.3 million for gas services.

8 **Q. WHAT WAS THE NATURE OF YOUR REVIEW OF THE COMPANY’S**
9 **REVENUE REQUIREMENT?**

10 A. I have reviewed the Company’s filing and workpapers. I also issued discovery requests
11 and reviewed the Company’s responses to those requests, in addition to reviewing much
12 of the discovery from other parties in the proceeding.

13 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

14 A. The treatment of Colstrip Units 1 and 2 is a key driver of the electric rate increase the
15 Company seeks in this matter. In contrast to the Company’s proposal to treat the end of
16 life costs as ordinary depreciation expense, I believe it is appropriate to transition to end
17 of life accounting and spread the cost of the early retirement decision in a manner that
18 better corresponds to the timing of benefits received as a result of the decision to close
19 the facilities in 2022.

20 In addition to the issues surrounding Colstrip Units 1 and 2, I have identified
21 several other revenue requirement issues, which have been detailed in Table 1, below,
22 and discussed in detail in the sections of testimony that follow.

TABLE 1
Revenue Requirement Impacts of Proposed Adjustments
Revenue Deficiency / (Sufficiency) (\$000)

<u>Line</u>	<u>Description</u>	<u>Electric</u>	<u>Gas</u>	<u>Ref #</u>
1	Company Proposed	148,656	22,993	
	Adjustments:			
2	Cost of Capital (M. Gorman)	(27,999)	(9,648)	3.02
3	Colstrip 1&2 End of Life Acctg.	(3,467)	-	6.06 & IN-1
4	Net Operating Loss Carryfwd.	(7,594)	(1,293)	IN-2
5	Prod. Tx Cr. and Treas. Grants	(50,050)	-	IN-3 & 7.12
6	Pension Expense	(3,416)	(1,645)	6.15
7	Plant Held for Future Use	(5,062)	(368)	IN-4
8	Greenwood Natural Gas Expl.	-	(384)	IN-5
9	Environmental Remediation	(601)	(4,375)	6.19
10	Clean Air Rule Modeling	(20,238)	-	7.01
11	Ardmore Substn. Overrun	(1,784)	-	IN-6
12	Total Adjustments:	(120,212)	(17,713)	
13	Initial ICNU Recommendation	28,444	5,279	
	% Increase	1.45%	0.66%	

1 In addition, I have prepared Exhibits BGM-3 and BGM-4 providing additional
2 detail surrounding the revenue requirement calculations for electric and gas services,
3 respectively. The specific pro forma and restating adjustments impacted by the
4 recommendations detailed in Table 1 can be found in those exhibits. There were many
5 issues investigated by parties in the discovery phase in this case, so I might modify or
6 refine this recommendation in Cross-Answering Testimony based on issues other parties
7 have identified.

1 **II. EARLY RETIREMENT OF COLSTRIP UNITS 1 AND 2**

2 **Q. PLEASE PROVIDE SOME BACKGROUND ON THE DECISION OF THE**
3 **COMPANY TO RETIRE COLSTRIP UNITS 1 AND 2 EARLY.**

4 A. Pursuant to the July 12, 2016 Consent Decree lodged in the United States District Court,
5 District of Montana, the Company and Talen Energy agreed to permanently cease
6 operation of Colstrip Units 1 and 2 on, or before, July 2022.^{1/} Retirement of Colstrip
7 Units 1 and 2—which were originally placed into service in 1975 and 1976,
8 respectively—will represent a loss to the Company of approximately 307 MW of
9 capacity.^{2/}

10 **Q. WHAT SERVICE LIFE HAS THE COMMISSION ESTABLISHED WITH**
11 **RESPECT TO COLSTRIP UNITS 1 AND 2?**

12 A. The Commission approved the current service life of Colstrip Units 1 and 2 in Docket
13 UE-072300. In that proceeding the Commission approved a stipulation, where the
14 Company agreed with the recommendation of Staff and Public Council to establish a life
15 span estimate for the Colstrip facility of 60 years.^{3/} The 60 year service life estimate
16 corresponded to end of service life estimates of 2035 and 2036 for Colstrip Units 1 and 2,
17 respectively.

18 **Q. HOW HAS THE COMPANY PROPOSED TO ACCOUNT FOR THE EARLY**
19 **RETIREMENT DECISION?**

20 A. The Company proposes to account for the early retirement through ordinary depreciation
21 expenses. The Company also proposes to use production tax credit and treasury grant
22 balances to offset projected negative net salvage associated with these units. I discuss

^{1/} See Exh. No. RJR-18 at 6-7.

^{2/} See Puget Sound Energy, 2015 Integrated Resource Plan, Appendix K, at K-3.

^{3/} See WUTC v. Puget Sound Energy, Dockets UE-072300/UG-072301 (Cons.), Order 12 at ¶ 57 (Oct. 8, 2008).

1 this issue in more detail later in my testimony. With respect to accelerated depreciation
 2 of Colstrip Units 1 and 2, relative to the September 30, 2016 effective date of new
 3 depreciation rates, the Company proposes to reduce the remaining service life of these
 4 units from approximately 18.8 years and 19.8 years, respectively, to approximately
 5 5.8 years for both units. Relative to the existing service life, the Company's proposal
 6 represents a 72.0% and 73.4% reduction to the remaining service life of Colstrip Units 1
 7 and 2, respectively.

8 **Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THE COMPANY'S**
 9 **PROPOSAL?**

10 A. Table 2, below, details the revenue requirement impact of the Company's proposed use
 11 of accelerated depreciation to recover the early retirement cost of Colstrip Units 1 and 2.
 12 This includes the Company's proposal to assign production tax credit and treasury grant
 13 regulatory liabilities against the negative net salvage component of depreciation expense.

TABLE 2
Revenue Requirement Impact of Colstrip Accelerated Depreciation
whole dollars^{4/}

Depreciation Expense Impacts:		
311.00	Structures And Improvements	1,273,544
312.00	Boiler Plant Equipment	13,881,234
314.00	Turbogenerator Units	5,676,627
315.00	Accessory Electric Equipment	800,295
316.00	Miscellaneous Power Plant Equipment	219,128
	Pre Tax Net Operating Income	21,850,828
Proposed Rate Base Impacts:		
	Depreciation Reserve (6 months)	10,925,414
	ADIT (6 months)	(3,823,895)
	Rate Base	7,101,519
	Approx. Rev. Req. Impact	(22,055)

^{4/} There are a few relatively small accounts tracked in group assets, not impacted by the change in the probable service life estimate for Colstrip. See Exh. No. BGM-3 at 15 for a fuller list of Colstrip FERC accounts.

1 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE EARLY**
2 **RETIREMENT OF COLSTRIP UNITS 1 AND 2?**

3 A. For a number of reasons, accelerated depreciation is not a preferred way to account for
4 the early retirement of Colstrip Units 1 and 2. Since the Company has made a concrete
5 decision to proceed with the early retirement of Colstrip Units 1 and 2, I propose
6 maintaining the existing depreciation accrual and adopting end-of-life accounting
7 procedures to allow the Company with the opportunity recover its investment, while
8 protecting ratepayers against over compensating the Company. More specifically, I
9 recommend transferring the expected unrecovered investment balance as of July 1, 2022
10 into a regulatory asset. Under this proposal, the regulatory asset should be amortized
11 through a separate surcharge over the 12-year period ending in 2030, including a
12 provision for removal, decommissioning, and remediation.

13 **a. Accelerated depreciation is not a preferred way to account for early retirements**

14 **Q. WHAT IS THE PURPOSE OF DEPRECIATION IN PUBLIC UTILITY**
15 **RATEMAKING?**

16 A. In the context of utility ratemaking, depreciation serves at least two purposes.

17 First, a primary purpose of depreciation expense is to spread the cost of physical
18 properties in accordance with “the consumption of the useful service of physical
19 properties.”^{5/} From this perspective, depreciation may be viewed as temporal cost
20 allocation, spreading the cost of lumpy expenditures associated with infrastructure
21 investments over the period of time the assets are used. The costs are typically spread
22 over the probable service life of the property, measured in years—although allocation on
23 the basis of production service units, factors other than years, might be used in certain

^{5/} Marton et al., Engineering Valuation and Depreciation, 2nd Ed., at 223 (1953).

1 conditions.^{6/} In addition to conforming with the regulatory principle of
2 intergenerational equity,^{7/} use of depreciation expense in this context allows a utility to
3 set rates that are stable and durable over a long period of time.

4 Second, depreciation serves a purpose of affording a utility an adequate
5 opportunity to recoup from ratepayers its prudently incurred investments in fixed assets
6 over time.^{8/} From this perspective, depreciation represents the part of a utility's gross
7 investment which it is entitled to recoup in the future and on which it, in the meanwhile,
8 may be entitled to earn a fair rate of return.^{9/}

9 **Q. HOW IS DEPRECIATION EXPENSE ESTABLISHED FOR ANY GIVEN**
10 **OPERATING PERIOD?**

11 A. The principal difficulty with establishing depreciation expenses at any point in time is
12 determining how long a resource will provide useful service—or in the case of a
13 production service unit approach, the number of service units produced over the life of
14 the property. There are many different factors that affect the service life of a property.
15 For instance, some properties might wear out with use, whereas other properties might
16 wear out with time. There are also external factors which might affect the economic life
17 of a resource. Many long-lived assets might become uneconomical in the later stages of
18 their service lives due to the availability of improved types or changes in the markets for
19 production inputs. Similarly, public policy might cause a resource to be viewed as less
20 favorable, resulting in the retirement of that resource. These factors represent a source of

^{6/} Id.

^{7/} WUTC v. Avista Corp., Docket Nos. UE-080416/UG-080417, Order 08 ¶¶ 46-47 (Dec. 29, 2008).

^{8/} Bonbright et al., Principles of Public Utility Rates, at 270 (1988).

^{9/} Id.

1 uncertainty surrounding the useful service life of a property. Due to this uncertainty, the
2 depreciation expense established for any given period substantially relies upon judgment,
3 rather than rigid mathematical analysis, surrounding the probable service life of property.

4 **Q. SHOULD DEPRECIATION EXPENSE BE USED TO ACCOUNT FOR THE**
5 **UNEXPECTED, EARLY RETIREMENT OF UTILITY PROPERTY?**

6 A. No. A key aim of depreciation expense is to avoid the type of rate impacts that result
7 from amortizing the principal cost of an investment over a short period of time.

8 Consider the case of retirement accounting: it was once the case that some utility
9 rates simply accounted for plant costs at time of retirement.^{10/} Under the retirement
10 accounting method, the utility charges to production expense the entire amount of gross
11 plant, less salvage, in the year of retirement. For a number of reasons, however, utility
12 ratemaking transitioned away from retirement accounting, towards the use of
13 depreciation accounting. A key reason why retirement accounting is no longer used has
14 to do with the fact that, under that methodology, the cost of retired property is charged
15 wholly to the year of the retirement, instead of the years in which the property is used.
16 That is, the last period bears all of the burden associated with the original cost of the
17 property.

18 For similar reasons, adapting current depreciation expenses, as the Company
19 proposes with respect to Colstrip Units 1 and 2, is not a preferred way to account for its
20 early retirement decision. Similar to the retirement accounting methodology, using
21 depreciation expense to account for early retirement costs, as the Company proposes,

^{10/} See Marton et al., Engineering Valuation and Depreciation, 2nd Ed., at 216-17 (1953).

