EXHIBIT NO. ___ (EDH-5)
DOCKETS UE-170033/UG-170034
2017 PSE GENERAL RATE CASE
WITNESS: EZRA D. HAUSMAN, PH.D.

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-170033** **Docket UG-170034**

EXHIBIT EDH-5 TO THE

RESPONSE TESTIMONY OF

EZRA D. HAUSMAN, PH.D.

ON BEHALF OF SIERRA

CLUB

June 30, 2017

BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DOCKET NOs. UE-072300 and UG-072301

DIRECT TESTIMONY OF CHARLES W. KING (CWK-1T)

ON BEHALF OF

PUBLIC COUNSEL

MAY 30, 2008

DIRECT TESTIMONY OF CHARLES W. KING (CWK-1T)
DOCKET NOs. UE-072300 AND UG-072301

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Exhibit No.___ (CWK-9)	National Study of Other Production Unit Lives—Combustion Turbine Service Lives

I. INTRODUCTION / SUMMARY

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

A: My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. (Snavely King). My business address is 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q: Please describe Snavely King.

A: Snavely King, formerly Snavely, King, & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs, and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers, and cost analysts. Most of its work involves the development, preparation, and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 38-year history, members of the firm have participated in over a thousand proceedings before almost all of the state commissions and all federal commissions that regulate utilities or transportation industries.

Q: Have you prepared a summary of your qualifications and experience?

A: Yes. Exhibit No. ___ (CWK-2) is a summary of my qualifications and experience.

Q: Have you previously submitted testimony in regulatory proceedings?

A: Yes. Exhibit No. ___ (CWK-3) is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q: For whom are you appearing in this proceeding?

A: I am appearing on behalf of the Public Counsel Section of the Office of the Attorney General (Public Counsel).

Q: What is the objective of your testimony?

A: The objective of my testimony is to recommend depreciation rates for the electric and gas plant of the Puget Sound Energy Company (PSE or the Company). In the process, I will review and critique the depreciation study submitted by C. Richard Clarke on behalf of PSE.

Q: Please describe the process you used in preparing this testimony.

A: I began by reviewing the depreciation study submitted by Mr. Clarke. Based on that review, I prepared a number of data requests and carefully read the Company's responses. Independently, I evaluated the approach used by Mr. Clarke to the treatment of production plant lives and salvage and retirement costs, and I developed the alternatives that I shall discuss in my testimony. I then prepared the schedules found in my exhibits. The exhibits were prepared and the calculations performed either by me or under my direction.

II. SUMMARY OF RECOMMENDATIONS

Q: What depreciation rates do you recommend?

A: My recommended electric and gas plant depreciation rates are set forth in Schedules 1 of Exhibit No. ___ (CWK-4) and ___ (CWK-5), respectively. Schedules 1 of those exhibits also provide an account-by-account comparison of my recommended accruals with the existing accruals and those proposed by the Company. The accruals are all based on plant in service as of December 31, 2006. A summary comparison of my recommended rates accruals with the existing and Company proposed accruals are as follows:

Comparison of Accruals on 12/31/06 Plant

	Present	PSE Proposed	PC Recommended
Electric Plant			
Steam Production	$ 22,870,109	$ 26,011,990	$ 12,400,711
Hydro Production	11,348,270	4,774,697	3,133,568
Other Production	24,950,161	26,500,160	23,626,912
Transmission	7,796,779	6,803,170	5,847,870
Distribution	76,995,670	79,589,144	70,988,011
General	6,788,743	11,774,595	11,676,487
Total Electric	**$ 150,749,732**	**$ 155,453,756**	**$ 127,673,559**
Gas Plant			
Production	$ 334,834	$ 61,946	$ 46,164
Storage	766,758	460,795	393,050
LNG	432,970	400,147	382,346
Transmission	1,097,674	-	-
Distribution	64,942,654	72,845,223	53,366,786
General	2,518,382	10,239,164	5,402,942
Total Gas	**$ 70,093,272**	**$ 84,007,275**	**$ 59,591,289**

Q: How do your recommended depreciation rates differ from those proposed by Mr. Clarke?

A: My recommended depreciation rates differ from those proposed by Mr. Clarke in the following respects:

- I increase the life spans for the Colstrip units to 60 years.
- I increase life spans of the "other production" gas turbines to 45 years.

- I increase the average service life of account 365 – Overhead Conductors and Devices – from 40 to 45 years.
- I set removal cost accruals based on either the present value of the future costs or the net removal cost experience of the last five years, whichever is higher.

III. DEPRECIATION—GENERAL

Q: What is depreciation?

A: In 1958, the National Association of Railroad and Utility Commissioners sanctioned the following definition of depreciation:

> "Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[1]

The second commonly cited definition of depreciation is that of the American Institute of Certified Public Accountants:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[2]

[1] *Uniform System of Accounts for Class A and Class B Electric Utilities*, 1958, rev. 1962.
[2] American Institute of Certified Public Accountants, *Accounting Research and Terminology Bulletin #1*.

If depreciation can be defined in a single sentence, I would say that it is the process of recovering the initial investment in tangible capital assets, adjusted for net salvage, in a systematic fashion over the useful service life of the plant, recognizing that a utility plant is typically a group of investments.

