BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

DOCKETS UE-190529 & UG-190530 (*Consolidated*)

RESPONSE TESTIMONY OF MARK E. GARRETT
ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT MEG-1T

NOVEMBER 22, 2019

DOCKETS UE-190529 and UG-190530 (*Consolidated*)

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RESPONSE TESTIMONY OF MARK E. GARRETT

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I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q. Please state your name and business address.

A. My name is Mark Garrett. I am the President of Garrett Group Consulting Inc. an Oklahoma based firm specializing in public utility regulation, litigation, and consulting services. My business address is 4028 Oakdale Farm Circle, Edmond, Oklahoma 73013.

Q. Please describe your educational background and your professional experience related to utility regulation.

A. I am an attorney and a certified public accountant. I work as a consultant in the area of public utility regulation. I received my bachelor's degree from the University of Oklahoma and completed postgraduate hours at the Stephen F. Austin State University and at the University of Texas at Arlington and Pan American. I received my juris doctorate degree from Oklahoma City University Law School and was admitted to the Oklahoma Bar in 1997. I am a Certified Public Accountant licensed in the States of Texas and Oklahoma with a background in public accounting, private industry, and utility regulation. In public accounting, as a staff auditor for a firm in Dallas, I primarily audited financial institutions in Texas. In private industry, as controller for a mid-sized ($300 million) corporation in Dallas, I managed the corporate accounting function, including general ledger, accounts payable, financial reporting, audits, tax returns, budgets, projections, and supervision of accounting personnel. In utility regulation, I served as an auditor in the Public Utility Division of the Oklahoma Corporation Commission from 1991 to 1995. In that position, I managed the audits of major gas and electric utility companies in Oklahoma. Before leaving the Oklahoma commission I served as the personal aide to Commissioner Bob Anthony. Since leaving the Commission, I have worked on rate cases and other regulatory proceedings on behalf of various consumers and consumer groups. I have provided testimony before the commissions in the states of Alaska, Arizona, Arkansas, Colorado, Florida, Indiana, Massachusetts, Nevada, Oklahoma, Texas, Utah, and Washington. My qualifications were accepted in each of those states.

My clients primarily include large industrial customers, large gaming customers in Nevada, large hospitals and hospital groups, universities, cities, large commercial customers and solar industry interveners. I have also testified on behalf of commission staffs and offices of attorneys general in the states of Indiana, Nevada, Oklahoma, Washington, and Utah. A more complete description of my education and experience is provided in Exhibit MEG-2.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Public Counsel Unit of the Washington Attorney General's Office ("Public Counsel").

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

A. Garrett Group Consulting Inc. has been engaged to review the general rate case filing of Puget Sound Energy (PSE or "Company"), and to present recommendations and ratemaking policy considerations related to the Company's proposed revenue requirement and attrition adjustments for its electric and gas utilities. My testimony presents Public Counsel's recommendations regarding the Company's revenue requirement and attrition adjustment.

Q. Please summarize the requested rate increases of PSE and the rate impact of Public Counsel's recommendations.

A. PSE has requested a total rate increase of $205.4 million, comprised of an increase of $139.9 million for its electric utility and an increase of $65.5 million for its gas utility. Public Counsel's witnesses recommend several adjustments which result in an overall recommended rate *decrease* of $30.9 million, as shown in the table below.

Table 1: Summary of Public Counsel's Recommendations (Millions)

	Electric	**Gas**	**Total**
PSE's Total Increase Requested	$139.9	$65.5	$205.4
Public Counsel's Proposed Adjustment to Requested Increase	-$176.6	-$59.7	-$236.3
Recommended Increase (Decrease)	**-$36.7**	**$5.8**	**-$30.9**

Public Counsel recommends the following:

- PSE's authorized rate of return be set at 7.07 percent.
- The Commission not allow recovery of projected cost increases beyond the pro forma year ended June 2019.
- All excess deferred income taxes be returned to ratepayers, and that unprotected excess deferred taxes be amortized over a two-year period.
- A sharing of incentive compensation so that financially based incentives are borne by shareholders rather than ratepayers.
- Public Counsel recommends several power cost adjustments

- The Commission should reject the Company's proposed cost increases related to its Advanced Metering Infrastructure (AMI).
- The Commission should reject a portion of the Get to Zero (GTZ) initiative.

II. PSE'S RATE PROPOSAL AND ATTRITION ADJUSTMENT

Q. What does the Company propose with respect to its requested rate increase?

A. The Company has proposed multi-tiered adjustments to achieve its requested rate increase. PSE started with its operating results for 2018 and its average of the monthly average (AMA) rate base for the 13 months ended December 31, 2018. The Company then made several restating adjustments to recognize changes that occurred <u>during</u> the test year. Through another restating adjustment, average net plant in service was adjusted to end of period (EOP) balances as of December 31, 2018. PSE then made several pro forma adjustments for changes it expects in the post-test year period, including plant expected to be in service by June 30, 2019.[1] Finally, the Company proposed an attrition adjustment in addition to the increases expected for the post-test year period.[2] The attrition adjustment could be better described as a projected or forecasted test year for the rate effective period going out through April 2021. The impacts of the various adjustments are shown in the table below.[3]

[1] *See* Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T at 5:3 – 6:18.
[2] *See Id*. at 4:8-22.
[3] *See Id*. at 2:9-12.

Table 2: PSE's Proposed Rate Increases (Millions)

	Electric	Gas	Total
2018 Test Year	$7.7	$59.4	$67.1
Restating Adjustments (EOP 2018)	$54.1	$12.7	$66.8
Restated Test Year	$61.8	$72.1	$133.9
Pro Forma Adjustments (to 6/2019)	$42.8	$14.0	$56.8
Adjusted Pro Forma Year	$104.5	$86.1	$190.6
Changes to Other Rate Adj.	-$3.1	-$32.4	-$35.5
Attrition Adjustment (to 4/2021)	$44.5	$22.1	$66.6
Reduction to Requested Increase	-$6.0	-$10.4	-$16.4
Total Increase Requested	**$139.9**	**$65.5**	**$205.4**

Q. Does the Company's analysis conform to a customary ratemaking approach that is based on an historical test year?

A. No. PSE's analysis does not conform to a customary ratemaking approach based on a historical test year. Typically, a modified test year approach synchronizes the major cost components of the revenue requirement – rate base, revenues, operating expenses, depreciation and taxes – at a given point in time – a test year. Further, this approach only allows adjustments for known and measurable changes that occur: (1) during the test year or (2) shortly after the test year cut off to not disturb the alignment of these important ratemaking components. The Company's analysis starts with a historical test year identified as 2018, but projects cost increases through April 2021, two years after the test year for many cost components.

Q. Has this Commission expressed concerns about using projected future levels of expense and capital expenditures rather than historical costs as the basis for setting rates?

A. Yes. In its order for Avista's 2015 rate case (Dockets UE-150204 and UG-150205), the Commission stated:

> [We] are concerned about authorizing a practice that simply projects future levels of expense and capital expenditures that may, as multiple commenters point out, "become a 'self-fulfilling prophecy' where there is an incentive for rates of capital expenditure to be driven by an effort to match earlier projections."[4]

The Commission has also expressly rejected using a future test year approach to ratemaking.[5] PSE's requested rate increase in this case, as described above, is based upon cost projections into future periods. This request for a substantial rate increase based on projected future levels of expense is a significant cause for concern.[6]

Q. Is the Company presenting another ratemaking approach in this case?

A. Yes. PSE is also proposing an attrition adjustment in addition to utilizing future projected costs.

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[4] *WUTC v. Avista Corp*., Dockets UE-150204 & UG-150205, Final Order 5 ¶ 119 at 44 (Jan. 6, 2016) (footnote omitted).

[5] *WUTC v. Pacific Power & Light Co.,* Docket UE-140762, Order 08 ¶ 8 (Mar. 25, 2015); *WUTC v. Puget Sound Energy*, Dockets UE-111048 and UG-111049, Order 08 ¶¶ 96-98 (May 7, 2012).

[6] *WUTC v. Avista Corp.,* Dockets UE-160228 and UG-160229, Order 06 ¶ 68 (Dec. 15, 2016) (Avista's results in recent years appears to be the realization of the Commission's earlier expressed concern that authorizing a practice that simply projects future levels of expense and capital expenditures may become a self-fulfilling prophecy where capital expenditures are driven by an effort to match earlier projections.).

Q. What is an attrition adjustment?

A. Conceptually, attrition adjustments are an add-on to the revenue requirement that would otherwise be determined in a rate case. The idea is that without the adjustment, the utility's expected investment and operating cost levels will outpace revenues, leaving the utility without a reasonable opportunity to earn its authorized return.

Q. Is the concept of attrition contrary to the customary ratemaking formula?

A. Yes. Since the Commission serves as the surrogate for competition, the ratemaking process should, to the extent possible, attempt to produce the efficiencies obtained in a truly competitive market. In a competitive market, an individual firm is not able to increase its prices merely because its costs are rising. Absent special circumstances, attrition adjustments are contrary to the manner in which the competitive market functions, and therefore, contrary to the ordinary ratemaking formula.