1 would result in all of the remaining unrecovered cost, including net salvage, being
2 allocated to production expense over a 4- to 5-year period of time.

3 It is not uncommon for the expected service life of a piece of property to change
4 from time to time. For instance, a utility might choose to invest additional capital in a
5 resource to extend the life of that resource. Similarly, a utility might choose not to invest
6 additional capital in the property and, instead, close the facility early.

7 Once the actual decision to retire the plant early has been made, however, the
8 primary purpose of depreciation—spreading the cost of the property over the period it is
9 used—becomes less important. In its place, the primary consideration from a ratemaking
10 perspective is, in my opinion, providing the utility with a reasonable opportunity to
11 recoup its capital investment, and with that consideration, it does not matter whether the
12 recoupment corresponds to the remaining service life of the utility property.

13 **Q. WHY IS DEPRECIATION EXPENSE UNSUITABLE FOR END OF LIFE**
14 **ACCOUNTING?**

15 A. In addition to the problems of spreading the unrecovered cost over a relatively short
16 period of time, depreciation expenses that are included in rates are not so precise as to
17 provide a good indication of the amounts that have actually been collected in rates with
18 respect to the Company's unrecovered investment and decommissioning and remediation
19 expenses. This is problematic because at the end of a resource's life, it may not be
20 possible to know the extent to which the Company has over or under collected with
21 respect to its investment.

22 Similarly, providing the Company with an accelerated return of its investment
23 also ensures a rapid decline of rate base balances. Under the Company's proposal,

1 ratepayers do not recognize the financial impacts of declining rate base that the Company
2 will experience in the test period. In this matter, the Company has used a bizarre measure
3 of average plant balances, that does not appropriately consider the declining balances.
4 The method the Company proposes, only reduces the plant balances for 6 months' worth
5 of accelerated depreciation expenses. By mid-year 2018, however, the actual plant
6 balances will have been subject to accelerated depreciation for 21 months. Thus, under
7 the Company's method ratepayers will pay the return on Colstrip Units 1 and 2 in 2018
8 based on inflated plant levels. Based on the Company's end of life accounting it will be
9 overcompensated, relative to these declining plant balances. In contrast, use of an
10 account outside of rate base, with a separately stated carrying charge, can serve to ensure
11 that the impact of these declining plant balances is appropriately reflected in rates over
12 time.

13 **b. Utility property that is impaired due to an early retirement decision is better considered**
14 **an unrecovered investment**

15 **Q. WHAT IS AN UNRECOVERED INVESTMENT?**

16 A. An unrecovered investment represents the cost of an asset not recovered at the end of a
17 resource's useful life, due to a premature retirement. The FERC uniform system of
18 accounts defines an unrecovered investment in Account 182.2, "Unrecovered plant and
19 regulatory study costs," as "significant unrecovered costs of plant facilities where
20 construction has been cancelled or which have been prematurely retired."^{11/}

^{11/} Prescribing a system of accounts for public utilities and licensees under the Federal Power Act, 18 C.F.R. § 101, 182.2.

1 **Q. DOES THE EARLY RETIREMENT OF COLSTRIP UNITS 1 AND 2**
2 **CORRESPOND TO THIS DEFINITION?**

3 A. Yes. The decision results in a reduction to the remaining service life of Colstrip Units 1
4 and 2 by approximately 73%. I view such a dramatic change to the service life represents
5 to be a premature retirement, which would appropriately conform to the definition of an
6 unrecovered investment detailed above.

7 **Q. HOW HAS END OF LIFE ACCOUNTING BEEN DONE IN THE PAST IN THE**
8 **NORTHWEST?**

9 A. Early retirements of base load generating resources are not entirely unprecedented in the
10 Northwest. The Trojan Nuclear Facility, which Portland General Electric retired early on
11 January 4, 1993, is probably the best example of an early retirement of a generation
12 facility in the Northwest.^{12/} Another recent examples is the Deer Creek Mine, which
13 PacifiCorp retired early from service in 2015, although only for purposes of Oregon and
14 Idaho rates.^{13/} The planned retirement of the Boardman Generating Station is another
15 example, although in that case, the decision to retire the facility was made well in
16 advance of the planned closure date, and thus, is less appropriately considered an early
17 retirement.^{14/}

^{12/} In the Matter of Revised Tariff Schedules for Electric Service in Oregon filed by Portland General Electric Company, Or. P.U.C. Docket No. UE 88, Order 95-322 at 1-4, 25-47 (Mar. 29, 1995). See In re the Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement, DR 10, Order 93-117 at 1 (Aug. 1993).

^{13/} In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction, Or. P.U.C. Docket No. UM 1712, Order 95-322 at 4-5 (May 27, 2015).

^{14/} In the Matter of Portland General Electric, Advice No. 11-07 Schedule 145 Boardman Adjustment Update, Or. P.U.C. Docket No. UE 230, Order 11-242 at 1-2 (July 5, 2011).

1 **Q. PLEASE PROVIDE AN OVERVIEW OF THE END OF LIFE TREATMENT**
2 **APPROVED IN OREGON FOR TROJAN.**

3 A. I view the circumstances surrounding the early retirement of Trojan's early retirement to
4 be not all that different from those of Colstrip Units 1 and 2. When Portland General
5 Electric put Trojan into commercial operation in 1975, the plant was expected to remain
6 in service until 2011. Trojan, however, was ultimately retired about 17 years earlier than
7 expected. While Portland General Electric, the operator of Trojan, had originally
8 proposed to retire the facility early in 1996, the Company ultimately decided that the
9 burden of operating the plant until 1996 was too great, resulting in the decision to retire
10 the generating plant even earlier in 1993.^{15/}

11 In the proceeding that decided the facility's regulatory treatment, the Oregon
12 Commission did not use accelerated depreciation to provide Portland General Electric
13 Company with a return of its capital invested in Trojan. Rather the Commission used a
14 balancing account, which spread the end of life cost of the investment over the expected
15 life of Trojan, prior to the early retirement, initially 17 years. This amortization period
16 was later reduced to about 10 years based on the way that the Oregon Commission
17 applied a net benefits principle. The Oregon Commission held that the amortization
18 period for undepreciated investments do not need to be tied to the life of the underlying
19 plant.^{16/} Rather, the Commission held that the amortization period for a regulatory asset
20 may be shorter or may be longer than the useful life of the underlying plant, depending
21 on what amortization period most equitably balances the interests of customers and the

^{15/} See In re the Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement, Or. P.U.C. Docket Nos. DR 10/UM 535 (Cons.), Order 93-1117 at 1-3 (Aug. 9, 1993).

^{16/} Re Portland Gen. Elec. Co., Docket Nos. DR 10, UE 88, and UM 989, Order 08-487 at 92 (Sept. 30, 2008).

1 utility.^{17/} In addition, the return on the balancing account was ultimately set at a long
2 term treasury bond rate, although a blend between treasury bonds and the utility's cost of
3 debt has also been used in Oregon for setting the carrying charge on unrecovered
4 investment accounts.

5 **Q. IS SIMILAR TREATMENT APPROPRIATE FOR COLSTRIP UNITS 1 AND 2?**

6 A. Yes. The Commission's decision about the appropriate period for amortization should
7 consider and be affected by the need to avoid increases in customer rates. Lengthy
8 amortization periods can lead towards more stable rates by allowing customers to pay
9 smaller amounts in rates over time.

10 **c. Absent net benefits, early retirement losses should be shared between ratepayers and**
11 **shareholders**

12 **Q. SHOULD CUSTOMERS NECESSARILY BEAR ALL COSTS ASSOCIATED**
13 **WITH THE EARLY RETIREMENT OF COLSTRIP UNITS 1 AND 2?**

14 A. No. In the Oregon cases, there was a great deal of discussion around the issue that
15 ratepayers should only be required to bear increased costs associated with early
16 retirement losses if the Company can demonstrate that an early retirement is the prudent
17 course of action, specifically by demonstrating that there are net benefits to customers
18 from early retirement.

19 **Q. HAS THE COMPANY DEMONSTRATED NET BENEFITS ASSOCIATED**
20 **WITH THE EARLY RETIREMENT OF COLSTRIP UNITS 1 AND 2?**

21 A. In ICNU Data Request ("DR") 103, the Company was requested to provide all documents
22 and analysis in its possession demonstrating that the early retirement of Colstrip Units 1
23 and 2 provides net benefits to customers.^{18/} The Company, however, provided no such

^{17/} Id.

^{18/} Exh. No. BGM-5C at 34 (The Company's Resp. to ICNU DR 103).

1 documents, and instead, referred to an analysis performed in WUTC Staff Data Request
2 185, which analyzed the effects of retiring Colstrip Units 1 and 2 even earlier than the
3 July, 1 2022 early retirement date.

4 Subsequently, in ICNU DR 111, the Company was asked to clarify whether the
5 Company believed that there were net benefits associated with the early retirement.^{19/} In
6 response, the Company did not provide any quantitative economic analysis, and instead,
7 simply referenced the testimony of Mr. Roberts as evidence that the early retirement
8 provided net benefits to ratepayers.^{20/}

9 The Company later supplemented its response to ICNU DR 111 on June 27,
10 2017,^{21/} just a few days prior to the deadline to file this testimony. As of this filing, I
11 have been unable to verify the workpapers to demonstrate that the closure produced a net
12 benefit, after considering the early costs. Notwithstanding, the Company forecast net
13 present value benefits of \$12.8 million over the period 2023 through 2038, and \$13.2
14 million over the period 2035 through 2042.^{22/}

15 **Q. DO YOU BELIEVE THERE ARE BENEFITS OF CLOSING COLSTRIP**
16 **EARLY?**

17 A. Yes. At current natural gas prices, and after considering all of the other costs and risks of
18 operating Colstrip Units 1 and 2, I think that there are probable benefits associated with
19 retiring Colstrip Units 1 and 2 early. What I have been unable to determine, however, is
20 whether, after accounting for all of the end-of-life costs, the early retirement provides a

^{19/} Id. at 39-40 (The Company's Resp. to ICNU DR 111).

^{20/} Id.

^{21/} Id. at 43 (The Company's 1st Supp. Resp. to ICNU DR 111).

^{22/} Id.

1 net benefit to ratepayers. If, through the closures, we are simply *cutting our losses*, then I
2 think it goes without saying that the Company should be a participant in those losses. If
3 the closures are projected to result in a net loss to ratepayers – meaning it would have
4 been more economical to continue running the units beyond 2022 – then this would be
5 evidence of an imprudent decision on the part of the Company

6 **Q. DO YOU PROPOSE TO APPLY THE SHARING PRINCIPLE IN THIS**
7 **MATTER?**

8 A. Not at this time. Based on the information the Company provided in its supplemental
9 response to ICNU DR 111, preliminarily showing a net benefit to ratepayers, I have not
10 proposed any sharing between ratepayers and shareholders with respect to the early
11 retirement losses. Notwithstanding, I may revise this recommendation after reviewing
12 the workpapers of the Company where it calculated the net benefits detailed above.