Q: Does calculation of depreciation involve the exercise of judgment?

A: Yes. Depreciation calculations are similar in this sense to setting the required rate of return to equity investors. Both are developed from analyses that, while based on quantitative values, require considerable application of judgment. In the case of rate of return, that judgment pertains to the earnings expectations of investors as indicated by the stock market and corporate financial data. In the case of depreciation, the judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements.

Q: How does this judgmental characteristic of depreciation influence the Commission's approach to the subject?

A: The Commission must recognize that the development of depreciation rates is not a refined science subject to mathematical precision. Because depreciation analysts use judgment in their estimation of depreciation, the Commission must necessarily exercise its own judgment in assessing the rationale and data that underlie alternative depreciation rates. In this proceeding, the Commission must choose among depreciation rates that yield widely differing annual depreciation accruals.

Q: What are the basic parameters required to develop a depreciation rate?

A: At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the plant. The reciprocal of that number can be used as the depreciation rate.

However, because most utility depreciation is applied to accounts that are multiple units of plant, it is usually necessary to estimate the dispersion of retirements around an average service life. In the gas and electric utility industries, this dispersion is usually described in terms of "Iowa Curves," so named because they were developed at Iowa State University. These curves describe how closely the retirements are grouped around the average service life and whether they tend to occur more rapidly before, after, or coincident with the average service life.

Another parameter that is typically included in the calculation of a depreciation rate is net salvage. Net salvage is the difference between the positive scrap value of the asset's material and the cost of dismantling and removing the asset when it is retired. As traditionally applied, it is expressed as a ratio to the cost of the asset and included as a subtraction (when salvage value exceeds removal cost) or an addition (when removal cost exceeds salvage) to the amount to be recovered. With a few exceptions (e.g. vehicles, work equipment) most gas utility plant has a higher removal cost than its salvage value, so that recognition of net salvage adds to the amount to be recovered.

Finally, virtually all major utilities, including PSE, employ what is known as "remaining life depreciation." This procedure computes the depreciation rate by dividing the unrecovered net investment, adjusted for net salvage, by the estimated remaining years of the asset (or group of assets). It effectively ensures that any past under- or over-accruals of depreciation are recovered during the remaining life of the asset.

Q: Please illustrate how the parameters you have just described are used to develop depreciation rates?

A: Beginning with the simplest example, assume a single asset with a 20 year life. Its depreciation rate is the reciprocal of 20:

$$1/20 = 5\%$$

Now, let us assume that the asset is expected to have salvage value equivalent to 5 percent of its investment value. The depreciation rate declines:

$$\frac{1 - .05}{20} = \frac{.95}{20} = 4.75\%$$

Assume next that the cost of removing this asset amounts to 15 percent of its value. The depreciation rate increases:

$$\frac{1 - .05 + .15}{20} = \frac{1.10}{20} = 5.55\%$$

This is called a "whole life" rate because it is based on the whole life of 20 years. To develop the remaining life rate, we must identify some additional items of data: the original investment, the depreciation reserve (the amount of depreciation that has already been recovered), and the remaining life of the asset.

In this illustration, let us assume that the asset originally cost $1 million and that past depreciation charges have recovered $400,000. This means that we have yet to recover $600,000 in original cost, plus a negative net salvage (i.e. net cost of removal) amounting to 10 percent of the original cost, or $100,000. The total amount yet to be recovered is thus $700,000. Let us further assume that the asset is 10 years old, leaving 10 years of remaining life. In remaining life depreciation, the unrecovered amount is divided by the remaining life years:

$$\frac{\$700,000}{10 \text{ years}} = \$70,000 \text{ required annual accrual}$$

The depreciation rate is then calculated by dividing the annual amount to be recovered by the gross investment, in this case:

$$\frac{\$70,000}{\$1,000,000} = 7.0\%$$

The foregoing illustrates the traditional formulation of depreciation rates. As I shall discuss later in this testimony, I am recommending a modification that independently derives an annual allowance for the present value of net removal costs. Assume that this calculation yields an annual allowance of $5,000. In that case, the depreciation rate would be calculated as:

$$\frac{\$70,000 + \$5,000}{\$1,000,000} = 7.5\%$$

IV. COLSTRIP LIFE SPANS

Q: Have you identified depreciation issues with Colstrip plant in this case?

A: Yes. The Colstrip life spans, proposed by PSE, are unreasonably short because they are inconsistent with: (1) the Company's own Integrated Resource Plan, (2) the life spans approved for PacifiCorp, co-owners of Colstrip Unit 4, for the same plant, and (3) the service lives of steam plants nationwide.

Q: What do you mean by "life spans?"

A: The transmission, distribution and general plant accounts, both gas and electric, are known as "mass property" accounts because they consist of many individual items of plant that are continually being added and retired. As a result, there is no fixed terminal retirement date for the plant in these accounts. The forecast retirements range over virtually all the years in the foreseeable future.