Q. What is the Company's rationale for using a projected test year followed by additional attrition adjustments for the rate effective period?

A. The Company's rationale is set forth in the testimony of Ronald J. Amen. He discusses past rate cases, court rulings, and legislative actions related to attrition adjustments. His conclusion is that revenues are not keeping up with costs. Mr. Amen makes the following statement regarding the need for attrition adjustments:

> Attrition occurs when a utility's costs grow at a faster rate than the utility's revenues, thus eroding the regulated utility's opportunity to achieve a reasonable rate of return. It occurs when the relationships between costs, revenues and rate base established in a historical test year do not hold through the rate-effective period and result in a mismatch between revenues, expenses, and capital investment. While historically attrition was often due to inflation or an exceptionally large amount of production plant

> construction, the Commission has recognized that we have entered into a "new normal" in which utilities are making increased capital investments in non-revenue generating distribution plant in an environment of low load growth, which is causing attrition.[7]

This statement leaves the impression that utilities across the country are filing for significant rate increases each year to keep up with cost level escalations that are out of their control. The truth is attrition adjustments largely fell out of vogue in the 1980s.

Q. Was there a time when attrition adjustments were common for regulated utilities?

A. In the 1980s, attrition adjustments were more common because of the exceedingly high annual inflation rates experienced at that time across the country. Inflation was a serious factor in the 1970s and the OPEC oil embargo amplified that problem. Utilities moved from low cost petroleum and natural gas fueled power plants to coal and nuclear generation which resulted in large rate increases in the late 1970s and 1980s. This was the era in which attrition adjustments based on inflation were more broadly utilized.

During this era, some utilities were granted attrition adjustments to counterbalance these inflationary cost increases due to the unavoidable rising costs of providing service. That is not the case today, though. Instead, we have experienced very low rates of inflation for many years now (see Table 3 below). In my experience, attrition adjustments are an artifact of the past that is no longer needed in today's economic environment.

[7] *See* Prefiled Direct Testimony of Ronald J. Amen, Exh. RJA-1T at 16:16-25.

Q. What have the inflation trends been over the last several years?

A. The following table provides the annual rates of inflation as measured by the Producer Price Index (PPI) and Consumer Price Index (CPI) over the last several years:

Table 3 - Annual Inflation Rates[8]

Year	PPI	CPI
12 Mo. 9/2019	1.4%	1.7%
2018	2.5%	1.9%
2017	2.5%	2.1%
2016	1.6%	2.1%
2015	-1.1%	0.7%
2014	0.9%	0.8%
2013	1.2%	1.5%
2012	1.9%	1.7%
2011	3.2%	3.0%
2010	2.8%	1.5%
2009	N/A	2.7%
2008	N/A	0.1%

As shown in the table above, inflation is far below the level at which attrition adjustments should occur for ongoing cost increases in the ordinary course of business.

Q. Have you found cost escalations similar to those presented by PSE to be the norm in jurisdictions across the country?

A. No. This has not been my experience. Instead, I have seen many instances in which the cost of capital has been declining sharply over the past several years and many utilities have been able to avoid substantial rate increases due to lower debt and equity costs. In

[8] Source: US Department of Labor Bureau of Labor Statistics, https://www.bls.gov.

some cases, for example, when companies are faced with significant costs associated with environmental compliance mandates beyond their control, I have seen commissions award narrowly tailored rate increases and other measures to address the special circumstances. In this case, however, PSE's requested rate increases are *not* the result of environmental mandates or cost increases beyond the utility's control. The types of discretionary expenditures for which PSE seeks recovery in this case do not warrant the extraordinary rate treatment the Company is seeking.[9]

Q. Briefly describe the approaches you have seen in other jurisdictions.

In most of the states in which I regularly practice, commissions adhere to the use of standard historical test year approaches. They typically do not significantly alter their long-standing ratemaking methodologies or standards because a utility is experiencing cost increases, even if environmental compliance mandates drive cost increases beyond the utility's control. Thus, while the utilities in Oklahoma and Texas have received some, albeit small, rate increases related to environmental compliance costs, the utilities in Nevada have actually received rate ***decreases*** over the past several years. In the scores of rate cases I have been involved in, I have not seen commissions in these jurisdictions alter their approach to provide the type of extraordinary relief PSE is seeking in this case. To the contrary, the commissions have continued to require companies to provide historical cost data and test year cutoffs as a general rule.

[9] PSE's proposed rate increases are related, in large part, to PSE's replacement of existing distribution assets and its implementation of the Get to Zero program, neither of which are governmental mandates.

Q. In your experience, what approach do commissions in other jurisdictions take when a utility requests an allowance for costs incurred after test year end?

A. In Oklahoma, the commission recognizes known and measurable changes up to six months after test year end. Any change after that date is not included, and the cutoff is strictly observed. This means that any change included in rates has actually occurred by the time the case goes to hearing. Costs are not projected.

In Nevada, the same is true, except the cutoff is five months after test year end. Thus, all rate base, revenues, operating expense, depreciation and taxes are updated to the cutoff date. No capital additions or expenses incurred after that cutoff date are allowed in rates, as post test year periods in Oklahoma and Nevada are statutorily prohibited. In Texas, test year end is fairly rigidly observed for rate base accounts.

Q. What is the accepted ratemaking approach in Washington?

A. My understanding is that the Washington Utilities and Transportation Commission uses a *Modified Historical Test Year with Pro Forma Adjustments* approach, which means that the ratemaking process starts with an historical test year adjusted for *known and measurable changes* that occur during the test year or shortly after test year end.[10] On occasion, when warranted by the circumstances, the Commission has allowed expenses or investments that occurred after the test year to be included in the ratemaking formula. The Commission has also, in some circumstances, approved more extraordinary measures such as attrition adjustments, when necessary to recover cost increases that are beyond

[10] *See WUTC v. Avista Corp.,* Dockets UE-160228 and UG-160229, Order 06, Final Order Rejecting Tariff Filing at 47 (Dec. 15, 2016).

the control of management. However, the standard for an attrition adjustment is clear. According to the Commission:

> It is necessary for Avista and any other utility seeking an attrition adjustment to demonstrate that its need to invest in non-revenue generating plant, particularly distribution plant, is so necessary and immediate as to be beyond its control.[11]

Q. Do the Company's costs in this case satisfy the Commission's standard?

A. No. PSE's projected cost increases are related to costs that are squarely within the control of management. The cost increases in this case are primarily for replacement of distribution plant and other operating cost increases. In my experience, costs that are beyond the control of management would generally include: acts of God (such as storms), acts of governmental authorities (such as environmental mandates), commodity cost increases (such as natural gas price spikes), or unforeseen catastrophes (such as pipeline explosions caused by third parties that are not covered by insurance). It would be very unusual for utility management to assert that they are unable to control ongoing levels of capital investment and operating costs of the company.

Q. Does the Company demonstrate a need for an attrition adjustment that is "so necessary and immediate as to be beyond its control" as the Commission requires?

A. No. The Company does not demonstrate any immediate need or argue that its costs are beyond the Company's control. Instead, Mr. Amen argues that the Commission no longer requires a showing of extraordinary circumstances or extreme financial distress to justify an attrition adjustment, but merely requires that the utility show that it has under-earned

[11] *See WUTC v. Avista Corp.,* Dockets UE-160228 and UG-160229, Order 07, Order on Reconsideration ¶ 29 (Feb. 27, 2017) (quoting Dockets UE-150204 and UG-150205, Order 05 ¶ 110).

and will likely not be able to achieve its authorized return absent an attrition adjustment.[12]

The concern with lowering the standard in the manner the Company suggests is – as this Commission has recognized – attrition adjustment increases become self-fulfilling prophecies and are a disincentive for cost control measures. Given additional money to spend, management will spend it and continue in future proceedings to seek increases based upon extraordinary ratemaking measures.

Q. Are the Company's attempts to avoid regulatory lag based on projected cost increases appropriate?

A. No. Regulatory lag is by far the Commission's best tool for ensuring that regulated utilities control costs. When rates are set to recover a certain level of costs that reflect adjustments for known and measurable changes, the utility has every incentive to ensure that unavoidable cost increases are offset with corresponding cost decreases. Regulatory lag causes utilities to look for every efficiency measure available and this is what companies in competitive markets must do all the time. Since the Commission serves as the surrogate for competition, it is important for the Commission not to abandon its best tool for imitating the market. Utilities routinely attempt to eliminate regulatory lag, but these attempts should be rejected.

Whenever a regulated utility can no longer manage its company in a manner that achieves a reasonable return, it has the remedy of filing a rate case. This remedy is not available to companies that operate in competitive markets. This gives regulated utilities

[12] *See* Amen, Exh. RJA-1T at 17:2-7.

a safety net that competitive companies do not enjoy. Thus, the slight discomfort that comes from regulatory lag should be left in place to encourage regulated companies to operate as efficiently as they can, in effect, to operate as efficiently as they would have in a competitive environment. On an ongoing basis, revenue growth and productivity gains (i.e., reduced operating costs) encouraged through regulatory lag are generally sufficient to sustain a utility's earnings through the rate-effective period. If cost increases truly cannot be sufficiently offset with increased revenues and operating efficiencies, the utility has the option to file a rate case.