13 **d. Amortization should roughly correspond to the timing of benefits**

14 **Q. WHAT FACTORS ARE APPROPRIATELY CONSIDERED BY THE**
15 **COMMISSION WHEN EVALUATING THE UNRECOVERED INVESTMENT?**

16 A. The Commission would appropriately consider any number of factors when evaluating
17 the amortization of unrecovered investment in Colstrip Units 1 and 2. One principle that
18 is particularly important involves the matching of costs and benefits. That is, the costs
19 associated with a decision should generally be allocated in a manner that roughly
20 corresponds to those receiving the benefit from the decision. If the early retirement
21 decision primarily benefits customers subsequent to the retirement date, then that is
22 reason to extend the amortization of the unrecovered amounts to those customers
23 receiving the benefit. Such amortization, however, should be coupled with concerns of
24 conservatism and take into consideration all of a case's unique facts and circumstances.

1 **Q. WHEN ARE BENEFITS RECEIVED WITH RESPECT TO THE CLOSURE OF**
2 **COLSTRIP UNITS 1 AND 2?**

3 A. Absent the details behind the Company’s economic analysis of benefits associated with
4 the early closure, it is difficult to say when the benefits of the closure will be recognized
5 by ratepayers. Based on the qualitative analysis in Mr. Roberts’ testimony, nearly all of
6 the benefits will accrue to ratepayers taking service after Colstrip Units 1 and 2 are
7 retired. For example, Mr. Roberts states that, “[t]hrough a planned retirement, PSE and
8 Talen Montana could avoid future investment in environmental equipment upgrades on
9 Colstrip Units 1 & 2 while ensuring that Colstrip Units 3 & 4 would continue to run into
10 the future.”^{23/} Avoiding investments in environmental upgrades is a benefit to ratepayers
11 following the retirement, not to those ratepayers that happen to take service over the
12 remaining life of the resource. Similarly, ensuring that Colstrip Units 3 and 4 continue to
13 run, subsequent to the retirement of Colstrip Units 1 and 2, also benefits future ratepayers
14 who take service. Additionally, if one were to consider environmental benefits of the
15 closure, those social benefits would not be recognized until well after the retirement of
16 Colstrip Units 1 and 2, and certainly not while Colstrip continues to operate.

17 **Q. AFTER CONSIDERING ALL OF THESE FACTORS, WHAT AMORTIZATION**
18 **PERIOD DO YOU RECOMMEND?**

19 A. If the Commission were to use end of life accounting similarly to Trojan, I recommend
20 that Washington target paying for the entire balance of the Colstrip end of life costs by
21 December 31, 2029.

^{23/} Exh. No. RJR-1CT at 34:10-12.

1 **Q. HOW SHOULD NEGATIVE NET SALVAGE BE HANDLED?**

2 A. With respect to net salvage, Mr. Roberts indicates that decommissioning and remediation
3 expenditures will continue through 2051.^{24/} As will be discussed below, I disagree with
4 the use of the regulatory liability accounts associated with production tax credits and
5 treasury grants for purposes of funding decommissioning and remediation expenditures.
6 Ratepayers should not have to wait until 2051 to receive the benefits of those regulatory
7 liabilities. These lingering remediation expenditures are somewhat problematic in that it
8 is not in the best interest of Washington rate payers to fund remediation expenses today,
9 which the Company will not make for another 30 years. Accordingly, I only included
10 those remediation expenditures expected to be incurred through 2029, under the
11 assumption that any lingering expenditures will be funded through rates when made.

12 **Q. DO YOU HAVE ANY CONCERNS REGARDING THE PRUDENCE OF THE**
13 **REMEDATION EXPENDITURES DESCRIBED BY MR. ROBERTS?**

14 A. Yes. Based on my review, I have serious concerns regarding the decision of the
15 Company to use of a wet ash disposal method, versus dry disposal method for ash
16 disposal, at the Colstrip facility.

17 Wet disposal of ash at the facility in Colstrip involves pumping the waste from the
18 coal power plant scrubbers into an on-site pond, which then gets dredged and pumped
19 into the first-stage evaporation pond.^{25/} After the dredging, the ash settles and the water
20 gets reused or evaporated.^{26/} Finally, when the pond is full of ash and the water is

^{24/} Id. at 53:2-4.

^{25/} Id. at 15:17-21.

^{26/} Id. at 48:17-49:2.

1 completely evaporated, the surface is covered with topsoil and revegetated.^{27/} At the
2 Colstrip facilities, several ponds are used in both Stage I and Stage II. There are many
3 environmental risks are associated with the process, including groundwater
4 contamination.

5 Dry disposal of ash includes two stages of stabilization and fixation which
6 includes the use of dewatering devices, thickeners and vacuum filters.^{28/} Stabilization is
7 the physical treatment of the ash to improve ability to handle the ash and reduce the
8 moisture content of the ash using the thickeners.^{29/} Fixation is an extension of
9 stabilization that involves adding lime to the ash after stabilization and then allowing the
10 ash to cure causing the ash to become more like a low strength concrete material.^{30/} For
11 the Colstrip project, lime would be added to the dry filter cake from the vacuum filters to
12 make a cement like reaction that bonds the solids together.^{31/} This bond reduces
13 permeability and enhances the stability and ability to handle the dry waste.^{32/} This waste
14 would then be placed in trucks for transportation to the dump site – either at the facility
15 itself or a landfill.^{33/}

16 While dry ash disposal was the more expensive option based on what PSE knew
17 when it chose to proceed with wet disposal, it also did so knowing that wet disposal

^{27/} The Montana Power Company, Study of Alternate Ash Disposal Methods for Colstrip Units No. 1 and No. 2 at § 2.1 (Feb. 1985).

^{28/} Id. § 3.1.

^{29/} Id. § 3.1.1.

^{30/} Id. § 3.1.2.

^{31/} Id.

^{32/} Id.

^{33/} Id. § 3.4.

1 carried a significant risk of groundwater contamination and the associated costs, both
2 economic and social.^{34/}

3 When the Company made the decision to install a wet ash disposal system, it is
4 questionable whether it properly assessed the environmental impacts and their associated
5 costs. Now, in the remediation stage of Colstrip Units 1 and 2, there will be significantly
6 greater remediation expenditures due to the Company's decision—expenditures that
7 would have been avoided had the Company installed a dry ash disposal system. I plan to
8 review other parties' proposals on this matter and may support an adjustment in Cross-
9 Answering Testimony if another party makes a compelling argument for a prudence
10 disallowance.

11 **Q. IF THE COMMISSION DID IMPLEMENT A PRUDENCE DISALLOWANCE**
12 **WITH RESPECT TO REMEDIATION COSTS, WOULD YOUR PROPOSAL TO**
13 **USE END-OF-LIFE ACCOUNTING SIMPLIFY THIS ADJUSTMENT?**

14 A. Yes. One of the benefits of using the end-of-life accounting, as I am proposing, is that
15 the remediation costs are more closely tracked and a discrete disallowance could be
16 applied to the end of life account. In contrast, under the Company's proposal, the
17 remediation expenditures represent an indeterminant component of depreciation expense,
18 so it is difficult to discretely identify the effects of such a disallowance.

19 **Q. HAVE YOU PREPARED AN AMORTIZATION SCHEDULE TO ILLUSTRATE**
20 **YOUR PROPOSAL?**

21 A. Yes. Exhibit No. BGM-6 provides a proposed amortization schedule through 2029. As
22 can be seen, the analysis begins with the expected unrecovered plant balances as of July

^{34/} Id. at §§ 4.2, 4.3.

1 2022, as the Company provided in Attachment A of its response to ICNU DR 102.^{35/}

2 Amortization in my illustrative analysis is calculated at a levelized value, in order to
3 establish stable rates over the amortization period. I have also prepared an analysis
4 considering the impact of reclassifying the regulatory liability balances associated with
5 production tax credits into the balancing account.

6 **Q. SHOULD AMORTIZATION BE TRACKED THROUGH A SURCHARGE?**

7 A. Yes. Use of a surcharge will ensure that ratepayers do not over-, or under-pay, with
8 respect to the end of life costs. For the purpose of my analysis, I simply calculated the
9 revenue requirement impacts, as a component of overall revenues, so the Company would
10 have to design the new rates in its compliance filing, if the Commission chooses to adopt
11 treatment similar to Trojan in Oregon.

12 **Q. WHAT CARRYING CHARGE IS APPROPRIATELY APPLIED TO THE**
13 **UNRECOVERED INVESTMENT BALANCE?**

14 A. The Company will be guaranteed recovery of any amounts accrued to the end of life
15 account. Accordingly, the risk associated with the return of the unrecovered investment
16 balance is not the same as the risk associated with other investments reflected in the
17 operations of the Company. This leads me to be of the opinion that a full carrying charge
18 on the unrecovered investment balance would overcompensate the Company, relative to
19 the risk associated with the regulatory account. Notwithstanding, the Company would
20 have earned a return on the entire plant balance through 2022, it maintained the status
21 quo probable service life. To address these notions, my analysis has included two
22 separate carrying charges. Over the period where Colstrip Units 1 and 2 remain

^{35/} Exh. No. BGM-5C at 52-53 (The Company's Resp. to ICNU DR 102).

1 operational, I have included a carrying charge on the balance equal to the full cost of
2 capital. Once Colstrip ceases operation, however, and is no longer used and useful in
3 providing utility services to ratepayers, I assume assumes a carrying charge equal to the
4 cost of debt. In the retirement year, I used a carrying charge that is a blend of these two
5 rates to reflect the partial year operations of the facility. Finally, the amortization is then
6 levelized to provide a consistent level of recovery in each year of the amortization period.
7 This levelization was achieved by using “goal seek,” calculating the amount of equal
8 amortization necessary for the account balance to be fully amortized by the proposed
9 December 31, 2029 date.

10 **Q. SHOULD THE COMPANY BE ALLOWED TO INCLUDE ADDITIONAL**
11 **INVESTMENTS IN THE UNRECOVERED INVESTMENT BALANCE?**

12 A. To the extent that the Company must make additional investments in order to keep the
13 plant operational until 2022, those amounts should be carefully reviewed. For example, it
14 may not make sense to make a \$5 million investment in the facility to keep the facility
15 operational for another year, if there are no commensurate dispatch benefits associated
16 with doing so. This is a difficult problem, because with each additional investment, it
17 becomes more costly to retire the facility early.

18 In response to ICNU DR 102, the Company indicated that it will make \$42.3
19 million in additional expenditures through the remaining life of Colstrip Units 1 and 2.^{36/}
20 Thus, under the Company’s proposal to use accelerated depreciation over the remaining
21 life, these new capital additions will remain outstanding at the retirement date. This
22 means that even if the Company’s proposal is adopted, there will still be a great deal of

^{36/} Exh. No. BGM-6 at 3.

1 additional costs that will need to be recovered following the retirement. This is
2 problematic because, with the use of accelerated depreciation, it won't necessarily be
3 clear how much ratepayers have contributed to these residual balances.

4 Accordingly, I recommend that the Company be allowed to accrue additional
5 capital investments into the unrecovered investment balance, subject to review by the
6 Commission of every capital dollar spent, in relation to the continued operation of the
7 plant through the 2022 timeframe. If it is determined that it would have been less costly
8 to ratepayers to avoid a capital expenditure, and instead retire the facility prior to the
9 2022 date, the additional amounts should not be recoverable by the Company. Stated
10 differently, if the Company is not able to demonstrate a net benefit for the capital, it
11 should not be reflected in the account. My amortization schedule excludes any provision
12 for future capital expenditures. As those expenditures are incurred, the account balances
13 would change, requiring adjustments to the amortization amount.