That is not the case with production plants. They experience retirements and additions of piece parts during their service lives, but most of the plant is retired when the generating unit is finally taken out of service. Much of this "terminal retirement" plant is in service from the date the plant first starts up to the date it finishes generating electricity. That time between these two dates is the life span of the production plant.

Q: How does Mr. Clarke calculate depreciation for production plant?

A: In computing his depreciation rates for production plant, Mr. Clarke calculates the weighted average of the estimated remaining life of the terminal retirement plant and the remaining life of the plant that will retire in the interim prior to terminal retirement.

Q: How did the company estimate the life spans of its Colstrip steam production plants?

A: It is my understanding that these plant lives are based on the expiration of the contracts for coal deliveries to these plants.

Q: What life spans does the company recommend for its Colstrip plants?

A: The life spans now recommended by the Company are presented in Schedule 2 of Exhibit No. ___ (CWK-4). They range from 40 to 44 years.

Q: Why did the Company use the coal contracts as the basis for the Colstrip life spans?

A: In a conference call with the Company's personnel, I was told that the mine mouth coal at the Colstrip location will exhaust as these contracts expire.

Q: Have you since confirmed this information?

A: No. I inquired as to the exhaustion of the coal used by the Colstrip plant. The response is attached as Exhibit No. ___ (CWK-6). In PSE's response to Public Counsel Data Request No. 642, PSE states that there is no impending exhaustion of coal from the Rosebud Mine and that the reserves are sufficient to support operations through the end of 2019 *and beyond.*

Q: You have identified three reasons why you believe the Colstrip life spans are too short, the first of which is that they are inconsistent with the Company's own Integrated Resource Plan. What is the basis for this contention?

A: The basis for this contention is PSE's response to Public Counsel Data Request No. 646, which I have attached as Exhibit No. ___ (CWK-7). On page 38 of Mr.

Clarke's Revised Exhibit No. ___ (CRC-3), he lists the retirement dates of the four Colstrip units. According to Mr. Clarke, Units 1 and 2 are to be retired in 2019, Unit 3 is to be retired in 2024, and Unit 4 is to be retired in 2025. All of these retirements are within a 20-year horizon of 2007, the year the latest Integrated Resource Plan (IRP) was filed. Yet, according to Exhibit No. ___ (CWK-7), the 2007 IRP includes all four Colstrip units in PSE's resources throughout the 20-year planning horizon.

Q: The second reason you cited for stating that the life spans of the Colstrip units are too short is that they are inconsistent with the life span of the very same plant that has been approved for PacifiCorp, a co-owner of Colstrip Unit 4. What is the basis for this contention?

A: In Docket No. UE-071795[3], the Commission approved a multi-state settlement of the depreciation rates of PacifiCorp. That settlement included a 60-year life for the Colstrip plant.

Q: Your third reason for stating that the Company's life spans for the Colstrip units is that they are inconsistent with the lives of steam plants nationwide. What is the basis for this contention?

A: The basis for this contention is an actuarial study that my firm has conducted of all steam plant retirements since 1900. The study, described in Exhibit No. ___ (CWK-8), is based on the installation and retirement dates of these steam production units. The study reveals that the average life span of these plants was 59 years. The source of the data for this study is the Energy Information Service of the U.S. Department of Energy.

Q: What life span do you recommend for the Colstrip plants.

A: I recommend a life span of 60 years for the Colstrip units. The Company-proposed and my recommended retirement dates are presented in Schedule 2 of Exhibit No. ___ (CWK-4).

Q: Have you calculated depreciation rates that reflect a 60-year life for the Colstrip units?

A: Yes. The remaining lives in Column D of Schedule 1 of Exhibit No. ___ (CWK-4) are a composite of the remaining portion of each unit's 60-year life span and the remaining lives of the units of plant that are forecast to retire in the interim between now and the terminal retirement dates. In computing the remaining lives for these interim retirements, I have accepted the life and survivor curve parameters that are shown in Column 2 of Table 1 of Mr. Clarke's Revised Exhibit No.___ (CRC-3).

V. OTHER PRODUCTION PLANT LIVES

Q: What is meant by "other production?"

A: The term "other production" refers to the combustion turbine units that PSE uses to meet peak load conditions. There are six of these plants, and they are listed at the bottom of Schedule 2 of Exhibit No.___ (CWK-4). The term also applies to the two

[3] *In the Matter of the Petition of PacifiCorp, d/b/a Pacific Power, For An Accounting Order Authorizing a Revision to Depreciation Rates*, Docket No. UE-071795, Order No. 1, (April 10, 2008).

wind farms the Company has recently installed. Since I am not challenging the life parameters of the wind farms, I have not listed them on Schedule 2.

Q: What life spans does the company assume for these plants?

A: Schedule 2 of Exhibit No. ___ (CWK-4) also shows the installation year, the Company's forecast retirement year, and the assumed life spans of each of the plants. These numbers are abstracted from the table on page 38 of Mr. Clarke's Revised Exhibit No.___ (CRC-3).

Q: What is your assessment of the company's life span estimates?

A: The life spans of all the units other than Crystal Mountain are between 29 and 35 years. These estimates are unreasonably short. A far more appropriate estimate of the life span of a combustion turbine is 45 years.