For PSE, however, there are many opportunities during the rate effective period that have the prospect of significantly lowering the Company's costs, which are not accounted for in the Company's current filing. These omissions raise questions as to whether the Company will experience any revenue deficiency if its ROE and capital structure are set at appropriate levels. Based on my review of the application, the Company has not met its burden to show that its projected capital investments and cost escalations during the rate-effective period are beyond its control or sufficient to justify the relief it seeks.

Q. Has PSE been significantly under earning for the last several years?

A. No. PSE's Commission Basis Reports do not support a finding that PSE has significant periods of under-earning. To the contrary, the data shows PSE has over-earned in four of the last five years, as shown in the following table:

Table 4 – PSE's Actual vs. Earned Returns				
Year	Electric Authorized ROR	Electric Actual ROR	Gas Authorized ROR	Gas Actual ROR
2014	7.77%	7.74%	7.80%	7.87%
2015	7.77%	8.05%	7.80%	8.17%
2016	7.77%	8.06%	7.77%	7.93%
2017	7.76%	8.17%	7.76%	8.16%
2018	7.60%	7.12%	7.60%	5.64%

Q. PSE argues that it would have under-earned throughout this period instead of over earning if the Company had not received preferential rate treatment.[13] Do you agree?

A: No. PSE should have, and likely would have, adjusted its spending in those years to better match its resources. This is what would have happened in a competitive environment, which is the standard to which PSE must be held.

Q. Will there be potential cost offsets for the Company during the period covered by the attrition adjustment, effectively July 2019 through March 2021, not yet identified by the Company?

A. Yes. There may be many. For example, the Federal Reserve recently cut interest rates, once in July and again in September, and it indicates there could be more cuts in the future. These rate cuts mean that the Company's borrowing costs could be much lower in the future. In my opinion, it would be inappropriate to increase rates, through an attrition

[13] *See* Amen, Exh. RJA-1T at 18:7-12.

adjustment, for potential cost increases in the future, while ignoring significant potential cost decreases over the same period of time.

III. PSE'S OTHER POST TEST YEAR ADJUSTMENTS

Q. Please discuss the post-test year adjustments the Company has proposed.

A. PSE has included several adjustments for the post-test year period, including those identified as pro forma adjustments and the attrition adjustment. The pro forma adjustments have been described as an update to June 30, 2019, on an AMA basis, while the attrition adjustments project rate base and operating income into the rate year. The rate year begins in May 2020 and extends through April 2021. Some of the pro forma adjustments are important and timely, such as the adjustment to recognize the Microsoft special contract that has already been implemented. Other pro forma adjustments seem to reach well beyond the identified pro forma period, such as the wage increase adjustment, which includes pay increase dates that extend to October 2020. The adjustments that extend past the update period are duplicated by the attrition adjustment, which projects costs into the rate year and overstate the revenue requirement for that time frame.

Q. What is your recommendation regarding the prospective costs that PSE has included to support their rate increase?

A. I recommend that post-test year adjustments be limited to the stated pro forma period on an AMA basis. I am proposing alternative adjustments for the pro forma period, limited to the update of the plant related investments, the adjustment for pay increases within the pro forma period, the amortization of unprotected EDIT, and an adjustment for the tax benefit of interest. These adjustments replace the pro forma rate base and net operating income adjustments proposed by the Company, except those for revenues and expenses (6.01 EP), temperature normalization (6.02 EP), property and liability insurance (6.14 EP), and Montana tax, storm damage, and removal of EIM (7.01 EP, 7.02 EP, 7.05 EP, and 7.08 EP).

Q. Please discuss your adjustment to update the plant related costs on an AMA basis for the pro forma period.

A. This adjustment updates plant in service, accumulated depreciation, accumulated deferred income taxes, and depreciation expense on an AMA basis for the pro forma period ended June 30, 2019. These adjustments are based on the actual account balances for the test year and pro forma period, as provided in the Company's Supplemental Data Responses to Public Counsel Data Request Nos. 230, 232, and 234, and as shown in Exhibit MEG-3, WP-3 AMA.

Q. What is the amount of your adjustments to update plant for the pro forma period?

A. The adjustment to plant in service, accumulated depreciation, and accumulated deferred income taxes increases rate base by $121.4 million for the electric utility,[14] and an adjustment of $117.6 million for the gas utility.[15] These adjustments also update the associated depreciation expense and income tax expense for the respective utilities.

[14] *See* Mark E. Garrett, Exh. MEG-3, Workpaper-3 AMA Update.
[15] *See* Garrett, Exh. MEG-4, WP-1 AMA Update.

Q. What adjustments proposed by PSE do these adjustments replace?

A. These adjustments replace the PSE restating end of period adjustments to plant and depreciation expense, adjustments (6.18 ER and 6.19 ER for electric, 6.18 GR and 6.19 GR for gas) and the pro forma adjustments for AMI, GTZ, Public Improvement, and HR Tops (6.22 EP, 6.24 EP, 6.27 EP, 6.29 EP, 6.22 GP, 6.24 GP, 6.27 GP, and 6.29 GP), as well as the rate base components of the attrition adjustment. This adjustment includes the pro forma year updates for these projects and does not represent a recommendation to disallow those costs. The AMI and GTZ projects, for which we do recommend a disallowance, will be discussed later in my testimony.

Q. Please discuss the wage increase adjustment that you are proposing.

A. PSE has proposed to include wage increases during and after the test year. The Company has included pay increases that will be implemented well after the end of the pro forma period, as late as October 2020. I recommend that the pro forma period adjustments reflect costs subject to base rate recovery uniformly and avoid the selective increases to certain expenses while ignoring other changes in cost levels that would offset those increases. I recommend that the wage increase adjustment be limited to the pro forma period.

Q. How did you calculate your pro forma period wage adjustment?

A. I used the Company's payroll adjustment spreadsheet[16] and adjusted it by removing the increases scheduled to be implemented after June 30, 2019. The revised spreadsheet then

[16] *See* Free, Workpaper 'NEW-PSE-WP-SEF-6.15E-6.15G-WageIncr-19GRC-06-2019.xlsx'.

calculated my recommended pay increase amounts to be included for the pro forma period.

Q. What is the amount of your adjustments to payroll expense?

A. These adjustments reduces the net operating income of the electric utility by $2.2 million, and by $0.6 million for the gas utility.

Q. Please discuss the adjustment to remove the costs associated with AMI.

A. This adjustment is based on the recommendations of Public Counsel witness Paul Alvarez. This adjustment removes the test year cost of the AMI investments, adjusted for the increase in plant related investment to June 30, 2019, on an AMA basis. This amount should be comparable to the amounts included in my adjusted June 30 2019, pro forma plant related accounts.

Q. What is the amount you recommend removing for the AMI investment and expenses?

A. This adjustment increases the electric utility net operating income by $6.8 million[17] and reduces the electric rate base by $56.2 million,[18] and it increase the gas utility net operating income by $3.3 million[19] and reduces the gas rate base by $21.9 million.[20]

Q. Please discuss the adjustment for the tax benefit of interest.

A. This adjustment is based on the adjustments I recommend to rate base. Those adjustments

[17] *See* Garrett, Exh. MEG-3 at 7.
[18] *Id*.
[19] *See* Garrett, Exh. MEG-4 at 7.
[20] *Id*.

reduce rate base, which in turn reduces the proportion of long-term debt interest allocable to the electric and gas utilities, effectively increasing income tax expense and reducing net operating income.

Q. What is the amount of the adjustment for the tax benefit of interest?

A. This adjustment reduces the electric utility net operating income by $2.1 million[21] and gas utility net operating income by $0.9 million.[22]

Q. Do you propose any other adjustments to the Company's revenue requirement?

A. Yes. I propose an adjustment to the Company's annual incentive compensation plan expense to remove the costs associated with financial measures within the plan. I also propose an adjustment to return the amortization of protected excess deferred income taxes (EDIT) that resulted from the Tax Cuts and Jobs Act ("TCJA") from January 2018 through February 2019 to ratepayers. These adjustments are discussed in the sections below.

IV. ANNUAL INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

Q. Please provide a brief description of PSE's annual incentive compensation plans.

A. PSE's annual incentive compensation plans is a formal written plan approved by senior management. In this application, PSE seeks to include in rates $9.106 million for electric

[21] *See* Garrett, Exh. MEG-3 at 8.
[22] *See* Garrett, Exh. MEG-4 at 8.

annual incentive expense and $4.389 million for gas annual incentive expense based on a four-year average expense level for the years 2015 through 2018.[23/24]

Q. Do Company witnesses discuss the annual incentive compensation plans in direct testimony?

A. Yes. PSE witness Thomas M. Hunt discusses the Company's Goals and Incentive Plan and Susan E. Free sponsors the Company's adjustments related to the incentive plan.[25]

Q. Do you agree with the Company's adjustment to use a four-year average for these costs?

A. Yes. With incentive compensation, it is standard practice to normalize test year levels to target levels. The target level for incentives is the best estimate of the anticipated ongoing level for these costs. More importantly, target level approximates market price before adjusting for financially based incentives. As such, target level is a starting point—i.e., the highest level that could be included in rates. Then, after that, any further adjustment, or disallowance, related to the reasonableness of the costs for ratemaking purposes is made. Here, the Company has adjusted to a four-year average, but the four-year average is a very close approximation of the target level, so I recommend that it be used as a starting point for any further adjustment.