14 **e. Treatment of Microsoft load**

15 **Q. PLEASE PROVIDE SOME BACKGROUND ON MICROSOFT LOAD.**

16 A. In Docket UE-161123, the Company submitted an application which would allow
17 Microsoft to take electrical services from an alternative energy supplier.^{37/} Parties in that
18 proceeding reached a settlement, which is currently under consideration before the
19 Commission. I represented ICNU and filed testimony supporting the settlement that was
20 reached in that matter.^{38/}

^{37/} WUTC v. Puget Sound Energy, Docket No. UE-161123, Settlement Stipulation and Agreement (Apr. 11, 2017).

^{38/} Docket No. UE-161123, Exh. No. BGM-1T at 1:23-2:8.

1 **Q. WHAT DID THE STIPULATION PROVIDE WITH RESPECT TO THE**
2 **TREATMENT OF COLSTRIP UNITS 1 AND 2?**

3 A. The stipulation stated that it did not resolve or address any issue with respect to
4 Microsoft's potential liability for decommissioning and remediation costs associated with
5 Colstrip Units 1 and 2.^{39/}

6 **Q. HOW WAS THE TRANSITION FEE CALCULATED?**

7 A. The exit fee was calculated over the five-year period ending in 2022.

8 **Q. WHAT DO YOU PROPOSE WITH RESPECT TO MICROSOFT LOAD?**

9 A. The benefits associated with Microsoft's departure only considered five years of
10 Colstrip's remaining eighteen-year life. Accordingly, it is appropriate for Microsoft to be
11 required to pay for no more of five of eighteen years, approximately 27.8%, of its share
12 of the remaining unrecovered investment in Colstrip Units 1 and 2. Within the context of
13 the surcharge identified above, the amount allocated to Microsoft would represent 27.8%
14 of its fully allocated share.

15 **Q. WHY IS THIS TREATMENT APPROPRIATE?**

16 A. This is consistent with the established ratemaking principle that costs are most
17 appropriately borne by ratepayers in proportion to the benefits received by ratepayers.
18 Had the transition payment agreed to in Docket UE-161123 been calculated over the
19 existing remaining 18-year life, Microsoft's departure would have been a benefit to
20 customers. Measured over 20 years, the Company had calculated that the departure of
21 Microsoft represented an approximate \$23.3 million benefit to customers. If the
22 transition fee had been calculated over the entirety of the remaining depreciable life of

^{39/} Docket No. UE-161123, Settlement Stipulation and Agreement at 4 (Apr. 11, 2017).

1 Colstrip, the transition payment would have been as a negative number, representing a
2 payment due from remaining ratepayers to Microsoft.

3 The period over which the Company calculated the transition payment, however,
4 did not correspond to the remaining life of Colstrip Units 1 and 2, and was restricted to a
5 five-year period, in an arguably arbitrary manner. In my testimony in that matter, I
6 discussed why it was not reasonable for Microsoft not to be provided with the benefit of
7 the avoided capacity costs for Colstrip Units 1 and 2 that remaining customers will
8 recognize as a result of its departure.^{40/} Since Microsoft did not get credit for the benefits
9 that will arise through avoiding replacement capacity for Colstrip Units 1 and 2, it should
10 not have to pay all of the unrecovered cost that would otherwise have been incurred after
11 the transition payment.

12 **f. Colstrip Units 1 and 2 summary**

13 **Q. PLEASE SUMMARIZE YOUR TESTIMONY ON COLSTRIP UNITS 1 AND 2.**

14 A. Accelerated depreciation is not a preferred way to perform end of life accounting.
15 Accordingly, I recommend that the existing depreciation accruals be maintained, and that
16 the expected unrecovered investment balance as of July 2022 be immediately transferred
17 to a regulatory asset and amortized over the period 2018 through the end of 2029,
18 including a provision for decommissioning and remediation. Any additional capital
19 additions at Colstrip Units 1 and 2 should not be recoverable by the Company unless
20 reviewed and approved by the Commission for inclusion in the regulatory asset balance.

^{40/} Docket No. UE-161123, Exh. No. BGM-1T at 2:9-3:21.

1 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

2 A. My recommendation impacts two different restating adjustments. First, I have reduced
3 the revenue requirement impact of restating adjustment 6.06, "Depreciation Study," by
4 approximately \$22.5 million. This change reverts to the existing depreciation accruals
5 for Colstrip Units 1 and 2. Second, I have created a new restating adjustment IN-1, to
6 account for the other impacts of my recommendation. Under this adjustment, I have
7 removed from rate base the plant balances that I propose be transferred to the end of life
8 regulatory asset. This removal is necessary because the cost of capital is separately
9 handled in the account. Adjustment IN-1 also applies amortization of the regulatory
10 balance, which includes amounts representative of the Company's return on the
11 transferred balances.

12 The net revenue requirement impacts of all of these changes is modest, resulting
13 in only a \$3.5 million reduction to revenue requirement for electric services. The real
14 benefit of this proposal for ratepayers, however, is freeing up the very significant
15 production tax credit regulatory liability for amortization, which will be discussed below.
16 In that context, I also performed a sensitivity on page 2 of Exhibit No. BGM-6 to
17 determine the impacts of reclassifying a portion of the production tax credit regulatory
18 liability balance to the Colstrip Units 1 and 2 end of life account. It shows that it would
19 only be necessary to transfer 86.4% of the regulatory liability balance, in order satisfy
20 the entirety of the balance through 2029. Thus, this sensitivity may serve as an
21 interesting alternative for the Commission consider, that would result in no rate impact
22 associated with the early retirement through 2029.

1 **III. NET OPERATING LOSS CARRYFORWARD**

2 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO NET**
3 **OPERATING LOSS CARRYFORWARDS?**

4 A. The revenue requirement workpapers of Ms. Barnard assume a net operating loss
5 carryforward balance of \$273.8 million as of September 30, 2016. Based on that balance,
6 the Company includes tax-effected amounts of \$74.0 million and \$12.6 million as an
7 increase to rate base, for gas and electric services, respectively. The carryforwards were
8 generated in tax years 2009, 2010, 2012 and 2013.

9 **Q. WHAT IS A NET OPERATING LOSS CARRYFORWARD?**

10 A. If a corporation reports a net operating loss for tax accounting purposes, the net operating
11 loss may be “carried-forward” and used as a deduction against future years’ tax
12 liability.^{41/} Application of a net operating loss carryforward is limited to the 20 tax years
13 subsequent to the tax year in which the net operating loss was generated.^{42/}

14 Similarly, a net operating loss can also be “carried-back” and used to offset tax
15 liability in prior tax years, through the filing of an amended return.^{43/} Application of a
16 net operating loss carryback is limited to the two tax years prior to the tax year in which
17 the net operating loss was generated.^{44/}

18 **Q. HOW ARE NET OPERATING LOSS CARRYFORWARDS HANDLED FOR**
19 **FINANCIAL ACCOUNTING PURPOSES?**

20 A. For financial accounting purposes, a net operating loss carryforward gives rise to a
21 deferred tax asset. Generally accepted accounting principles establish the creation of a

^{41/} Internal Revenue Code (“I.R.C.”) § 172(a).

^{42/} I.R.C. § 172(b)(1)(A)(ii).

^{43/} I.R.C. § 172(a).

^{44/} I.R.C. § 172(b)(1)(A)(i).

1 deferred tax asset, or deferred tax liability, to the extent that there are differences between
2 the years in which transactions affect taxable income and the years in which they enter
3 into the determination of pretax financial income.^{45/} This concept is generally referred to
4 as a “temporary difference.”

5 For income tax accounting, the U.S. Treasury will not issue a refund for the
6 amounts that one might consider as “negative taxes” in a year in which an entity incurs a
7 net operating loss. Notwithstanding, based on the provisions discussed above, the entity
8 may use the loss as a deduction against future years’ taxable income.

9 For financial accounting purposes, however, an entity may claim a tax benefit in
10 the year in which a net operating loss is incurred, based on the expectation that the loss
11 may be used to reduce tax liability in a future tax year. A net operating loss
12 carryforward, therefore, presents an instance of a “timing difference.” In this situation, a
13 benefit is reflected in financial results that will not be received through reduced tax
14 liability until some future period. Under SFAS 109, this financial tax benefit represents a
15 deferred tax asset that is ultimately amortized to tax expense in the year that the net
16 operating loss carryforward deduction is claimed on the entity’s tax return.

17 **Q. DO THE SAME PRINCIPLES APPLY WHEN ACCOUNTING FOR INCOME**
18 **TAXES FOR RATEMAKING PURPOSES?**

19 A. The same general principles apply; however, the starting point is different. Utility rates
20 in Washington are not based strictly upon the financial accounting operating results.
21 Utility rates are based upon operating results that have been modified through a
22 combination of restating and pro forma adjustments.

^{45/} Statement of Financial Accounting Standard (“SFAS”) 109, Accounting for Income Taxes at 4-5.

1 The establishment a “temporary difference,” therefore, takes on a slightly
2 different character for ratemaking purposes than it does for financial accounting
3 purposes. For ratemaking, a “timing difference” is a measurement of differences between
4 the years in which transactions affect taxable income and the years in which they enter
5 into the determination of rates.

6 **Q. IS A NET OPERATING LOSS CARRYFORWARD APPROPRIATELY**
7 **CONSIDERED A DEFERRED TAX ASSET FOR RATEMAKING?**

8 A. It depends. For financial accounting purposes, the deferred tax asset arises because the
9 current tax expense in a historical period was negative, resulting in a benefit on prior
10 years’ financial statements. For ratemaking purposes, however, current taxes are
11 established based on normalized income and expenses, and ratepayers generally do not
12 receive the benefit of negative current tax expenses. For this reason, I disagree with the
13 Company that net operating loss carryforwards are appropriately considered as a
14 component of revenue requirement, although there may be some hypothetical situations
15 where a net operating loss carryforward is appropriately considered for ratemaking.^{46/}

16 **Q. HOW ARE DEFERRED TAX ASSETS AND DEFERRED TAX LIABILITIES**
17 **CONSIDERED FOR RATEMAKING PURPOSES?**

18 A. Deferred tax assets and liabilities are, where appropriate, reflected in the allowance for
19 deferred income taxes (“ADIT”). In revenue requirement, ADIT is basically considered a
20 source—or use—of “no-cost capital.”

21 If a utility recognizes a cost for tax accounting purposes earlier than that cost
22 would otherwise be recognized for ratemaking purpose, ratepayers are effectively

^{46/} If rates have historically been calculated under the assumption of a current tax loss, that may be an example of when it is appropriate to include a net operating loss carryforward in rates.

1 provided with a carrying charge on the temporary differences, through a reduction to rate
2 base. Similarly, to the extent that a utility recognizes a cost for tax accounting purposes
3 later than the cost would otherwise be recognized for ratemaking purposes, ratepayers
4 pay a carrying charge on the temporary difference, through an increase to rate base.

5 Depreciation expense is the most common example. For tax purposes, a utility is
6 often provided with the ability to depreciate property using *liberalized*, accelerated
7 depreciation methodologies. For regulatory purposes, however, depreciation expense is
8 calculated based largely on straight line methodologies—albeit calculated in complex
9 depreciations studies—which typically assume longer lives. Thus, a utility may claim tax
10 benefits associated with the cost of utility property that is, in most instances earlier than
11 reflected in the tax expenses uses for ratemaking. To account for the difference, the cash
12 benefit received by the utility as a result of the different depreciable lives is treated as a
13 source of no-cost capital, and deducted from rate base through ADIT.