Q: What is the basis for your assertion that 45 years is a more appropriate life span for combustion turbines?

A: The basis of this statement can be found in Exhibit No. ___ (CWK-9), which is my firm's study of combustion turbine service lives. That study, which covered all retirements of combustion turbines since 1899, indicates that these plants have survived on average 46.5 years and that this average has increased in recent years to 56.5 years.

Q: Have you calculated depreciation rates reflective of your 45-year life span estimate?

A: Yes. The remaining lives in Column D of Schedule 1 of Exhibit No. ___ (CWK-4) opposite the respective "other production" plant accounts, reflect my estimate of

45-year life spans. Like the steam plant remaining lives, these lives are a composite of the remaining life span of components that are forecast to survive to the plants' retirement and the interim retirements that will occur before that time. Again, I have accepted Mr. Clarke's life and survivor curve parameters for the interim retirements.

VI. ACCOUNT 365 – OVERHEAD CONDUCTORS & DEVICES

Q: What life and survivor curve does PSE propose to use for Account 365 – Overhead Conductors and Devices?

A: The Company is proposing a 40 year average service life with an R1 survivor curve.

Q: Do you agree with this life estimate?

A: No, I do not. While the Company's historical life studies justify a 40 year life, these are retrospective analyses that cannot anticipate future developments. In this case, the Company is proposing a considerable increase in its tree trimming expenditures. If the tree trimming program is enhanced, the probable effect will be less retirements from the Overhead Conductors account, leading to a longer average service life. This will continue the trend noted by Mr. Clarke in his write-up on Account 265 in the "Account by Account Summary" of his report.

Q: What service life to you recommend?

A: I cannot predict the precise effect of the enhanced tree trimming program, so I am proposing a modest 5-year increase in the average service life of plant in this account. The result is an average service life of 45 years.

VII. REMOVAL COSTS

Q: Does PSE incur removal costs?

A: Yes. PSE expects to incur removal costs for all of its steam and hydro production plants and most of its transmission and distribution plant accounts other than easements and structures. It also forecasts removal costs for the common plant structures account.

Q: How does PSE's depreciation witness, Mr. Clarke, treat removal costs?

A: For each of the affected plant accounts, Mr. Clarke adds his forecast removal costs, net of positive salvage, to the total amount of money to be recovered in depreciation rates. In this manner, he produces depreciation rates that recover both the original investment and the expected net cost to remove the plant represented by that investment.

Q: How does Mr. Clarke forecast his removal costs?

A: Mr. Clarke uses two procedures depending upon the type of removal costs, one for "mass property" accounts, which include all transmission and distribution accounts, the other for "life span" accounts, which include all of the production plant accounts.

Mr. Clarke does not describe his procedure for deriving removal costs for the mass property accounts, but it appears that he has employed what I call the Traditional Inflated Future Cost Approach that is used by virtually all utility-sponsored depreciation analysts. It begins with an examination of the history of retirements, removal costs and salvage proceeds. Mr. Clarke then subtracts each year's salvage receipts from that year's removal costs to derive an annual amount of "net salvage." Except for the transportation and power-operated equipment general plant accounts, the removal costs are always much more than the salvage proceeds, so the result is "negative net salvage." These amounts would better be expressed as "positive net removal costs," or just "removal costs." I shall use this term in the remainder of my testimony.

Mr. Clarke then compares the annual net removal costs to the annual amount of plant retired to derive a "net salvage ratio." The numerator is net salvage (net removal costs) and the denominator is retired plant. Because of the very great year-to-year variability of these ratios, he averages them for varying periods and selects what he deems a representative relationship of net removal costs to retirements. That relationship is then applied to the total value of plant in the account to derive the amount of net removal costs that must be recovered in depreciation rates.

Mr. Clarke does not use historical data for the "life span" production plants accounts. In these cases, it is necessary to estimate the costs to dismantle plants at the end of their service lives. While there have been no decommissioning studies, Mr. Clarke proposes to allow an amount in the net salvage rate for final dismantling until site-specific studies are performed. For this reason, he retains the existing removal cost ratios, as follows:

Acct. 311	Steam Plant Structures & Improvements	-5%
Acct. 312	Boiler Plant Equipment	-10%
Acct. 314	Steam Turbo Generator Equipment	-10%
Acct. 331	Hydro Structures & Improvements	-25%
Acct. 332	Reservoirs, Dams and Waterways	-25%

Q: How large are the removal cost ratios recommended by Mr. Clarke?

A: They are very large, at least for gas plant. Mr. Clarke's removal cost ratios are presented in Column 3 of Tables 1 and 2 of his depreciation study. The net removal cost ratios proposed by Mr. Clarke range as high as 75 percent for Account 380 – Gas Services. A 75 percent removal cost ratio means that for every dollar of depreciation recovered, another $0.75 is accrued against future removal costs.

Q: Can you quantify the annual removal cost accrual that Mr. Clarke proposes be charged to ratepayers for PSE's electric and gas distribution plant in this state?