[23] *See* Free, Workpaper 'NEW-PSE-WP-SEF-6.08E-6.08G-Incentive-19GRC-06-2019.xlsx'.
[24] *See* Free, Exh. SEF-1T at 29:10-22.
[25] *See* Prefiled Direct Testimony of Thomas M. Hunt, Exh. TMH-1T at 24:14 - 30:7; Free, Exh. SEF-1T at 29:10-22.

Q. How are incentive plan costs generally treated in Washington?

A. My understanding is that incentive compensation plans are evaluated on a case by case basis, and that incentives tied to operational efficiency or other measures that benefit ratepayers, if reasonable, are generally allowed in rates, and incentives that primarily benefit shareholders are disallowed.

Q. From your review of the Company's plans, do financial performance measures comprise a significant component of the incentive compensation metrics?

A. Yes. The Company's annual incentive plan is heavily dependent on financial performance measures. While the incentive award levels are based on a combination of earnings goals and operational goals, the ***funding*** for annual incentive compensation is based on PSE's earnings; specifically, Earnings before Interest, Taxes, Depreciation, and Amortization ("EBITDA").[26] Moreover, the plan also has a funding ***trigger,*** also based on PSE's EBITDA, so that if 90 percent of the EBITDA goal is not achieved, ***no*** incentive payment is be made in that year. The following table was included in the Company's incentive plan documentation:[27]

[26] *See* Hunt, Exh. TMH-1T at 27:15-19.
[27] *See* Hunt, Exh. TMH-7 at 1.

SHORT-TERM INCENTIVE PLAN

Plan Funding Pool Based on Safety and SQI Results And PSE Adjusted EBITDA Result

Safety and SQI Results	Financial Metric Versus Plan								
	<90%	*90%*	*95%*	*100%*	*105%*	*110%*	*120%*	*130%*	*135%*
	Incentive Pool As a % of Target Incentive								
				Target					
10/10	0%	50%	75%	100%	125.0%	137.5%	162.5%	187.5%	200.0%
9/10	0%	45%	68%	90%	112.5%	123.8%	123.8%	123.8%	123.8%
8/10	0%	40%	60%	80%	100%	100%	100%	100%	100%
7/10	0%	35%	53%	70%	70%	70%	70%	70%	70%
6/10	0%	30%	45%	60%	60%	60%	60%	60%	60%
5/10 or below	0%	0%	0%	0%	0%	0%	0%	0%	0%

This table shows that, under the Company's plan, the threshold for making any incentive payments, at all, is based on achieving 90 percent of the financial performance (earnings) target. Not only is there an EBITDA funding trigger (minimum threshold) of 90 percent, but the plan also provides for ***increasing*** levels of funding for employee incentives based on PSE's achievement of ***higher*** earnings levels. Thus, Company earnings, EBITDA, is by far the most important factor in determining whether incentive compensation will be paid and to what extent.

Q. How does the funding mechanism work?

A. The table above shows that if PSE achieves **90 percent** of its EBITDA target, and achieves 10 out of 10 of its operational goals, the incentive funding level is **50 percent**. If PSE achieves **100 percent** of its EBITDA target, and 10 out of 10 of its operational goals, the funding level is **100 percent**. If PSE achieves **135 percent** of its EBITDA target, and 10 out of 10 of its operational goals, the funding level is **200 percent**. Thus, as earnings increase, so does the funding level for incentives, so long as the initial earnings threshold has been met.

Q. Do incentive plans of this nature prioritize the interests of shareholders over the interests of customers?

A. Yes. Plans that are more heavily weighted towards earnings targets, such as plans with a financial-based funding mechanism, and especially plans with a financial-based trigger, prioritize the goal of maximizing shareholder wealth. These plans unquestionably benefit shareholders more than they do ratepayers. Moreover, from a ratemaking perspective, incentive plans with a financial trigger are particularly disturbing. With these plans, if the earnings threshold is not achieved, money collected from ratepayers for the purpose of paying employee incentives may not be paid to employees at all, but instead may be diverted to bolster shareholder returns.

Q. Are there other problems with the plan?

A. Yes. The Company's plan is also structured to benefit its highly compensated senior level employees more than its rank and file employees. According to PSE witness, Mr. Hunt, "Officers have higher incentive targets as a percentage of salary than other employees, reflecting the market levels of incentive pay, and therefore have more pay at risk."[28] In my experience, top heavy incentive compensation plans that have financially based funding triggers tend to promote the interests of shareholders more than the interests of ratepayers.

[28] *See* Hunt, Exh. TMH-1T at 27:10-12.

Q. Are you familiar with the regulatory treatment of annual incentive compensation plans with financial funding mechanisms and financial triggers?

A. Yes. I have testified in numerous regulatory proceedings involving American Electric Power's (AEP) in which regulatory commissions have disallowed a portion of AEP's incentive compensation plans, which have ***financial funding mechanisms and triggers*** similar to PSE's plan.

For example, since 2006 the Oklahoma Corporation Commission (OCC) has disallowed a portion of the annual incentive compensation of AEP's Public Service Company of Oklahoma ("PSO") because its plan has a financially based funding mechanism and an earnings trigger.[29] In AEP/PSO's 2015 rate case, Cause No. PUD 201500208, the Commission's order states:

> The ALJ adopts Staff and AG's recommendation that an adjustment be made to remove the portion of the Annual Incentive Program costs related to financial performance measures. In many jurisdictions, including Oklahoma, *the cost of incentive plans tied to financial performance measures generally are excluded for ratemaking purposes* for several reasons. *(See* Garrett Responsive Testimony, pp. *23-33). The evidence in this case established that the Company's incentive compensation is **funded** primarily based on the Company's financial performance (*75% earnings per share).
>
> The result of the above disallowances reduces the recoverable expenses of PSO by . . . $4,369,947 for short term incentive expense, which is 50% of the $8,739,895 requested by PSO.[30]

[29] *See* Final Order of the Oklahoma Corporation Commission (OCC), Cause No. PUD 200600285, page 145, in which the OCC disallowed 50 percent of the utility's annual incentive compensation expense. *See also*, *Application of Pub. Svc. Co. of Okla., an Okla. Corp., for an Adjustment in its Rates and Charges for Elec. Svc. in the State of Okla.*, Cause No. PUD 200800144, Final Order at 19-21 (2009).

[30] *See* Final Order in Cause No. PUD 201500208, adopting Report and Recommendation of the Administrative Law Judge, pages 161-162 (emphasis added). In PSO's 2017 general rate case, Cause No. 201700151, page 24, the OCC again disallowed 50 percent of PSO's short-term incentive plan.

In Texas, the Public Utility Commission's policy is even more stringent. It disallows 100 percent of annual incentives that are ***directly*** tied to financial performance measures, and disallows an additional 50 percent of the remaining incentives tied to operational measures, ***where the plan has a financial performance funding mechanism***.[31] In applying this approach to AEP's plan in the most recent Southwestern Electric Power Company ("SWEPCO") case, in Docket No. 46449, the Texas commission disallowed about 60 percent of the utility's annual incentive plan costs and made the following finding:

> **194.** The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because *financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services*.[32]

Q. Do you know of other utilities with incentive plans with financial performance triggers and funding mechanisms like PSE'S?

A. Yes. I am familiar with several utilities that provide incentives with financial funding mechanisms. They are listed below.

CenterPoint Houston has an incentive plan with a financial trigger and financial funding mechanism similar to PSE's. In its recent 2019 rate case before the Public Utility Commission of Texas, the ALJ recommended that 92 percent of the plan costs be disallowed, as a result of the commission's policy of disallowing 100 percent of plan costs with financial metrics and 50 percent of the plan costs with operational metrics

[31] *See Application of Southwestern Elec. Power Co. for Authority to Change Rates*, PUC Docket No. 43695, Order on Rehearing at 5-6 (Tex. PUC, 2016). *Also see*, SWEPCO Docket No. 46495, and Docket No 46449.
[32] *Application of Southwestern Elec. Power Co. for Authority to Change Rates*, PUC Docket No. 46449, Order on Rehearing at 34, Finding No. 194 (Mar. 19, 2018) (emphasis added).

where there is a financial trigger in the plan.[33]

<u>Southwestern Public Service Company ("SPS")</u> received a similar treatment in its last rate case, (Docket No. 43695). Although SPS initially removed what it asserted were the *<u>direct</u>* financially-based incentive costs, the commission required that *<u>all</u>* incentive costs tied to financial measures (direct and indirect) costs must be removed. The Commission's 2016 Final Order in that case disallowed 100 percent of short-term incentives directly tied to financial performance measures <u>and</u> 50 percent of the remaining incentives because they were tied to financial performance through an earnings-per-share funding mechanism.[34] The Commission stated:

> It is well-established that a utility may not include in its rates the costs of incentives that are tied to financial performance measures. The Commission agrees with the SOAH ALJs' characterization of the annual incentive plan as "complicated" and notes that when a utility elects to adopt a compensation plan that involves both financially-based and performance-based metrics, *<u>the utility still must show it has removed all aspects of the financially-based goals from its requested expense</u>*.[35]

In Arkansas, **<u>Entergy Arkansas, Inc. (EAI)</u>** receives similar treatment because its annual incentives contain a financial funding mechanism. The Arkansas Public Service Commission (APSC) disallows 50 percent of the short-term incentive plan costs in cases where the company's incentive compensation plans include a financial funding mechanism. In Docket No. 13-028-U the Commission stated:

> The Commission finds that EAI and Staff have failed to show that EAI's short-term, long-term and stock based incentive compensation provide ratepayer benefits to justify 100% inclusion in rates. The Commission agrees with both the AG and HHEG witnesses *<u>that most, if not all, of the</u>*

[33] *See Application for CenterPoint Houston Elec. for Authority to Change Rates*, Tex. PUC Docket No. 49421, Proposal for Decision at 431-432, ¶¶ 228-236 (Sept. 16, 2019).
[34] *See* Tex. PUC Docket No. 43695, Order on Rehearing at 5-6. This was the approach taken by the witness whose recommendations were adopted by the Commission.
[35] *Id*. at 5 (emphasis added).