14 **Q. WHAT GUIDANCE DOES THE INTERNAL REVENUE SERVICE PROVIDE**
15 **WITH RESPECT TO THE TAX EXPENSES USED IN RATEMAKING?**

16 A. One might think that state utility ratemaking would fall outside of the purview of the
17 Internal Revenue Service (“IRS”). The IRS, however, does have limited oversight of the
18 accounting for income taxes associated with public utility property. Under
19 I.R.C. § 168(f), a public utility is required to calculate rates excluding the current tax
20 impacts of accelerated depreciation. The Treasury regulations make it very plain that this
21 requirement applies only to accelerated depreciation:

22 The normalization requirements of section 167([f]) with respect to public utility
23 property defined in section 167(l)(3)(A) pertain only to the deferral of Federal
24 income tax liability resulting from the use of an accelerated method of
25 depreciation for computing the allowance for depreciation under section 167

1 and the use of straight line depreciation for computing tax expense and
2 depreciation expense for purposes of establishing cost of services and for
3 reflecting operating results in regulated books of account. Regulations under
4 section 167(l) do not pertain to other book-tax timing differences with respect
5 to State income taxes, F.I.C.A. taxes, construction costs, or any other taxes and
6 items.^{47/}

7 With respect to timing differences, other than those caused by accelerated
8 depreciation, the Commission has a great deal of latitude in evaluating whether the
9 particular timing difference truly represents a source—or use—of no cost capital, which
10 is appropriately included as a tax asset in rate base for ratemaking purposes.

11 **Q. HAS THE IRS PROVIDED ANY SPECIFIC GUIDANCE ON NET OPERATING**
12 **LOSS CARRYFORWARDS?**

13 A. The IRS has issued several private letter rulings on this matter. For example, PLR
14 201709008 was issued earlier this year, where the IRS affirmed that a net operating loss
15 caused by accelerated depreciation was appropriately included in rate base.

16 **Q. WHAT DO YOU PROPOSE WITH RESPECT TO THE COMPANY'S NET**
17 **OPERATING LOSS CARRYFORWARD?**

18 A. While I tend to disagree with the IRS's position on this matter because it is not
19 necessarily possible to isolate accelerated depreciation as the sole driver of the net
20 operating loss carryforward, I propose to conform with the above PLR, however, to
21 adjust the net operating loss carryforward balance to reflect more recent information, as a
22 pro forma adjustment. The Company's response to ICNU DRs 012, 046, and 049
23 provided more recent information regarding the Company's utilization of net operating
24 loss carryforwards, which should be factored in the ultimate amounts considered by the
25 Commission and reflected in rates in this matter.

^{47/} 26 C.F.R. § 1.167(l)-1(a)(1).

1 **Q. HAS THE NET OPERATING LOSS CARRYFORWARD BALANCE BEEN**
2 **DECLINING?**

3 A. Yes. Relative to the balance of \$273.8 million, reflected in the Company's filing, the net
4 operating loss carryforward balance as of December 31, 2016 was just \$110.7 million.^{48/}
5 The Company utilized 59.6 % of the remaining balance over a three-month period, an
6 understanding the Company confirmed in response to ICNU DR 046.^{49/}

7 **Q. DOES THE COMPANY EXPECT THE BALANCE TO FURTHER DECLINE?**

8 A. In response to ICNU DR 049, Confidential Attachment A, the Company provided a
9 forecast of the tax-affected net operating loss carryforward balances, under various tax
10 reform scenarios.^{50/} That attachment demonstrated that absent tax reform, taxable
11 income in 2017 will be more than sufficient to utilize the entirety of the net operating loss
12 carryforward currently on the Company's books. Based on this information, the net
13 operating loss carryforward is appropriately eliminated from rates in its entirety as a pro
14 forma adjustment.

15 **Q. IS TAX REFORM APPROPRIATELY CONSIDERED WITH RESPECT TO THE**
16 **RATEMAKING IMPACTS OF NET OPERATING LOSS CARRYFORWARDS?**

17 A. No. If tax reform is approved, there are significantly greater revenue requirement
18 impacts that will need to be resolved, more than offsetting the impact of net operating
19 loss carryforwards rate base items. In fact, if tax reform is approved in the manner the
20 Company forecasts in response to ICNU DR 049, there need to be mechanisms in place

^{48/} Exh. No. BGM-5C at 6-8 (The Company's Resp. to ICNU DR 012, Redacted Attach. A).

^{49/} See id. at 19 (The Company's Resp. to ICNU DR 046).

^{50/} Id. at 24-25 (The Company's Resp. to ICNU DR 049, Redacted Attach. A).

1 to ensure that all of the benefits of that change are returned to customers, such as a
2 deferral.

3 **Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR**
4 **RECOMMENDATION?**

5 A. My recommendation results in an approximate \$7.6 million and \$1.3 million reduction to
6 revenue requirement for electric services and gas services, respectively.

7 **IV. PRODUCTION TAX CREDIT CARRYFORWARD AND TREASURY GRANT**
8 **AMORTIZATION**

9 **Q. HOW DOES THE COMPANY PROPOSE TO USE THESE REGULATORY**
10 **LIABILITIES?**

11 A. The Company proposes to use the funds due to customers with respect to production tax
12 credit carryforwards and treasury grants to offset Colstrip Units 1 and 2 decommissioning
13 and remediation expense.^{51/} The Company believes it is justified in this treatment based
14 on the statute RCW 80.84.020.

15 **Q. DO YOU AGREE WITH THE COMPANY PROPOSAL?**

16 A. No. In this case, the balances far exceed the expected decommissioning and remediation
17 costs. In fact, based on the sensitivity performed in Exhibit No. BGM-6, the regulatory
18 liability balances associated with production tax credits exceed the entirety of the end of
19 life costs through 2030, including the Company's unrecovered investment.

20 In addition, I believe it will create a number of problems by comingling the
21 regulatory liability accounts with the ordinary Colstrip Unit 1 and 2 plant accounts, as the
22 plant is transitions to end of life accounting, such as making it difficult to track the
23 ultimate amount of the regulatory liability funds returned to customers.

^{51/} See Exh. No. KJB-1T at 30:1-32:9.

1 **Q. WHAT DOES THE STATUTE SAY?**

2 A. The statute the Company cites simply confirms the Commission's ability to apply
3 regulatory liability accounts to offset remediation expenses, it does not require it.

4 **Q. WHAT AMOUNT OF FUNDS HAS THE COMPANY ACCRUED TO THE**
5 **REGULATORY LIABILITY PRODUCTION TAX CREDIT?**

6 A. According to ICNU DR 015, as of the end of the test period, the regulatory liability
7 balance associated with production tax credit carryforwards is approximately \$182.4
8 million.^{52/} According to ICNU DR 016, as of December 31, 2016, the regulatory liability
9 balance associated with production tax credits had grown to approximately \$291 million
10 due to customers.^{53/} The value presented in ICNU DR 016, however, may have been an
11 error, as the Company reported in ICNU DR 011 a year end balance due to customers of
12 \$197.2 million, which better corresponds to the amounts included in the test period.^{54/}

13 **Q. WHEN DOES THE COMPANY EXPECT TO BEGIN AMORTIZING THE**
14 **BALANCE TO CUSTOMER RATES?**

15 A. This was detailed in ICNU DR 049, Confidential Attachment A.^{55/} Absent any changes,
16 the Company's production tax credit carryforward balances will begin to be utilized on
17 its 2017 tax return, with an even greater amount utilized on the Company's 2018 tax
18 return. In 2017, the Company forecast production tax credit utilization of \$7.0 million
19 and in 2018, the Company forecast production tax credit utilization of \$52.0 million. The
20 revenue requirement impact of these utilization amounts is \$90.8 million, which would
21 otherwise have been provided as a benefit to ratepayers beginning in the rate period.

^{52/} Exh. No. BGM-5C at 14 (The Company's Resp. to ICNU DR 015).

^{53/} Id. at 16-18 (The Company's Resp. to ICNU DR 016, Redacted Attach. A).

^{54/} Id. at 2-4 (The Company's Resp. to ICNU DR 011, Redacted Attach. A).

^{55/} Id. at 22-25 (The Company's Resp. to ICNU DR 049, Conf. Attach. A).

1 Thus, instead of benefitting from the significant amortization of the regulatory balances
2 beginning in 2018, under the Company's proposal, customers may not receive a benefit
3 from production tax credits for many years. In fact, Mr. Roberts' testimony forecast
4 remediation expenditures to continue for an extended period of time, perhaps as far into
5 the future as 2051.^{56/} Thus, benefits of the balance won't be returned to ratepayers
6 through the reduction of remediation expenditures until 2050, or not at all.

7 **Q. DOES THE REGULATORY LIABILITY BALANCE FOR PRODUCTION TAX**
8 **CREDITS EXCEED THE EXPECTED REMEDIATION EXPENDITURES?**

9 A. Yes. The regulatory liability balance of \$197.2 million, detailed above, far exceeds the
10 expected remediation and decommissioning expenditures the Company forecasts. Mr.
11 Roberts' analysis showed only \$102.9 million of total remediation and decommissioning
12 costs through 2051, based on the Company's share of those costs.^{57/} In addition, since
13 some of the remediation expenditures won't be completed for many decades, the residual
14 regulatory liability balances would may not be resolved for over 30 years. That means
15 that the excess amounts of production tax credit liabilities might not be returned to
16 ratepayers until 2051. That is particularly unfair considering that the resources giving
17 rise to the regulatory liability are primarily being paid for by this generation of
18 ratepayers.

19 Finally, since the Company simply proposes to eliminate the net salvage
20 component, there would be no way of tracking the amount of the regulatory liability
21 which has been used to fund decommissioning expenses, which may lead to a situation

^{56/} Exh. No. RJR-1CT at 53:2-4.

^{57/} Exh. No. RJR-23 at 2.

1 down the road where the remaining balances due to customers simply disappear on the
2 Company's books.

3 **Q. WHAT DO YOU RECOMMEND?**

4 A. I recommend that the Commission begin to amortize the production tax credits
5 prospectively over the four and one-half year period ending July 2022, corresponding to
6 the remaining useful life of Colstrip. This amortization will serve substantially the same
7 purpose as the Company's proposal, albeit ensuring that all of the credits are returned to
8 ratepayers in a timely manner. Viewed in conjunction with my proposal related to
9 Colstrip closure costs, above, this treatment serves to offset the cost in the period in
10 which ratepayers are responsible for ongoing depreciation expenses, in addition to
11 amortization of the end of life regulatory asset.

12 **Q. WHAT IF THE COMPANY'S TAX LIABILITY ULTIMATELY DOES NOT**
13 **ALLOW FOR THE UTILIZATION OF THE CARRYFORWARDS?**

14 A. The production tax credit amounts have been on the Company's books for a long enough
15 period. In addition, the Company is not accruing any interest on the balances. Since
16 there is no carrying charge, the Company actually imputes a return on the balances in its
17 financial statements, as it would earn if the tax asset were reflected in rate base. As a
18 result, Company has little incentive to return the funds due to ratepayers. The balances,
19 however, have remained on the Company's books for too long, and at this point, the
20 Company should bear any remaining timing risk of being able to utilize production tax
21 credits on its tax return.