A: Yes. Schedule 3 in Exhibit No. ___ (CWK-4) shows the accruals that Mr. Clarke proposes for electric transmission and distribution plant based on December 31, 2006, plant in service. For the electric plant, the annual removal cost accruals come to $6,185,797. Schedule 2 in Exhibit No. ___ (CWK-5) shows that the Company's proposed removal cost accruals for gas distribution plant amount to $15,989,716. These are the annual amounts that ratepayers would pay for removal costs each year based on year-end 2006 plant.

Q: How large are the actual removal costs that PSE has experienced?

A: The actual annual removal cost expenditures, net of salvage, for the years 2002 through 2006 are shown in the same schedules. For electric plant, actual removal cost expenditures for transmission and distribution plant came to $7,254,333. The average annual removal cost expenditure for gas distribution plant was $3,659,559 for all gas distribution plant.

Q: How do Mr. Clarke's proposed removal cost accruals compare with the actual removal cost experience?

A: The final columns of both schedule 3 in Exhibit No. ___ (CWK-4) and Schedule 2 in Exhibit No. ___ (CWK-5) show the difference between Mr. Clarke's proposed removal cost accruals and the average removal cost expenditures. For electric plant, the average removal cost expenditures exceed Mr. Clarke's proposed accruals by $1,068,536. For gas plant, Mr. Clarke's accruals exceed actual average expenditures by $12,330,157—over three times actual removal expenditures.

Q: How does Mr. Clarke derive such large removal cost accruals for gas plant when the actual experienced removal costs are so much less?

A: As discussed earlier, Mr. Clarke develops his removal cost allowances by comparing the original cost of retirements during recent years with the experienced costs of removal during those same years. The ratio of the removal costs to plant retirements becomes the removal cost ratio. As Mr. Clarke's report indicates, this ratio can be as high as 75 percent. These ratios are used to develop annual removal cost rates. When those rates are applied to all plant in service as of the December 31, 2006, the result is the annual accruals shown in Schedule 2 of Exhibit No. ___ (CWK-5).

The reason for these very high removal cost ratios is that Mr. Clarke is comparing dollars of very different values. The numerator of the removal cost ratio is recently incurred removal costs covering the years since about 2001. The denominator is the original cost of the plant retired. Those costs can be quite old. The average service life of a section of gas main is 50 years. If a 50 year-old gas main is retired in 2006, its original cost is expressed in 1966 dollars. According to Handy-Whitman, the construction cost index in 1966 for plastic gas mains was 76. By 2006, that index had increased to 434, or 5.7 times.[4]

With many low-valued dollars in the numerator and a few high-valued dollars in the denominator, the removal cost ratio is very high. As noted, these high ratios result in proposed removal cost accruals well over three times the actual removal cost expenditures. This is why I refer to Mr. Clarke's procedure as the Traditional Inflated Future Cost Approach, or TIFCA.

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[4] *Handy-Whitman Bulletin No. 165*, p. G-6-6 and G-6-8, Whitman Requardt & Associates, LLP, Baltimore, MD.

Q: What is the rationale behind TIFCA?

A: The rationale underlying TIFCA is set forth in *Public Utility Depreciation Practices*, published by the National Association of Regulatory Utility Commissioners[5]:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of its retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning are the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. <u>The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.</u> (emphasis supplied.)

The TIFCA procedure purports to forecast the future cost of removal associated with plant currently in service, and it charges that cost to the ratepayers that use that plant.

Q: Is this rationale valid?

A: The rationale would be valid if the TIFCA procedure recognized the present value of future costs. It does not.

Q: Why do you say that TIFCA fails to recognize the present value of future costs?

A: The TIFCA procedure charges ratepayers now for the nominal dollar cost of removing plant at the time of its retirement. Under Mr. Clarke's proposal, when

[5] National Association of Regulatory Utility Commissioners (NARUC), *Public Utility Depreciation Practices*, (August 1996), p. 157.

PSE installs a gas service in 2008, it would add a removal cost allowance of $0.75 to each dollar of construction cost recovered. Yet that $0.75 will not be spent, on average, for another 40 years, or until the year 2048. A dollar spent in 2048 is worth far less than a dollar collected in 2008. Not only will inflation erode the value of the 2048 dollar, but the holder of the dollar has the benefit of its earning (or spending) value in the intervening 40 years.

The TIFCA procedure simply ignores this relationship between present and future dollars. It assumes that a dollar collected now has exactly the same value as a dollar spent 40 years from now. Mr. Clarke would have PSE collect these 2048 dollars from ratepayers starting next year.

Q: **Your discussion has focused on removal costs for mass property transmission and distribution accounts. Does PSE fail to recognize that the present value of future costs applies to the production plant removal costs as well?**

A: Yes. The terminal dismantlement costs are estimated differently, but the same issue applies. Terminal dismantlement costs of steam and hydro production plant are estimated in 2006 dollars, not future dollars, as are mass property removal costs. Yet, just as with distribution plant removal costs, the terminal dismantlement costs will not be incurred for years to come. I am forecasting that the Colstrip plants will be retired between 2035 and 2045. It is not appropriate to collect undiscounted dollars in 2008 for a cost that will not be incurred until 2035.