> *short-term incentive costs are indirectly tied to financial performance through the EAM funding mechanism and, therefore, the Commission finds that ratepayers should bear no more than 50% of the costs*. The Commission finds that $8,087,877 in annual short-term incentive costs, and all other related payroll costs, should be removed from EAI's operating expenses in this proceeding. [36]

In Entergy's subsequent rate case, Docket No. 15-015-U, the Arkansas commission reversed a settlement agreement which disallowed only 25 percent of Entergy's short-term incentive plan costs, imposing instead its preferred 50 percent disallowance.[37]

Q. How does the treatment of short-term incentive costs in these jurisdictions compare with other jurisdictions' treatment of incentive compensation?

A. The policy of excluding a portion of short-term compensation costs is consistent with the majority of jurisdictions, including Washington. The results of an Incentive Compensation Survey of the 24 Western States[38] taken by the Garrett Group in 2007, and updated in 2009, 2011, 2015 and 2018, shows that a clear majority of the states surveyed follow the financial-performance rule, in which incentive payments associated with financial performance are excluded from rates. While some states disallow incentive pay using other criteria, and some states apply a sharing mechanism such as a 50 percent - 50 percent allocation, none of the jurisdictions surveyed allow full recovery of incentive compensation through rates as a general rule. The results of the survey are set forth at

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[36] *In re: Application Entergy Ark. For Approval of Changes in Rates for Retail Elec. Svc.*, Docket No. 13-028-U, Order No. 21 at 54 (Dec. 30. 2013) (emphasis added).
[37] *See In re: Application of Entergy Ark. For Approval of Changes in Rates for Retail Elec. Svc*., Docket No. 15-015-U, Order No.18 at 18-20 (Ark. Pub. Svc. Comm'n Feb. 23, 2016).
[38] The Garrett Group Incentive Compensation Survey of the 24 Western States is a telephonic survey that presents questions regarding regulatory policies and practices with respect to incentive compensation and documents the responses of commission staff representatives as to the ratemaking treatment and policies in each jurisdiction within the 24 Western States.

Exhibit MEG-3. The table below provides a summary of the survey results:

Garrett Group Consulting, Inc. 24 Western State Incentive Survey Results			
No Incentive Costs Allowed in Rates	**Financial Performance Rule Followed**	**Other Sharing Approach**	**Incentives Not at Issue**
Hawaii			
	Arizona		
	Arkansas		
	California		
	Idaho		
	Kansas		
	Louisiana		
	Minnesota		
	Missouri		
	Nebraska		
	Nevada		
	New Mexico		
	North Dakota		
	Oklahoma		
	Oregon		
	South Dakota		
	Texas		
	Utah		
	Washington		
	Wyoming		
		Alaska[39]	
		Colorado[40]	
			Iowa
			Montana

As shown in the table above, many of the western states disallow a portion of incentive compensation costs where the incentive plans contain both financial and operational

[39] Incentive compensation has not been an issue in the past, partly because most utilities in Alaska are municipalities and CO-OPs. In one recent case, however, the Commission approved incentives in rates, which may turn out to be an anomaly.
[40] Colorado followed the financial performance rule in the past. In one recent case, however, the Commission approved another approach, which may turn out to be an anomaly.

measures. Of those jurisdictions, several use a sharing approach to allocate costs between shareholders and ratepayers.

Q. Can you provide a brief synopsis of the incentive survey results?

A. Yes. A summary of the results is set forth below.

States that generally follow the Financial-Performance Rule:

Arizona The Commission deals with incentive compensation plans on a case by case basis. Evaluation centers on the criteria of benefit to customers. This treatment tends to make long-term programs harder to justify, but the same criteria are used to evaluate all plans including those for executives.[41] In practice, this means that the costs of long-term plans are generally excluded altogether and the costs of the short-term annual cash plans are shared 50/50 between shareholders and ratepayers.[42]

Arkansas The Arkansas Commission continues to follow the precedent of its previous orders and generally disallows 50 percent of financially based short-term incentive plans and 100 percent of long-term plans (which include the executive plans). There is some flexibility for considering a utility's particular situation on a case by case basis, but the two larger utilities in Arkansas, Entergy and CenterPoint, are both on formula rate plans and the 50 percent/100 percent disallowance treatment is incorporated in those FRPs, based on their most recent respective rate

41 *See In re: Application of Epcor Water Ariz. Inc*., Ariz. Corp. Comm'n Docket No. WS-01303A-14-0010. *See also*, *In re: Application of UNS Elec. for Establishment of Just and Reasonable Rates* ("UNS 2008 rate case"), Docket No. E-04204A-06-0783, Decision 70360 (Ariz. Corp. Comm'n, May 27, 2008); *In re: Application of UNS Gas* ("UNS Gas 2008 rate case"), Decision 70011 (Ariz. Corp. Comm'n, Nov. 27, 2007); *In re: Application of UNS Gas* ("UNS 2010 GRC"), Docket No. G-04204A-08-057, Decision 71623 (Apr. 14, 2010); *In re: Application of Southwest Gas Corp*. ("Southwest Gas 2006 GRC"), Docket No. G-0155 1A-04-0876, Decision 68487 (Feb. 23, 2006); *In re: Application of Southwest Gas Corp.* ("Southwest Gas 2008 rate case"), Docket No. G-0I55LA-07-0504, Decision 70665 (Ariz. Corp. Comm'n, Dec. 24, 2008); *In re: Application of Ariz. Pub. Svc. Co* ("APS 2008 GRC"), Docket No. E-01345A-08-0172, 50/50 sharing in stipulated settlement; and *In re: Application of Ariz. Pub. Svc. Co* ("APS 2011 GRC"), Docket E-01345A-11-0224, 50/50 sharing in stipulated settlement.

42 *See* e.g., APS 2008 rate case, Decision 70360; Southwest Gas 2008 rate case, Decision 70665; and UNS Gas 2008 rate case, Decision 70011. *See also* Staff's Testimony in the 2016 APS rate case, Docket No. E-01345A-16-0036.

cases, 15-015-U and 15-098-U, in which the Commission specifically expressed this preference.[43]

California: The California Public Utilities Commission (CPUC) examines utility company requests to include incentive compensation in rates on a case by case basis, but the criteria are well established. Generally, incentive compensation expense can be charged to ratepayers only to the extent it is aligned with ratepayer interests. Typically, this treatment results in disallowance of the portion of short-term incentives tied to financial performance.[44] The Commission's consistent practice is to reject recovery of long-term incentives, "because, LTI does not align executives' interests with ratepayer interests."[45] Since the 2010 San Bruno pipeline explosion (and other events including the Aliso Canyon Leak, and the Witch, Guejito and Rice Wildfires which were found to be caused by utilities), legislative and regulatory interest in utility safety has intensified.[46] Consequently, the treatment of incentives is increasingly framed by asking whether the incentives are safety-focused or earnings-focused.

Hawaii <u>Incentive compensation of all types is excluded from rates</u>. Hawaii's longstanding policy to exclude all incentive compensation expense from rates remains firmly in place. The Commission upholds the position stated in Docket No. 6531 that incentives tied to company income and earnings benefit stockholders, not ratepayers. The Commission stated at page 59, "We recognize that incentives encourage cost reductions in some instances. However, we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional

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[43] In Ark. Pub. Svc. Comm'n Docket No. 15-015-U, Order No. 18, pages 18-20, the Commission reversed a settlement treatment which disallowed only 25 percent of Entergy's short-term incentive plan costs, imposing instead a 50 percent disallowance.