1 **Q. DOES THE COMPANY EXPECT IT WILL BE ABLE TO FULLY UTILIZE THE**
2 **PRODUCTION TAX CREDITS ON FUTURE RETURNS?**

3 A. Yes. According to ICNU DR 048, the Company has not recorded any valuation
4 allowance with respect to the production tax credit carryforward tax assets recorded on its
5 financial statements.^{58/} Accordingly, the Company has an expectation that it will, at
6 some point in the future, be able to fully utilize the existing production tax credit
7 carryforward. Thus, while there may be some uncertainty as to the timing, the Company
8 has no expectation that the credits will go unutilized.

9 **Q. HOW SHOULD TREASURY GRANT AMORTIZATION BE HANDLED?**

10 A. Compared to production tax credits, the impact of the treasury grants related to hydro
11 upgrades and the lower snake river facility is smaller. For that reason, I believe the
12 Commission should adhere to the long-term treatment that it has previously approved
13 with respect to the amortization of treasury grants.

14 **Q. PLEASE ELABORATE.**

15 A. The Commission has afforded PSE's production tax credits and treasury grants similar
16 regulatory treatment, allowing the monetized proceeds from each to be passed on to
17 ratepayers as rate credits under Schedule 95A.^{59/} In 2017, approximately \$52.7 million
18 dollars will be passed back to PSE's electric customers as a result of the operation of
19 Schedule 95A.^{60/} There is no reason to vary from this approach.

^{58/} Exh. BGM-5C at 20 (The Company's Resp. to ICNU DR 048).

^{59/} WUTC vs. Puget Sound Energy, Inc., Docket UE-120277, Order 02 at 14 (2012).

^{60/} See also In the Matter of Puget Sound Energy, Petitioner, Seeking Approval of Tariff Revisions to Schedule 95A and Requesting Exemption from the Provisions of WAC 480-100-198 Relating to Notice Verification and Assistance, Docket No. UE-161176, Order 01 (2016).

1 **Q. WHAT IS THE IMPACT OF YOUR PROPOSAL?**

2 A. Amortizing the remaining production balance over the 4.5 year period ending July 2022
3 will result in an annual benefit of approximately \$46.0 million in revenue requirement for
4 electric services. Similarly, reverting to the Commission approved revenue requirement
5 methodology for treasury grants results in an approximate \$4.2 million reduction to
6 revenue requirement for electric services.

7 **V. PENSION EXPENSES**

8 **Q. WHAT AMOUNT OF PENSION EXPENSE HAS THE COMPANY INCLUDED**
9 **IN REVENUE REQUIREMENT?**

10 A. The Company proposes to include pension expenses in revenue requirement based on the
11 level of contributions to pension expenses over the four year period ending September 30,
12 2016.^{61/} This analysis results in an annual pension cost of \$21.5 million, of which 54.7%
13 is allocated to expenses and the remaining 43.3% is allocated to capital.

14 **Q. HAS THE COMMISSION APPROVED THIS TREATMENT IN THE PAST?**

15 A. Yes. The Company has used average contributions during a four year period at least as
16 far back as Docket UE-920433 (cons.).^{62/} Notwithstanding, in Docket UE-090704
17 (cons.), the Commission issued Order 11, where it required the Company to use four
18 years of expense, rather than four years of contributions.^{63/} The Commission found that
19 the actual four year average pension expense ending December 31, 2008, provides a

^{61/} See the workpaper of Ms. Barnard titled "6.15E & 6.15G Pension Plan 17GRC.xlsx."

^{62/} WUTC vs. Puget Sound Power & Light Company, Dockets UE-921262 et al. (Cons.), Eleventh Supplemental Order at 64 (Sept. 23, 1993).

^{63/} WUTC vs. Puget Sound Energy, Inc., Dockets UE-090704/UG-090705 (Cons.), Order 11, ¶ 79 (Apr. 2, 2010).

1 reasonable measure of the amount of pension expense that should be allowed for
2 recovery in rates.^{64/}

3 It is not clear if the Company followed the Commission's requirement to use four
4 years of expenses in Docket UE-111048, the Company's 2012 GRC. It is clear in this
5 matter, however, that the Company did not use four years of expense, and instead
6 continues to use a methodology based on four years of contributions.

7 **Q. HAS THE COMMISSION BEEN MOVING AWAY FROM THE USE OF**
8 **HISTORICAL CONTRIBUTIONS TO ESTABLISH PENSION COSTS?**

9 A. Yes. For example, in Docket UE-140762, the Commission adopted the recommendation
10 of Public Counsel witness, Donna Ramas, regarding the use of actuarial pension costs for
11 establishing pension costs for ratemaking.^{65/}

12 **Q. DO YOU PROPOSE SIMILAR TREATMENT IN THIS MATTER?**

13 A. Yes. Use of the pension expenses, rather than historical contributions, will better spread
14 the cost of the pension plan over time into the periods in which the costs are actually
15 incurred. In contrast, contribution levels are based in part on judgment and have a
16 tendency to be lumpy.

17 **Q. WHAT AMOUNT OF PENSION EXPENSE DID THE COMPANY INCUR IN**
18 **THE HISTORICAL PERIOD?**

19 A. In the Company's results of operations, it includes \$16.6 million of pension expense for
20 the 12 months ending September 2016. Over calendar year 2016, the Company incurred
21 pension expense of \$14.5 million and pension income of \$15.5 million.^{66/}

^{64/} Id.

^{65/} WUTC vs. Pacific Power & Light Company, Docket UE-140762 et al., Order 08, ¶ 46 (Mar. 25, 2015).

^{66/} Puget Sound Energy Inc. 2016 10-K.

1 **Q. WHAT AMOUNT OF PENSION EXPENSE DOES THE COMPANY EXPECT IN**
2 **2017?**

3 A. Based on its 2016 Form 10-K for the year ending December 31, 2016, the Company
4 reported its actuarial pension expenses of \$12.7 million and pension income of \$14.0
5 million.^{67/} I propose that the Commission establish pension expense at this actuarial
6 level, rather than the amount included in the Company's filing, similar to its treatment of
7 pension expenses in Docket UE-140762.

8 **Q. IS THE COMPANY'S PENSION PROPERLY FUNDED?**

9 A. My understanding is that, similar to the pension plans of many utilities in the Northwest,
10 the Company's pension plan has been underfunded in recent history. The Company's
11 10-K, however, states that "[a]s of January 1, 2017, the plan's estimated funded ratio, as
12 calculated under guidelines from The Pension Protection Act of 2006 and considering
13 temporary interest rate relief measures approved by Congress, was more than 100%."
14 Thus, in contrast to recent history, the Company's pension funding level has improved.
15 This improved funding level is a reason that it is timely to transition to expense based
16 ratemaking for the pension plan of the Company.

17 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

18 A. The Company's 2017 pension expense was reported \$12.7 million in 2017, representing
19 an approximate reduction of \$8.8 million, relative to the \$21.5 million of pension
20 expenses included in the Company's filing. This reduction amount is allocated between
21 expense and capital using the 54.7% factor detailed above. These amounts were further
22 allocated between electric and gas services using the direct labor allocator of 67.4% and

^{67/} Id.

1 32.6% for the respective service lines. The revenue requirement impacts are
2 approximately \$3.4 million for electric services and \$1.6 million for gas services.

3 VI. PLANT HELD FOR FUTURE USE

4 **Q. WHAT AMOUNT OF PLANT HELD FOR FUTURE USE DOES THE**
5 **COMPANY PROPOSE TO INCLUDE IN RATE BASE?**

6 A. Based on the workpaper of Ms. Barnard titled “5.03 E&G RB - 5.04 E&G WC 17GRC,”
7 the Company included approximately \$49.3 million and \$1.4 million of plant held for
8 future use in rate base for electric and gas services, respectively. In response to ICNU
9 DR 063, Attach. A, the Company provided a list of approximately 73 properties which
10 the Company proposes to include in plant held for future use in this matter, along with a
11 description and other information related to each property that the Company proposes.^{68/}
12 In response to Public Counsel DR 297, the Company provided a list of properties held for
13 future use included in gas and common plant.^{69/}

14 **Q. WHAT STANDARD HAS THE COMMISSION HISTORICALLY FOLLOWED**
15 **WITH RESPECT TO PLANT HELD FOR FUTURE USE?**

16 A In 1993, the Commission issued a relevant determination in a rate case involving the
17 predecessor of Puget Sound Energy.^{70/} In that proceeding, the Commission adopted
18 several Staff criteria for determining when plant held for future use should be reflected in
19 rate base.^{71/} For example, the Commission established a criterion that plant held for

^{68/} Exh. No. BGM-5C at 26-32 (The Company’s Resp. to ICNU DR 063, Attach. A).

^{69/} Id. at 45-48 (The Company’s Resp. to Public Counsel DR 297, Attach. A).

^{70/} WUTC vs. Puget Sound Power & Light Company, Dockets UE-921262 et al. (Cons.), Eleventh Supplemental Order (Sept. 21, 1993).

^{71/} Id. at 89-91.

1 future use be removed “which have no specific dates on which they are expected to be
2 placed in service.”^{72/}

3 **Q. SHOULD THE COMMISSION CONTINUE THE PRACTICE OUTLINED IN ITS**
4 **1993 ORDER?**

5 A. While much about the 1993 standard may be relevant today, I recommend tightening the
6 standard somewhat. The Commission noted in that matter that “Puget does have a very
7 large balance in its Plant Held for Future Use account,”^{73/} and that large balance
8 continues to this day. Notwithstanding, unless there is a clear understanding of the
9 benefit that these perpetually large balances provide to ratepayers, it is not fair to
10 continue to include them in rate base as a component of rates.

11 To include property in a rate base valuation, it needs to be demonstrated to be
12 used and useful to ratepayers.^{74/} Properties held for future use clearly are not used to
13 provide service, nor do they qualify for the exception to the used and useful standard,
14 since the properties do not constitute construction work in progress. At most, the
15 properties are only arguably useful, in that they have the potential to provide future
16 benefits to ratepayers. If included in rate base on the basis of ratepayer benefits,
17 however, the benefits resulting from the ownership in the property should at least be
18 demonstrated to be sufficient to justify the carrying charge reflected on rate base.

^{72/} Id. at 89.

^{73/} Id. at 90.

^{74/} RCW 80.04.250

1 **Q. HAS THE COMPANY DEMONSTRATED THAT ITS OWNERSHIP OF THESE**
2 **PROPERTIES PROVIDE RATEPAYERS BENEFITS?**

3 A. No. In ICNU DR 065, the Company was requested to identify and quantify any ratepayer
4 benefits associated with each property held for future use.^{75/} The Company’s response
5 was “[p]lease refer to pages 89-91 of the Eleventh Supplemental Order in WUTC
6 Dockets UE-920433, UE-920499 and UE-921262, which provide the authority for Puget
7 Sound Energy (“PSE”) to include Plant Held for Future Use in rate base.”^{76/} Apparently,
8 the Company believed it was irrelevant whether the plant held for future use provides any
9 benefit to ratepayers. I disagree.