Q: Doesn't the fact that removal cost accruals are included in the depreciation reserve that is subtracted from rate base adequately recognize the time value of those accruals?

A: No, it does not, for two reasons. First, the TIFCA front loads the accrual of future removal costs, and second, because the time value of money is much higher for ratepayers, particularly residential ratepayers, than it is for PSE.

Q: Why do you say that TIFCA front-loads the accrual of future removal costs?

A: If all of the vintages of plant (i.e. plant added each year) had the same dollar value and the same service life, then the subtraction of removal cost accruals from rate base would adequately account for the time value of money to ratepayers. But the reality is that, for almost all accounts, the dollar value of the vintages (new plant added each year) increases. That occurs because PSE's system is growing, and even if it were not, the continuous process of inflation would mean that just to replace the same plant as it is being retired, more dollars must be added each year.

As a result, in every account there are always more dollars of new plant than dollars of old plant. To illustrate, the average service life of the Gas Services Account No. 380 is 40 years. The remaining life of this plant is 28.8 years, which means that the average age of the dollars in this account is on the order of 11 years, or only about a third of the average service life.

The TIFCA procedure accrues removal costs for each vintage in even nominal dollar amounts each year, seemingly a straight-line recovery of those costs. But in "real" dollars, that is, dollars of equal value in terms of both inflation and time value, it is very much front-loaded; it recovers much more in the early years of a vintage's life than in the later years. Because all of the accounts have more money in newer than older vintages, the Company is always ahead, and ratepayers are always behind under TIFCA – even acknowledging the rate base subtraction – than if the accruals were expressed in dollars of equal time value.

Q: Why do you say that the time value of money is greater for ratepayers than for PSE?

A: If the time value of money to PSE is the same as it is to ratepayers, then ratepayers should be indifferent as to whether they pay more dollars now and receive the benefit of a rate base deduction, or whether they defer the rate base deduction and pay later.

But the time value of money is not the same. The time value of money to PSE is the interest rate that PSE pays for short-term debt. That rate varies month to month depending on the capital markets, but for most electric utilities, it is in the range of five to six percent.

The time value of money to PSE's ratepayers depends on the category of ratepayers. For some large industrial and commercial customers, the time value of money is likely to be about the same as that for PSE – the short-term borrowing rate. Those customers will be indifferent to whether removal costs are accrued sooner or later.

Smaller commercial customers probably have a higher short-term capital costs than PSE. "Mom and Pop" businesses usually pay a premium over the banks' prime rate owing to their lower credit ratings. Some marginal businesses may not have access to bank credit at all, in which case the time value of their money is measured by the late charges and penalties assessed by their creditors.

Of the three major categories of customers, residential customers have the highest time value of money. To begin with, only residential ratepayers have to pay their electric bills with after-tax dollars. If the marginal tax rate for a middle-class ratepayer is 35 percent, then the ratepayer must earn $1.54 (1/(1-.35)) for each dollar he pays in electric bill. Setting aside the tax effect, the overwhelming majority of residential customers are net debtors, if only because most home-owners have outstanding home mortgages. The Federal Reserve reports that the average April rate for new conventional 30-year mortgages was 5.92 percent,[6] probably about the same as PSE's cost of short-term borrowing. But that is the rate for "prime" mortgages. Other, more risky "balloon" and "interest only" mortgages bear higher interest rates.

At the margin, however, the cost of money to residential customers is considerably higher. Second trust mortgages bear somewhat higher interest rates than first trust mortgages. Higher still is the cost of credit card debt, ranging up to 22.4 percent.[7] Highest of all is the cost of money to residential customers who simply cannot pay any more than their incomes will allow. For them, the cost of

[6] Federal Reserve Statistical Release, *H.15 Select Interest Rates (Weekly)*, (May 5, 2008), Available at: www.federalreserve.gov/releases/h15/20080505.
[7] Available at: www.capitalone.com/creditcards/products.

money is the burden imposed by doing without critical life necessities: food, clothing and shelter.

It is clear from the foregoing that ratepayers are not adequately compensated for the time value of their money when the nominal, undiscounted value of future removal costs is subtracted from the rate base. That is because the TIFCA procedure front-loads those accruals and because the time value in money is much higher for ratepayers than it is for PSE.

Q: What is the solution to this failure to recognize the present value of future costs?

A: The solution to the failure of TIFCA to recognize the present value of future costs is found in Statement of Financial Accounting Standards No. 143 (SFAS 143), *Accounting for Asset Retirement Obligations*, issued by the Financial Accounting Standards Board in June 2001.

Q: Do PSE's removal costs qualify as legal retirement obligations?

A: Some of PSE's removal costs are legal obligations, particularly where there is potential environmental degradation when the assets are retired. Most removal costs, however, have not been declared "Asset Retirement Obligations" subject to SFAS 143.

Q: Does this mean that SFAS 143 is irrelevant to the issues in this proceeding?

A: No. To the contrary, the principle embodied in SFAS 143 applies as much to non-legal removal costs as to legal removal costs. That principle is that any current recognition of future removal costs must reflect the time value of money while still ensuring that the utility ultimately accrues the full amount of the removal costs over the life of the plant.