[44] Examples of this treatment: *See Application of S. Cal. Edison Co. (U338E) for Authority to, among other things, Increase its Authorized Revenues for Elec. Svc. in 2015, and to reflect that increase in Rates*, Application 13-11-003, Decision 15-11-021 (CPUC, Nov. 5, 2015); *Application of S. Cal. Edison Co. (U338E) for Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Svc. in 2012, and to Reflect That Increase In Rates*, Decision 12-11-051 (CPUC, Nov. 29, 2012); and *Application of Pacific Gas and Elec. Co. for Authority, Among Other Things, to Increase Rates and Charges for Elec. and Gas Svc. Effective on Jan. 1, 2014 (U39M)*, Decision 14-08-032 (CPUC, Aug. 14, 2014).

[45] *See* Decision 15-11-021 at 262.

[46] CPUC's view of incentives in terms of promoting a positive or negative safety culture is discussed at length in Decision 16-06-054 (San Diego Gas & Electric). *See also Application of San Diego Gas & Elec. Co. (U902E) for Authorization to Recover Costs Related to the 2007 S. Cal. Wildfires Recorded in the Wildfire Expense Memo. Account (WEMA)*, Application 15-09-010; *Order Instituting Rulemaking on the Comm'n's Own Motion to Adopt New Safety and Reliability Regulations for Nat. Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms*, Decision 11-06-017 (CPUC, June 9, 2011); and Public Utilities Code Section 706.

compensation. Ratepayers should not be burdened with additional costs for expected levels of service." This treatment is not challenged by the utilities.

Idaho The Commission allows in rates those incentives that benefit customers and exclude those based on financial measures that benefit shareholders. This treatment is the same for incentives at all levels, but executive plans receive closer scrutiny as it is often harder to find customer benefit in these plans. <u>The Commission typically does not include executive compensation in rates</u>.[47]

Kansas For officer level incentives plans, the financially-based portion is borne by the shareholders and the portion supporting operational goals is allowed in rates. Non-officer incentive compensation plans for workers are allowed in rates.[48] The consumer advocacy branch, Citizens' Utility Ratepayer Board (CURB) has consistently recommended applying the same financial/operational criteria to non-officer plans as well. In the current Kansas City Power & Light (KCPL) rate case the company has voluntarily excluded 100 percent of the performance-based plans and 50 percent of the short-term plans with an earnings-per-share qualifier. The Company also removed the earnings-per-share portion of their annual plan for all employees.

Louisiana The LPSC does not allow executive incentive compensation plans to be recovered from ratepayers. Lower level management and employee incentive awards may be included, assuming they are reasonable. The Commission also looks at who benefits, ratepayers or shareholders. <u>Stock based compensation plans at all levels are excluded</u>.

Minnesota Minnesota continues to distinguish between incentive plans tied to financial triggers (such as a threshold ROE) and plans tied to criteria benefitting the ratepayer. Plans based on goals which benefit ratepayers

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[47] The Commission's focus on customer benefit is reflected in the direct testimony of Staff witness Leckie, and in the Final Order in Idaho Power Company Case No. IPC-E-08-10. For earlier examples of the basic policy, *see* Corrected Motion for Approval of Stipulation at 4, section 6(e), *In re: Application of IPC for Authority to Increase its Base Rates and Charges for Elec. Svc. in the State of Idaho* (Mar. 1, 2006) (Case No. IPC-E-05-28); Idaho Power Company Case No. IPC-E-05-28, Order No. 30035 at 4 (May 12, 2006).

[48] This treatment is based on the 2012 KCPL rate case (Docket No. 12-KCPE-764-RTS) in which the short-term plan was split 50:50, and for the long-term incentives, the Commission excluded 100 percent of the portion based on stockholder return and 50 percent of the time-based restricted stock portion of the plan. Time-based plans which vest solely on the passage of time are seen as being neutral and therefore split 50:50 between shareholders and ratepayers.

are generally allowed in rates, but their costs are frequently capped at a percentage of base salaries such as 15 percent or 25 percent.[49] Utilities are usually required to return to ratepayers any portion of incentive pay that was allowed into rates and is not subsequently paid out to employees. Executive and long-term IC measures are frequently more closely aligned with shareholder interests and thus are not usually allowed in rates.[50]

Missouri Missouri's treatment for incentives, generally, is to allow rate recovery for those plans with goals that, if achieved, would lead to improved or more economical service to customers and with the goals known to employees in advance so as to be a real motivational tool. Incentives tied to financial goals such as earnings per share, net income or stock price growth are not allowed. The same criteria are used for executive plans and few are allowed.[51]

Nebraska The Commission still practices the policy that cost should follow benefit and allows in rates the actual amount paid on incentive plans that benefit ratepayers. This treatment is the same for all incentive plans. There are no recent orders on point and no changes are anticipated.[52]

[49] This general policy is demonstrated in the Minnesota Power and Ottertail rate cases: *In re: Application of Minn. Power for Authority to Increase Elec. Svc. Rates in Minn.*, Docket No. E015/GR-09-1151; and *In re: Application of Otter Tail Power Co. for Authority to Increase Rates for Elec. Util. Svc. in Minn*. Docket No. E017/GR-10-239, respectively.

[50] Minnesota's general policy is demonstrated in CenterPoint Energy rate case G-008/GR-13-316 and the Minnesota Power and Ottertail rate cases: Docket Nos. E-002/GR-09-1151 and E-002/GR-10-239, respectively. *See also* Minnesota Power General Rate Cases, Docket No. E-002/GR-05-1428; and *In re: Application of Minn. Power for Authority to Increase Rates for Elec. Svc. in Mont.*, Docket E-015/GR-16-664, Findings of Fact, Conclusions, and Order at 31-34 and 110 (Mar 12, 2018).

[51] *See* e.g., in the Missouri American rate case (WR-2010-0131), not only were plans based on financial goals disallowed, but incentive payments based on customer satisfaction were disallowed due to the unreasonably small sample size used to establish a positive rating (a phone survey of 927 of roughly 450,000 customers). The Commission also removed incentive payments tied to lobbying and charitable activity. In the subsequent Ameren UE rate case, the company did not seek even short-term incentive compensation tied to earnings, providing further indication that staff's practice of disallowing financial performance-based incentives is accepted by the companies. All incentive compensation adjustments were made not only to expense charges, but to construction charges as well. *See also* Kansas City Power and Light and Empire Electric District orders on the Commission's website.

[52] In a 2007 rate case, NG-0041, the Commission disallowed 50 percent, directing that cost should follow benefit and stating, "However, the Commission further finds that the nature of the objectives appear to benefit both ratepayers and shareholders and it would be improper for the ratepayers to bear the full cost of this benefit."

Nevada The Commission excludes 100 percent of the long-term plans and all short-term plan costs directly related to financial performance.[53] Utilities in Nevada generally do not seek to include long-term incentives in rates.

New Mexico The Commission considers this issue on a case by case basis and generally allows recovery through rates of those incentives that are reasonable in amount and tied to metrics that have benefit for customers, such as operational excellence and safety. Incentives that are financially based, for example those tied to stock price performance or earnings, are not allowed in rates. This standard is applied to all levels of utility employees and tends to eliminate the greater portion of executive plans.[54] Executive incentive plans receive more scrutiny as they are more likely to have financial measures. They can also be challenged if the overall percentage is out of line. One major utility in New Mexico no longer includes the compensation of its top five executives in rate applications and some utilities in New Mexico no longer seek recovery of management incentives in rates.

N. Dakota Incentives are treated on a case by case basis, but the Commission's general policy is to allow in rates incentive compensation that is tied to customer benefit and to disallow incentives tied to company financials and corporate benefit. This treatment is the same for all types of incentive plans. Historically, executive incentive compensation is not allowed in rates, and is typically not sought by the company.

Oklahoma The Commission excludes incentive payments tied to financial performance. From a practical perspective this means that all long-term plans are excluded and some portion of the annual short-term cash plan are excluded. The Commission does not determine the precise portion of the annual plans tied to financial measures but instead excludes 50 percent of the annual plans. On occasion, the OCC has excluded 100 percent of the utility's short-term plan when the plan had a financial trigger.[55] One hundred percent of the long-term stock-based plans are excluded.[56] In some instances, the Commission allows gas utilities with formula rates

[53] S*ee,* e.g., *Application of Nev. Power Co. for Authority to Increase its Annual Revenue Requirement for General Rates*, Docket 11-06006, Final Order (Pub. Util. Comm'n of Nev.).
[54] *See* Utah Pub. Svc. Comm'n, Dockets 07-00077-UT, 15-00261-UT, 17-00255-UT.
[55] *See* Oklahoma PUC, Cause Nos. 91-1190 and 200400610.
[56] *See* e.g., Oklahoma PUC: AEP-PSO Cause Nos. PUD 200600285; PUD 200800144; and PUD 201500208; OG&E Cause Nos. PUD 200500151 and PUD 201500273; and OG&E Cause No. PUD 200400610.

plans that share excess earnings with customers to include incentives in rates.

Oregon Short-term, non-officer incentive plans are seen as having some benefit to ratepayers; therefore, 50 percent of merit-based plans are disallowed from rates and 75 percent of plans related to company performance are disallowed.[57] Long-term officer and executive plans are seen as benefitting shareholders and are 100 percent disallowed.[58]

S. Dakota Incentives with stockholder-benefiting financial goals are excluded from rates. This treatment is the same for incentive plans at all levels.[59] Current treatment also includes disallowing both executive and non-executive management incentive compensation. Several utilities have whole incentive programs that hinge on whether or not the company earns a certain return. These financial prerequisites cause the whole plans to be excluded from rates.