10 In ICNU DR 099, the Company was again requested to quantify any benefits
11 associated with the various properties held for future use.^{77/} In response, the Company
12 provided some additional narrative, but did not provide any quantitative analysis. The
13 narrative, however, provided little indication of the benefits associated with plant held for
14 future use, and in fact, just raises more questions about the reasonableness of including
15 plant held for future use in rate base.

16 **Q. ARE THERE ANY PARTICULAR PROPERTIES THAT ARE CONCERNING?**

17 A. Of the \$49.3 million electric plant held for future use, approximately \$22.2 million relates
18 to lower snake river wind development rights. The Company alleges that it will develop
19 this site within the next 20-years based upon renewable resource identified in its
20 Integrated Resource Plan. This property, however, raises a number of red flags.

^{75/} Exh. No. BGM-5C at 33 (The Company’s Resp. to ICNU DR 065).

^{76/} Id.

^{77/} Id. at 50-51 (The Company’s Resp. to ICNU DR 099).

1 First, it should not be assumed that a utility-owned resource would be chosen
2 from the results of a request for proposal process conducted to satisfy a need identified in
3 the Company's Integrated Resource Plan. The Company may certainly bid its property
4 into a request for proposal, but it is not appropriately viewed as a foregone conclusion
5 that the Company's property is the most cost effective way to comply with the renewable
6 portfolio standards requirements.

7 Second, requiring ratepayers to finance this development asset provides an unfair
8 advantage to the Company with respect to its procurement practices. Other developers
9 involved in a procurement process must acquire properties at their own risk, until the
10 properties are considered in a request for proposal, or some other process. In contrast to
11 other developers, the Company's ratemaking proposal would result in it actually earning
12 returns on its development rights, irrespective of whether its property is ultimately
13 selected in a request for proposal, or other, procurement process. Finally, these
14 properties represent distinct generation assets that have not achieved commercial
15 operations, nor commenced construction, and therefore, cannot be said to satisfy the used
16 and useful criteria.

17 Similarly, on the gas side, the majority of the amounts that the Company proposes
18 relate to land associated with the Tacoma liquefied natural gas facility, for which
19 ratepayers are not appropriately responsible.

20 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO PLANT HELD FOR**
21 **FUTURE USE?**

22 A. There have been no demonstrated benefits associated with the large plant held for future
23 use balances. According I recommend removing the entire amount of the respective

1 balances—approximately \$49.3 million, \$1.4 million and \$2.1 million for electric, gas,
2 and common plant held for future use, respectively. The impact of this recommendation
3 is an approximate \$5.0 million and \$0.4 million reduction to electric and gas revenue
4 requirement, respectively.

5 VII. GREENWOOD NATURAL GAS EXPLOSION

6 **Q. PLEASE PROVIDE SOME BACKGROUND ON THE GREENWOOD NATURAL**
7 **GAS EXPLOSION.**

8 A. The Greenwood natural gas explosion occurred on March 9, 2016 in the early morning.
9 The explosion caused property damage and injuries to first responders. The Commission
10 investigated the cause of the explosion in Docket PG-160924. In that matter, the
11 Company admitted to violating both state and federal pipeline safety regulations.^{78/}

12 **Q. DOES PSE'S REVENUE REQUIREMENT INCLUDE COSTS ASSOCIATED**
13 **WITH THE GREENWOOD NATURAL GAS EXPLOSION?**

14 A. Yes. According to WUTC Staff DR 261, the Company's unallocated results included at
15 least \$3.6 million of costs related to the Greenwood natural gas explosion.^{79/}
16 Commission penalties constitute approximately \$3.2 million of this amount.^{80/} While not
17 necessarily transparent from the Company's response to WUTC Staff DR 261, however,
18 it appears that the penalty amount has been recorded "below-the-line" and excluded from
19 revenue requirement in this matter. Notwithstanding, it appears that at least \$0.4 million
20 of legal and other operations costs have been included above-the-line in revenue
21 requirement.

^{78/} WUTC vs. Puget Sound Power & Light Company, Docket PG-160924, Settlement Agreement at ¶ 7 (Mar. 28, 2017).

^{79/} Exh. No. BGM-5C at 54 (Company Resp. to WUTC Staff DR 261)

^{80/} Id.

1 **Q. WHY IS IT SOMEWHAT AMBIGUOUS WHETHER THE PENALTY WAS**
2 **INCLUDED OR EXCLUDED?**

3 A. The Company recorded the penalty in FERC account 426, which I believe it has excluded
4 from results, not as a pro forma or restating adjustment, but through a “below the line”
5 adjustment made prior to its results of operations.

6 The concept of a below-the-line adjustment is somewhat troubling because, unlike
7 the pro forma and restating adjustments, the adjustments are not documented or
8 explained. In fact, it begs the question of what benefits items the Company might be
9 recording below-the-line. For instance, the Company’s income statement also includes
10 life insurance benefits of \$2.1 million in FERC account 426, and it’s somewhat
11 ambiguous whether the Company has taken the position that those benefits should be
12 retained by the shareholders.

13 In any case, the Greenwood natural gas explosion is significant enough that it
14 seems like it would have been more appropriately documented as a separate restating
15 adjustment, rather than a below-the-line adjustment. The fact that the Company appears
16 to have excluded some, but not all, of the Greenwood natural gas explosion costs is an
17 example of why it is preferable not to consider adjustments below-the-line, and instead,
18 document them as pro forma or restating adjustments.

19 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE GREENWOOD**
20 **NATURAL GAS EXPLOSION COSTS?**

21 A. Since the Company admitted to violating safety regulations, all expenditures related to
22 the explosion should be excluded from revenue requirement. The Commission would
23 appropriately consider not just expense items, but capital costs as well.

1 **Q. WHAT AMOUNTS SHOULD BE EXCLUDED?**

2 A. At least \$0.4 million of expenditures related to the explosion should be excluded from
3 results. Notwithstanding, the Company did not report any capital costs in response to
4 WUTC DR 261. Capital costs are also appropriately excluded, along with any additional
5 costs associated with the explosion identified during the course of this proceeding. Based
6 on the information I have reviewed, I recommend a reduction of \$0.4 million to the
7 Company's natural gas revenue requirement with respect to the Greenwood natural gas
8 explosion.

9 **VIII. ENVIRONMENTAL REMEDIATION**

10 **Q. HOW HAS THE COMPANY CALCULATED ENVIRONMENTAL**
11 **REMEDATION EXPENSES?**

12 A. According to the workpaper of Ms. Barnard, titled "6.19E & 6.19G Environmental
13 17GRC," the Company proposes to include approximately \$1.4 million and \$8.6 million
14 of deferred environmental remediation expenses for electric and gas services,
15 respectively.

16 **Q. HOW WERE THE DEFERRED AMOUNTS CALCULATED?**

17 A. These amounts represent accumulated environmental remediation costs incurred over the
18 sixteen-year period 2000 through 2016. The calculation also includes the benefit
19 associated with an accumulated amount of insurance proceeds received over the same
20 period. The Company then estimated an amount of future costs, which was used to
21 prorate the insurance proceeds included in the deferred balance.

1 **Q. DO YOU AGREE WITH THE WAY THAT THE COMPANY HAS**
2 **CALCULATED THESE AMOUNTS?**

3 A. No. First of all, it somewhat unclear why the Company is just now beginning to amortize
4 these balances which have accrued over the past 16 years. It would seem like the
5 Company should have been amortizing these balances for that entire time, so there are
6 some questions as to legitimacy of the deferral.

7 **Q. DO YOU AGREE WITH THE WAY THE COMPANY HAS ACCOUNTED FOR**
8 **FUTURE ENVIRONMENTAL COSTS?**

9 A. No. The Company's use of estimated future environmental costs to reduce insurance
10 proceeds is based on speculative assumptions, and for that reason, should not be used in
11 the formula used to set the deferred amount. For example, the Company reports both low
12 and high cost estimates for the future costs. For gas, this uncertainty represents
13 approximately \$26.9 million, representing a pretty significant *cone of uncertainty*. In
14 ICNU DR 055, the Company provided further detail regarding these future costs.^{81/}

15 **Q. HOW DO THE FUTURE COSTS IMPACT THE ENVIRONMENTAL**
16 **REMEDATION EXPENSES IN REVENUE REQUIREMENT?**

17 A. Based on the methodology the Company used, the effect of removing the future cost
18 assumption is that only a fraction of the insurance proceeds are being returned to
19 customers.

20 **Q. WHAT DO YOU PROPOSE?**

21 A. I recommend removing the future cost assumption in the calculation of deferred
22 environmental remediation expenditures. This will allow 100% of insurance proceeds to
23 be returned to ratepayers.

^{81/} Id. at 56-60 (The Company's Resp. to ICNU DR 055, Attach. A).

1 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

2 A. Allowing 100% of the historical insurance proceeds to be returned to customers results in
3 an approximate \$0.6 million and \$4.4 million reduction to revenue requirement for
4 electric services and gas services, respectively.

5 **IX. CLEAN AIR RULE MODELING**

6 **Q. WHAT IS THE CLEAN AIR RULE AND HOW HAS THE COMPANY**
7 **PROPOSED TO ACCOUNT FOR IT IN RATES?**

8 A. The Clean Air Rule is a regulation issued by the Washington State Department of
9 Ecology through WAC § 173-442. The rule establishes greenhouse gas emission
10 standards for emissions from a number of different in-state sources, including certain
11 Company-owned natural gas-fired generating facilities. The Clean Air Rule modeling is
12 described in the Direct testimony of Mr. Wetherbee.^{82/} Basically, the Company applied
13 an annual cap on the output from affected gas units. The total net operating impact of
14 the Clean Air Rule is approximately \$19.2 million, as detailed in the redacted version of
15 Exh. No. PKW-12C, although my recommendation does not yet incorporate the other
16 impacts of Mr. Wetherbee's supplemental filing.

17 **Q. WHAT WAS THE PURPOSE OF THE CLEAN AIR RULE?**

18 A. The purpose of the rule is to address environmental problems associated with greenhouse
19 gas emissions. According to the rulemaking, "emissions from human activity have risen
20 to unprecedented levels, increasing the average global temperature and the ocean's
21 acidity."^{83/} Thus, the goal of the regulation is to positively influence the level of carbon
22 emissions.

^{82/} Exh. No. PKW-1CT at 47:4-49:8.

^{83/} Washington Department of Ecology, Order AO # 15-10, CR-102 Proposed Rule Making

1 **Q. IS IT CERTAIN THAT THE RULE WILL REMAIN IN EFFECT DURING THE**
2 **RATE YEAR?**

3 A. In fact, I understand that the rule is currently being challenged through the state court
4 system by the Company, among other parties, a process which may take several years,
5 but implementation the rule could be suspended during any appeal process if the
6 challenges to the rule at the circuit court level are successful.^{84/}

7 **Q. DOES THE COMPANY ACCOUNT FOR THE TRADING SYSTEM FOR**
8 **EMISSION REDUCTION UNITS?**

9 A. No. The rule creates a class of tradable greenhouse gas emissions certificates, known as
10 emissions reduction units (“ERUs”). An emission reduction unit may be created by
11 either exceeding greenhouse gas reduction targets or through a greenhouse gas reduction
12 program. With respect to greenhouse gas reduction programs, there has been little
13 guidance as to what programs might result in the creation of an emission reduction unit.
14 There is even less certainty surrounding the future market conditions associated with
15 tradable emission reduction units.