Q: Can SFAS 143 procedures be applied to PSE's non-legal removal costs?

A: Yes. The same procedures can be applied to non-legal removal cost obligations as to legal obligations.

Q: Have you implemented the SFAS 143 procedures for PSE's mass property removal costs?

A: Yes. Schedule 3 in my Exhibit No. ___ (CWK-5) is a sample worksheet on which I have implemented the SFAS 143 procedures for the plant in Account 380 – Gas Services. Because this is a mass property account, I must apply these procedures separately to each vintage (year of placement) of plant. I have accepted Mr. Clarke's 75 percent net removal cost ratio and have applied it to each vintage of plant to derive the estimated future removal cost amount. Then, I have discounted these costs back to the year of placement, using PSE's most recently approved cost of capital as the discount factor. I divide this value by the average service life of the account to derive the current year's depreciation – the first of the two components of the SFAS 143 expense.

I next determine the average remaining years for each vintage and calculate the accretion in the present value of that vintage's removal costs from the current year to the next year. In Column Q of Schedule 3, I present each vintage's SFAS 143 expense. The sum of these expenses is the appropriate removal cost allowance for the account. I then divide that amount by the December 31, 2006 plant balance to derive the increment in the depreciation rate for removal costs. This value is transferred to Column G "Removal Cost Accrual Rate," on Schedule 1 of Exhibit No. ___ (CWK-5).

Q: **Have you applied the SFAS 143 procedures to the terminal dismantlement costs of PSE's production plant accounts?**

A: Yes. The procedures are the same for terminal dismantlement costs, with two notable differences. First, the dismantlement costs proposed by Mr. Clarke are expressed in 2006 dollars, and the SFAS 143 procedures call for them to be inflated to an estimate of the actual cost at time of retirement. I have performed this inflation using the remaining life of the plants and an inflation factor derived from the average annual increases in the Handy Whitman cost indexes during the last five years. I then discount this forecast future cost back to the year of the plant's installation.

The other difference is that, unlike the mass property accounts with continuous additions and retirements, the production plants will each retire in a specific year. For this reason, the SFAS 143 removal cost allowance will increase each year as the plant retirement year approaches. I have assumed that the depreciation rates set in this case will be applied during the next five years, so I have used the plant remaining lives as of the mid-point of the next five-year period, which is the year 2010. Schedule 4 in Exhibit No. ___ (CWK-4) is the worksheet for this calculation.

Q: Aside from reflecting the present value of future costs, is there any other reason to discount PSE's removal cost estimates?

A: Yes. These removal cost estimates are very, very uncertain. Indeed, the only certainty is that they will be incorrect. The mass property removal costs are based on a very shaky and unstable assumed relationship between retirements and removal costs. The production plant dismantlement costs are even less reliable, for two reasons. First, there has been no formal study of dismantlement costs. Second, they are based on shaky assumptions as regards the nature and timing of dismantlement.

Mass property ratios are shaky due to measurement, not causality. Retirements are valued at their original cost, and that cost varies radically over time. In any given year, the age of retired plant will differ from the age during the previous and the subsequent years. For example, even over a period of five years, one cannot assume that the retired plant represents a normal dispersion of retirement values around some representative average.

Then, there is the fact that neither retirements nor removal costs are homogeneous. Many plant accounts consist of a variety of items having different unit costs. The mix of these items retired each year will differ from previous and future years. The same is true of removal costs. Because the mix of plant retired differs each year, the mix of removal activities also differs. The result of these variations is an extremely unstable relationship between retirements and removal costs. When that relationship is used to forecast future removal costs, the result is a very uncertain forecast.

Q: Why do you say that the dismantlement cost estimates reflect shaky assumptions about the nature and timing of dismantlement?

A: Mr. Clarke's report concedes that there are no studies of the cost to dismantle its production and hydro plants.[8] He therefore simply adopts the existing dismantlement ratios. There is no evidence in the record of this case (or any other, to judge from PSE's responses to data requests[9]) to support these ratios. Additionally, the implicit assumption of Mr. Clarke's ratios is that the plants will be dismantled and the site cleared when the existing generating units are retired. I question this assumption. The best use for any steam production plant site where the generating units have worn out is as a site for new generating units. Not only are many of the basic structures still usable, but the common facilities for fuel handling and storage, water movement and treatment, and transportation remain in place. Perhaps more important, the site is already connected into the transmission grid and bears the requisite environmental and zoning approvals.

The same condition applies to the hydro plants. The service lives of the hydro plants are based on the remaining lives of their FERC licenses. These licenses can be renewed, so that the basic structures, dams and waterways will continue in operation, even if the generating equipment is replaced. However, Mr. Clarke's 25

[8] See PSE Response to WUTC Staff Data Request No. 20, Attachment A.
[9] *See* PSE Response to Public Counsel Data Request No. 179 and to WUTC Staff Data Request No. 020.

percent removal cost ratios apply to the structures, dams, reservoirs, and waterways accounts.

Given the advantages of existing sites, it would be economically irrational for the PSE to totally dismantle every one of its retired generating plants and clear the site.