Texas At the Texas PUC, the well-established precedent is that incentive payments designed to improve financial performance are excluded.[60] Texas has even disallowed rate case expenses for a utility seeking to include financial-based incentives.[61] In the recent Southwestern Public Service Company ("SPS") rate case, Docket No. 43695, the Texas Public Utility Commission disallowed 100 percent of the short-term incentives directly tied to financial performance measures and 50 percent of the

[57] *See* Oregon PUC: Order 76-601 at 13; Order 77-125 at 10; and Order 87-406 at 42-43.
[58] *See* Oregon PUC: Order 99-033 at 62 and Order 97-171 at 74-76.
[59] This treatment is set forth in EL 15-024, NG 15-005 and EL 14-026 in which the order specifically excluded the amount "tied to the Company's financial results." In Docket No. EL 08-030 the settlement excluded bonuses related to "stockholder-benefitting financial goals." The settlement in Xcel rate case Docket No. EL09-009 removed payments based on financial performance indicators. In the settlement agreement signed July 7, 2010, in the Black Hills Power rate case Docket No. EL09-018 the *Staff Memorandum* states, "The settlement removes financial based incentive payments that were included in the capitalized labor costs for plant. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation."
[60] This has been the consistent policy of the Texas Commission since 2005 when it issued the Final Order in the AEP Texas Central rate case Docket No. 28840., Proposal for Decision at 92-97 and Order at 35, Findings of Fact Nos. 164-170 (Aug. 15, 2005); *See also*, *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Proposal for Decision at 116-121 and Order on Rehearing at 12, Finding of Fact No. 82 (Mar. 4, 2008); *Application of Oncor Elec. Delivery Co. for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 96-100 and Order on Rehearing at 22, Finding of Fact No. 93 (Nov. 30, 2009); and *Application of CenterPoint Elec. Delivery Co. for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 66-67 and Order on Rehearing at 22, Findings of Fact Nos. 81-83 (June 23, 2011).
[61] *See* Docket No. 40295 (the rate case expense docket for Docket No. 39896) where the PUC disallowed $730,734 in Entergy's rate case expense for including Long-Term incentives in its rate application.

remaining incentives because they were indirectly tied to financial performance through an earnings-per-share funding mechanism.[62] The Commission also followed this approach in the recent SWEPCO cases, Docket Nos. 40443 and 46449. <u>Long-term stock incentives are excluded</u>.

At the Railroad Commission of Texas, financial incentives are generally excluded and customer-related incentives are allowed. Examples include: Atmos (GUD No. 9670 Order and Order on Rehearing), Texas Gas Service Company ("TGS") (GUD No. 9988 Final Order), CenterPoint (GUD No. 9902 Final Order), TGS El Paso (GUD No. 10508) and CenterPoint (GUD No. 10106 Final Order). In GUD No. 9670, both the executive and employee plans for Atmos Mid-Tex were found not to be just and reasonable because they, "advanced the interest of shareholders, and [are] driven by Company earnings." None of the costs of these programs were allowed in rates. In more recent Atmos cases, the Commission has allowed the incentives at the operating company level and disallowed the incentives allocated from shared services. This results in about a 50/50 split of the annual incentives. In TGS GUD No. 9988, the RRC found 100 percent of long-term and 90 percent of short-term incentives expense was "unreasonable" because it was related to the financial performance of ONEOK Inc. Ten percent of the short-term plan was allowed in rates because it was based on safety metrics.

Utah The Commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. <u>Equity-based incentive compensation is excluded from rates</u>.[63]

Wyoming Historically, employee incentive compensation plans are evaluated on a case by case basis, distinguishing between employee programs that benefit the ratepayer or the stockholders and requiring the benefitting party to pay. <u>Executive incentive compensation plans are generally excluded from rates</u>.

<u>States that use another approach</u>:

Alaska The Commission in Alaska reviews requests to include incentive compensation in rates to determine if they are reasonable and if they

[62] *See Application of Southwestern Pub. Svc. Co. for Authority to Change Rates*, Docket No. 43695, Order on Rehearing at 5-6 (Feb. 23, 2016).

[63] The Final Order in Docket 09-035-23 follows this general policy as does the Order in Docket 07-35-93. *See also*, Missouri Corp., Docket 97-035-01 at 10-12; U.S. West Commc'ns, Docket 95-049-05.

benefit ratepayers. Short and long-term incentives receive the same treatment. The issue is handled on a case by case basis. In a recent Enstar Natural Gas case, U-16-066, the Commission allowed the Company's short and long-term incentive expense to be included in revenue requirement.

Colorado Executive incentives are excluded from rates and typically no longer sought in company filings. Long-term incentives are not allowed in rates. Recovery of short-term plans is limited to 15 percent of base salary without evaluating plan goals. This treatment was followed in the PSCo Gas rate case in 2018, Proceeding No. 17AL-0363G. No change to this treatment is anticipated at this time.

States where Incentives are not an issue:

Iowa There have been no changes in the treatment of Incentive Compensation. There are no specific treatments in place and the issues is handled on a case by case basis.

Montana Incentive compensation has not been a contested issue in Montana.

Q. What are some examples of commissions that use a *sharing* approach that you mentioned earlier?

A. In the survey of western states, we identified several states that use a sharing approach, some of which include:

Arkansas: The Commission's policy is to disallow 50 percent of the short-term incentive plan costs in cases where the company's incentive compensation plans are based in part on financial performance measures.[64]

[64] *See* Ark. Pub. Svc. Comm'n, Docket No. 13-028-U, Order No. 21 at 54; and Docket No. 15-011-U, Order No. 10 at 22 [citing prior dockets: Docket No. 04-121-U (Order No. 16 at 23-25); Docket No. 04-176-U (Order No. 6 at 38-40); Docket No. 06-101-U (Order No. 10 at 62-69, which order as related to incentive compensation was upheld on appeal at 104 Ark. App. 147, 289 S.W.3d 513 (2008))].

Arizona: The Arizona commission on numerous occasions has shared the cost of annual incentive plans on a 50 percent – 50 percent split between shareholders and ratepayers.[65]

Kansas: The Kansas commission disallows 100 percent of plans based on financial measures and 50 percent for plans using a balance of financial and operational measures.[66]

Oklahoma: The Commission excludes incentive payments tied to financial performance. The Commission does not determine the precise portion of the annual plans tied to financial measures but instead excludes 50 percent of the annual plan costs.[67]

Oregon: The Oregon commission sees short-term, non-officer incentive plans as having some benefit to ratepayers; therefore, 50 percent of merit-based plans (those based on operational measures) are disallowed and 75 percent of plans related to company performance (i.e., financial measures) are disallowed.[68]

Q. Are you aware of the treatment of incentives in any other states?

A. Yes. In conjunction with a recent Indiana & Michigan Power rate case we were involved with in Indiana, we surveyed four states in close proximity to Indiana: Illinois, Kentucky, Michigan and Wisconsin. Although most regulatory commission's decisions are

[65] *See* e.g., Epcor Water, Docket No. WS-01303A-14-0010. *See also*, UNS 2008 GRC, Decision 70360; UNS Gas 2008 GRC, Decision 70011; UNS 2010 GRC, Decision 71623; Southwest Gas 2006 GRC, Decision 68487; and Southwest Gas 2008 GRC, Decision 70665; APS 2008 GRC, Docket No. E-01345A-08-0172, 50/50 sharing in stipulated settlement; and APS 2011 GRC, Docket No. E-01345A-11-0224, 50/50 sharing in stipulated settlement.
[66] *See* 2012 KCPL GRC, Cause No. 12-KCPE-764-RTS, in which short-term incentive costs were allocated 50 percent.
[67] As discussed above, for electric utilities such as AEP, the Oklahoma commission has used a 50 percent sharing allocation for many years, in numerous cases. *See,* e.g., OCC Final Order No. 672864 at 57, in AEP-PSO's last rate case, Cause No. PUD 201700151. For gas utilities that use formula rates with an earnings-sharing mechanism, financial based incentives have been allowed because the increased earnings they generate are shared with customers.
[68] *See* Oregon PUC: Order 76-601 at 13; Order 77-125 at 10; and Order 87-406 at 42-43.

made on a case-by-case review of the evidence presented in each rate case, the general rule in these states is that financial-based incentives are not included in rates. The regulatory treatment in these states is set forth below:

Illinois: The general approach of the Illinois Commerce Commission has been that incentives based on financial goals are not allowed while those with operational goals are allowed in rates.[69] These criteria have been consistently applied by the Commission to short-term, long-term and executive incentive compensation. Long-term incentives are more often financially based and therefore more often disallowed. This treatment is the Commission's general practice, but it is also codified in the statute governing the formula rate plans for the state's two largest utilities (Ameren Illinois and Commonwealth Edison). Statute §220 ILCS 5/16-108.5 c) subsection 4(A) states:

> Recovery of incentive compensation expense that is based on the achievement of operational metrics, including metrics related to budget controls, outage duration and frequency, safety, customer service, efficiency and productivity, and environmental compliance. Incentive compensation expense that is based on net income or an affiliate's earnings per share shall not be recoverable under the performance-based formula rate.