16 Energy efficiency is a key example of an item that might ultimately be used to
17 offset compliance obligations under the Clean Air Rule. Allowing energy efficiency to
18 be used for compliance obligations makes a lot of sense, because it results in reducing the
19 regional demand for generation and resulting emissions. This is in contrast to the
20 Company’s modeling which actually will have the effect of increasing supply side
21 emissions. Nevertheless, the Company does not appear to have modeled the potential

^{84/} ICNU is also challenging the Clean Air Rule through a separate petition that was consolidated with the Company’s.

1 cost of using ERUs and only modeled the option of limiting the dispatch of its in-state
2 gas-fired resources.

3 Similarly, the additional costs customers are being asked to bear with respect to
4 the retirement of Colstrip Units 1 and 2, and the carbon reductions that result from that
5 decision, would not be appropriately disregarded when considering the actions that the
6 Company is undertaking for the furtherance of the policy objectives of reducing
7 greenhouse gas emissions as desired in the Clean Air Rule.

8 **Q. DOES THE COMPANY'S MODELING OF THE CLEAN AIR RULE FURTHER**
9 **THE PURPOSE OF POSITIVELY INFLUENCING CARBON EMISSIONS?**

10 A. No. Not only is the Company's compliance plan expensive, it is antithetical to the
11 objective of the Clean Air Rule. The Company's proposal to back down efficient natural
12 gas units will reshuffle the supply of generation in the western interconnection, requiring
13 less efficient resources to increase output in order to meet the same level of demand on
14 the system. Thus, while the Company's proposed strategy might reduce its own carbon
15 emissions in Washington, regional carbon emissions will increase as a result if the
16 Company follows its proposed implementation plan.^{85/}

17 As an aside, it is unlikely, in my opinion, that carbon emissions can be effectively
18 regulated on a supply-side basis for any local industry that participates in interregional or
19 global trade. Similar to electricity, applying discrete carbon costs to producers in the
20 Northwest does not impact the demand for the products that they manufacture. Thus, the
21 production lost in the Northwest due to the imposition of carbon costs is made up in other
22 regions, which may emit even greater greenhouse gas emissions than emitted in the

^{85/} See Exh. No. BGM-5C at 35-38 (Company Resp. to ICNU DR 105, Attach. B)

1 efficient production processes we have developed in the Northwest. Nevertheless, one
2 option potentially available to the Company that may reduce regional emissions is to use
3 ERUs to offset its in-state emissions. As noted above, whether this would be the least-
4 cost compliance option for the Company is unknown because the Company appears not
5 to have considered it.

6 **Q. WHAT DO YOU RECOMMEND?**

7 A. I recommend establishing power costs without the Clean Air Rule modeling the
8 Company proposes in this matter. In addition, the Commission needs to use its expertise
9 to help inform emission reduction programs for the Company that make sense, and avoid
10 outcomes that produce results that are the opposite of that desired by the rule by
11 increasing regional emissions. I recommend establishing power costs without the Clean
12 Air Rule modeling the Company proposes in this matter on the basis that the Company
13 has not demonstrated that it cannot offset its emissions with ERUs as an alternative to
14 capping the dispatch of in-state generation facilities.

15 **X. ARDMORE SUBSTATION**

16 **Q. PLEASE DESCRIBE THE ARDMORE SUBSTATION.**

17 A. The Ardmore Substation is a new substation the Company completed in 2012 and is
18 seeking to place into rates in this proceeding. The substation was built to increase
19 reliability to the area and accommodate growth in the region.^{86/} The substation connects
20 to the Company's 115 kV transmission lines in the area and has two transformers, with
21 space to add two more to accommodate anticipated future regional growth.^{87/}

^{86/} Exh No. BGM-7 at 1-2 (PSE Resp. to ICNU DR 024)

^{87/} Id.; Exh. No. BGM-8 at 28.

1 Construction of the substation allowed PSE to transfer the capacity of the nearby
2 Interlaken substation and combine it with Ardmore.^{88/} Interlaken was subsequently
3 decommissioned.^{89/} Ardmore also addressed reliability issues associated with radial
4 transmission lines to other area substations, including Kenilworth, Lake Hills, Evergreen,
5 Spirit Brook, Midlakes, College, and Phantom Lake.^{90/}

6 **Q. WHEN DID THE COMPANY BEGIN PLANNING FOR THE ARDMORE**
7 **SUBSTATION?**

8 A. The Company initially proposed the substation in 2006, with a targeted completion date
9 of 2009.^{91/} At that time, the substation was projected to cost \$11.2 million.^{92/} The
10 substation, however, met with a number of delays and its design was repeatedly revised
11 and expanded to meet new Company objectives.^{93/} By the time the existing design and
12 location of the substation were finally selected, it was projected to cost \$25.9 million.^{94/}

13 **Q. HOW MUCH DID THE COMPANY ULTIMATELY SPEND TO CONSTRUCT**
14 **THE ARDMORE SUBSTATION?**

15 A. The Company spent \$39.5 million, a cost overrun of over \$13.6 million from the final
16 estimate.^{95/} This is also over \$28 million more than the substation was initially projected
17 to cost when it was first conceived. These costs do not include the cost to decommission
18 the Interlaken Substation, which are presumably reflected in group depreciation rates.^{96/}

^{88/} Exh No. BGM-8 at 28.

^{89/} Exh. No. BGM-7 at 1-2 (PSE Resp. to ICNU DR 024)

^{90/} Exh. No. BGM-9 at 15-16.

^{91/} Exh. No. BGM-8 at 5.

^{92/} Id.

^{93/} Id. at 5-23.

^{94/} Id. at 19.

^{95/} Exh. No. BGM-7 at 1 (PSE Resp. to ICNU DR 024).

^{96/} Id. at 2.

1 **Q. WHAT WERE THE PRIMARY CAUSES OF THESE COST OVERRUNS?**

2 A. According to Company documents, the most significant drivers were that (1) substation
3 costs were “much higher than anticipated due to cost to construct civil improvements,”
4 and (2) distribution costs were also “much higher than anticipated due to congested urban
5 environment with deeper than anticipated trenching and in street routing due to not
6 obtaining real estate rights through private property.”^{97/} Substation costs were over \$6
7 million higher than budgeted, while distribution costs were nearly \$3 million higher than
8 budgeted.^{98/}

9 **Q. DID THE COMPANY JUSTIFY THESE COST OVERRUNS IN TESTIMONY?**

10 A. No. In contrast to the testimony supporting the \$24 million in additional costs for the
11 Snoqualmie Falls Project,^{99/} the Company did not provide testimony on the Ardmore
12 Substation in its testimony.

13 **Q. ARE THERE REASONS TO BELIEVE THE COST OVERRUNS FOR THE**
14 **ARDMORE SUBSTATION ARE EVIDENCE OF IMPRUDENCE?**

15 A. Yes. According to Company documents, the Company did not assume that distribution
16 unit costs would be more expensive when installed in an urban area.^{100/} This would seem
17 to be an obvious oversight on the part of the Company, given the far more complex
18 construction and engineering issues an urban area presents. Similarly, the Company
19 apparently procured much of the substation’s materials and made significant design
20 decisions before it had even selected the final site.^{101/} This makes little sense as the

^{97/} Exh. No. BGM-9 at 19.

^{98/} Id.

^{99/} Exh. No.__(RB-1T).

^{100/} Exh. No. BGM-10 at 7 (PSE Resp. to ICNU DR 091 Attach B)

^{101/} Id. at 8.

1 design of any structure, including a substation, is necessarily dependent upon where it is
2 located. The Company itself noted that this process decision was “risky.”^{102/} Finally,
3 there is evidence that the contractor PSE selected for the project was not competent and
4 the Company did not address this issue soon enough. The Company noted a “pattern ...
5 of constant errors” on the part of the contractor, and that “[m]ost projects don’t have
6 errors of this magnitude.”^{103/} Nevertheless, the Company did not appear to remedy this
7 problem in a timely manner.^{104/}

8 **Q. WHAT DO YOU RECOMMEND?**

9 A. Because the Company has failed to justify the ultimate cost for the Ardmore Substation,
10 and there appears to be clear evidence of imprudence leading to the cost overruns, I
11 recommend that the costs the Company incurred above its final budget, or \$13.6 million,
12 be disallowed from recovery from customers.

13 **Q. DO YOU HAVE ANY OTHER OBSERVATIONS WITH RESPECT TO THE**
14 **ARDMORE SUBSTATION?**

15 A. Yes. The substation’s costs appear to be misallocated to the various rate schedules that
16 benefit from this substation. In general, standard rate spread and rate design principles
17 dictate that the costs of Company plant should be allocated in proportion to the benefits
18 various customer classes receive from that plant. In this case, over 36% of the Ardmore
19 Substation’s costs are allocated to two customers on Schedule 40.^{105/} This is roughly
20 consistent with the percentage of costs of the Interlaken Substation that was allocated to

^{102/}

Id.

^{103/}

Id. at 9.

^{104/}

Id.

^{105/}

Exh. No. BGM-11 at 1-2 (PSE Resp. to ICNU DR 024, First Supp. Resp.).

1 Schedule 40 customers.^{106/} However, Ardmore was designed not solely to replace
2 Interlaken, but to provide additional reliability benefits to the area. Consequently, it does
3 not appear that customers who are being served from other substations in the area that are
4 incurring reliability benefits from Ardmore are being assigned a fair share of the costs.
5 The Lake Hills Substation, for instance, serves primarily residential and small
6 commercial customers, and does not serve Schedule 40 customers at all.^{107/} Similarly, of
7 the Spiritbrook, Midlakes, College, and Phantom Lake substations, only Spiritbrook
8 serves any Schedule 40 customer.^{108/} Approximately 25% of this substation's costs are
9 allocated to one Schedule 40 customer.^{109/} The vast majority of customers served by
10 these substations are also residential and small commercial customers.^{110/} Finally, while
11 nearly 50% of the Kenilworth Substation's costs are allocated to a Schedule 40
12 customer,^{111/} the reliability benefits this substation receives from the new Ardmore
13 Substation inure to customers located south of the Kenilworth Substation.^{112/} The
14 identified Schedule 40 customer is located north of the Kenilworth Substation.
15 Therefore, the incremental reliability benefits received by the Kenilworth Substation are
16 irrelevant to Schedule 40.

^{106/} Exh. No. BGM-11 at 3-4 (PSE Resp. to ICNU DR 025).

^{107/} Id. at 5 (PSE Resp. to ICNU DR 085).

^{108/} Id. at 7 (PSE Resp. to ICNU DR 087).

^{109/} Id.

^{110/} Id.

^{111/} Id. at 6 (PSE Resp. to ICNU DR 086).

^{112/} Exh. No. BGM-8 at 27.

1 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE ALLOCATION OF**
2 **PRUDENTLY INCURRED COSTS FROM THE ARDMORE SUBSTATION?**

3 A. I recommend that the Company revise its allocation percentages in rebuttal testimony to
4 fully account for the reliability benefits customers served from other regional substations
5 receive as a consequence of the Ardmere Substation. In no event should the Schedule 40
6 customers that were allocated the costs of the Interlaken Substation receive an allocation
7 percentage of the costs of the Ardmere Substation that equal or exceed their allocation
8 percentages from the Interlaken Substation.

9 **Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?**

10 A. Yes.