Q: Do you have any objective evidence to support these opinions?

A: Yes. In 1998, our firm surveyed the disposition of all steam units over 50 MW retired in the United States during the previous decade. There were 67 of these units at 37 different locations. Fifty of them, retired in 25 separate locations, were in plants where other steam units continued in operation. Most of these retired units had not been dismantled, and all of the plants, including their basic structures, continued in use. Another 6 units in 5 locations were in plants where combustion turbines, combined cycle units or internal combustion units continued to operate. Only 11 units in 7 locations were fully retired. Among these retired plants, we were able to identify only two, containing five units, that had been fully dismantled. Yet even here, the dismantled plant was not necessarily returned to "greenfield" status. In one case the stack and some of the buildings were integrated into a local development project.

Q: How does the uncertainty of PSE's removal cost estimates affect the calculation of removal cost allowances?

A: Four years following the issuance of SFAS 143, the Financial Accounting Standards Board issued FASB Interpretation No. 47, intended to clarify SFAS 143 in cases where the entity is uncertain as to the timing or method of meeting its retirement obligation. This interpretation states as follows:

> Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists.[10]

It appears from this directive that even disregarding the issue of the present value of future cost, the uncertainty of PSE's removal cost estimates would justify a substantial discounting of their value.

Q: Are there any other jurisdictions that have adopted the present value approach you have recommended for treating removal costs?

A: Yes. In July of last year, the Maryland Public Service Commission adopted the present value approach in two decisions involving the Potomac Electric Power Company[11] and the Delmarva Light & Power Company.[12] In June, the Michigan Public Service Commission imposed a requirement that each utility compute both discounted and undiscounted removal costs when developing its depreciation rates.[13]

Q: What removal cost ratios do you recommend?

A: I am concerned that the heavy discounting of future removal costs may fail to generate sufficient allowances to cover the current cost of removing plant. This is particularly true of mass property electric accounts, where PSE's removal cost

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[10] Financial Accounting Standards Board, FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*, (March 2005), Summary.

[11] Maryland P.S.C. Order No. 81517, Case No. 9092, (July 19, 2007).

[12] Maryland P.S.C. Order No. 81518, Case No. 9093, (July 19, 2007).

[13] Michigan P.S.C. Case No. U-14292, Opinion and Order, (June 26, 2007).

ratios are relatively low compared to the TIFCA-based removal cost ratios that I have observed in analyzing other electric utility company depreciation studies.

Accordingly, I have compared the removal allowances that result from the application of the present value technique with the Company's actual average annual removal costs during the last five years (2002-2006). This comparison is presented in Schedule 5 of Exhibit No. ___ (CWK-4) for electric plant and in Schedule 4 of Exhibit No. ___ (CWK-5) for gas plant. I find that all of the present value allowances for gas plant and electric transmission plant recover as much or more revenue than actual 2002-2006 removal cost experience. However, for all but two of the electric distribution accounts, actual removal costs during the 2002-2006 period exceeded the allowances that would be derived from the application of the present value procedure. For these accounts, I recommend that removal cost allowances be based on the average experience of the last five years.

Q: Is there any precedent for using the last five years' average removal cost experience as the basis for removal cost allowances?

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A: Yes. This procedure is used for all utilities in Pennsylvania[14] and for electric utilities in New Jersey[15], Delaware[16] and Georgia.[17]

VIII. CONCLUSION

Q: Can you please summarize the results of your findings?

A: Schedule 5 of Exhibit ____(CWK-4) applies the depreciation rates identified in Schedule 1 to the test year plant balances. It reveals that, based on my review of Mr. Clarke's depreciation study and my independent analysis of proper deprecation treatment for production plant lives and salvage and retirement costs, I conclude that PSE's depreciation expense is overstated by $19,811,503 for electric plant. Schedule 4 of Exhibit _____(CWK-5) shows that test year depreciation for gas plant is overstated by $20,380,520. I have asked Mr. Majoros to include these adjustments in his calculation of PSE's revenue requirements.

Q: Does this complete your testimony?

A: Yes, it does.

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14 *Penn Sheraton, et.al. v. Pennsylvania Public Utilities Commission*, 198 Pa.Super. 618, 184 A.2d 324, (1962).

15 I/M/O Rockland Electric Company, BPU Docket Nos. ER02080614 and ER02100724, Initial Decision, June 10, 2003 and Summary Order, (July 31, 2003). I/M/O Atlantic City Electric Company, BPU Docket Nos. ER03020110, ER04060423, EO03020091 and EM02090633, Decision and Order Adopting Initial Decision and Stipulation of Settlement, (May 26, 2005). I/M/O Jersey Central Power & Light Company, BPU Docket Nos. ER0208056, ER0208057, EO02070417 and ER02030173, Summary Order, (August 1, 2003). I/M/O Public Service Electric and Gas Company, BPU Docket No. GR05100845, Decision and Order Adopting Initial Decision and Stipulation of Settlement, (November 11, 2006), p. 4.

16 Delaware PSC Order No. 6930, Case No. 05-304, signed June 6, 2006, ¶ 174.

17 Georgia PSC Docket No. 4007-U, (1991).