Kentucky: Any incentive compensation related to financial metrics is disallowed 100 percent. This treatment is applied to short-term, long-term and executive incentives. This treatment is not prescribed by regulation or statue, but has been the longstanding practice of the Commission. This treatment is set forth in the recent Kentucky American rate case 18-00358.[70] In this case, 100 percent of the long-term incentives were

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[69] *See* Commonwealth Edison, Docket No. 05-0597 at 95-97 (affirmed on appeal); North Shore Gas/Peoples Gas, Docket Nos. 09-0166 and 09-0167, (affirmed on appeal); and Illinois-American Water Co., Order No. 16-0093 at 37.
[70] *See Electronic Application of Kentucky-American Water Co. for an Adjustment of Rates*, Kentucky Pub. Svc. Comm'n Case No. 18-00358, Order 01 at 41-44 (June 26, 2019). *See also*, *Application of Kentucky Power Co. for a*

disallowed while 50 percent of the short-term incentives were allowed. Even though the short-term plan had a funding mechanism based on earnings per share, the plan's performance measures were deemed 50 percent financial and 50 percent non-financial. There have been no recent changes to this treatment.

Michigan: Incentive compensation based on financial metrics are excluded from rates. Incentives with non-financial metrics which have a demonstrable benefit to ratepayers are allowed in rates. This treatment is used for all incentive compensation and can produce a different result for short-term verses long-term and executive plans which are often stock-based plans which are not included in rates. There are no statues requiring this treatment, but it is the Commission's well-established policy based on consistent precedent. This treatment is set forth recently in Consumers Energy Company Electric Rate Case U-18322 and DTE Electric Rate Case U-20162.[71]

Wisconsin: Incentive compensation based on financial metrics are excluded from rates, as the commission has found that such plans do not reasonably provide benefits to ratepayers when tied to financial metrics.[72] In the Wisconsin Public Service 2013 rate case, the commission stated:

> The Commission is not persuaded it should change its practice of excluding incentive compensation from revenue requirements of the major investor-owned utilities in Wisconsin. WPSC has not demonstrated that the plans provide substantial ratepayer benefit with enough quantified permanent savings to ratepayers to warrant inclusion of the costs in revenue requirement. With the majority of executive incentive performance measures still ***tied to meeting earnings per share criteria***, and the non-

General Adjustment of its Rates for Elec. Svc, Kentucky Pub. Svc. Comm'n Case No. 14-00396, Order at 24-26 (Sept. 16, 2015).

[71] In the U-20162 Order, the Commission cites Staff's Initial Brief (at 67-68) in which Staff lists 11 prior cases in which the Commission disallowed financially-based incentive compensation which does not benefit ratepayers.

[72] *See Application of Northern States Power Co. – Wisconsin for Authority to Adjust Elec. And Nat. Gas Rates*, Docket 4220-UR-123, Final Decision at 16 (Dec. 21, 2017).

> executive incentive performance measures that weigh heavily on measures tied to the shareholders benefit, ***the Commission finds it is reasonable to exclude all incentive compensation costs from the revenue requirement***.[73]

Q. Are there examples among these states in which incentive compensation costs were disallowed specifically as a result of a financial-based funding mechanism?

A. Yes. In Illinois, in a Commonwealth Edison case, Docket No. 05-0597, at pages 96-97, the commission order states:

> Turning our attention to the individual parts of the incentive compensation structure, we agree with Staff and the AG that the ***earnings per share ("EPS") funding measure***, which constitutes fifty percent of overall plan funding, should not be allowed to be recovered through rates. As the name of the ***funding measure*** suggests, the primary beneficiaries of increased earnings per share are shareholders, not ratepayers. (Emphasis added).

On appeal, the Appellate Court affirmed the commission's order and made the following statement at page 12 of its decision:

> [p]recedent exists for apportioning employee compensation costs between equity holders and ratepayers where an employee's duties only partially benefit ratepayers. . . Moreover, the notion that an earnings-per-share-based employee incentive plan provides benefits to shareholders is hardly a controversial proposition.

Q. In your experience, when regulators exclude the portion of a utility's incentive plan tied to financial performance measures, does the utility stop offering incentive compensation to help achieve its financial goals?

No. Even though regulators generally disallow incentive compensation tied to financial performance for ratemaking purposes, utilities continue to include financial performance

[73] *Application of Wisconsin Pub. Svc. Corp. for Authority to Adjust Elec. And Nat. Gas Rates*, Docket 6690-UR-122, Final Decision at 24 (Dec. 18, 2013) (emphasis added).

as a key component of their plans. In my opinion, utilities continue to tie incentive payments to financial performance because by doing so they achieve the primary objective of the incentive plans: to increase corporate earnings and, thereby, earnings per share (EPS). However, since the utility retains the increased earnings these plans help achieve, payments for these plans should be made from a portion of the increased earnings. These plans need not be subsidized by ratepayers. Recovery of plan costs through rates ***is not necessary to attract a talented workforce*** because the Company has other means of cost recovery—through the increased earnings generated by the plan.

Q. What is the general rationale for excluding incentive compensation tied to financial performance?

A. In most jurisdictions, the cost of incentive plans which are tied to financial performance measures are excluded for ratemaking purposes. When the costs associated with these plans are excluded, the ***primary*** rationale is that financially-based incentives benefit shareholders more than they do ratepayers. Other rationale used by the regulators is generally based on one or more of the following reasons:

(1) **Payment is uncertain.** Often, payment of incentive compensation is conditioned upon meeting some predetermined financial goal such as achieving a certain increase in earnings, reaching a targeted stock price or meeting budget objectives. If the predetermined goals are not met, the incentive payment is not made, or payment is made at some lesser amount. Therefore, one cannot know from year to year what the level of the payment may be or whether the payment will be made at all. It is generally considered inappropriate to set rates to recover a tentative level of expense.[74]

[74] PSO's experience with its 2008 rate case proceeding, in Oklahoma PUD 2008-00144, is a good example of this problem. In 2009, AEP's below target EPS reduced the funding available for incentive compensation payments by 76.9 percent. Although in the Company's 2008 rate case, the Commission had included more than $4 million in rates for incentives, the Company chose not to use all of that money to pay incentives but instead retained some of those funds for its shareholders to help bolster the Company's lower earnings that year.

(2) **Many of the factors that significantly impact earnings are outside the control of most company employees and have limited value to customers.** For example, an unusually hot summer can easily trigger an incentive payment based on company earnings for an electric utility, as a cold winter can for a gas utility. Obviously, weather conditions are outside the control of utility employees and customers receive no benefit from the higher utility bills that result from an unusually hot or cold weather. Similarly, company earnings may increase, thus triggering incentive payments, as a result of customer growth, which commonly occurs without significant influence from company personnel. In fairness, since shareholders enjoy the benefits of customer growth between rate cases, shareholders should also bear the cost of any incentive payments such growth may trigger. Finally, utility earnings may increase substantially if the utility is able to successfully argue for a higher ROE in a rate case proceeding. Utility efforts to maximize ROE in a rate proceeding, however, have little to do with improving overall employee performance across the company. If utility employees gear their efforts toward securing an *unreasonably* high ROE in a rate proceeding, the incentive mechanism actually would work to the detriment of the utility customers.

(3) **Earnings-based incentive plans can discourage conservation.** When incentive payments are based on earnings, employees may not support conservation programs designed to reduce usage if they perceive these programs could adversely impact incentive payment levels. To the extent that earnings-based incentive plans discourage conservation and demand-side management programs, these plans do not serve the public interest. The growing focus on energy efficiency at both the national and state level renders this point especially important.

(4) **The utility and its stockholders assume none of the financial risks associated with incentive payments.** Ratepayers assume the risk that the utility will instead retain the amounts collected through rates for incentive payments whenever targeted increases are not reached. Employees assume the risk that the incentive payments will not be made in a given year. The utility and its stockholders, however, assume no risk associated with these payments. Instead, the company's only responsibility is to decide who gets the money, the stockholders or the employees.[75]

(5) **Incentive payments based on financial performance measures should be made out of increased earnings.** Whatever the targets or goals may be that trigger an incentive payment, when the plan is based in whole or in part on financial performance measures the company always obtains a financial benefit from achieving these objectives. This financial benefit should provide ample funds from which to make the payment. If not, the incentive plan was poorly

[75] *Id*.

conceived in the first place. As such, employees should be compensated out of the increased earnings, and not through rates.

(6) Incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition. When utilities are allowed to embed amounts for incentive payments in rates, that money is available to the utility not only to pay the incentive payment when financial performance goals are met but also to supplement earnings in those years when the company does not perform well. In those years when financial performance measures are met, the increased earnings of the company provide ample additional funds from which to make the incentive payments to employees, and the incentive payment amount embedded in rates is not needed. In those years when financial performance measures are not met and the incentive payments are not made, the amount embedded in rates for incentive payments acts as a financial hedge to shelter the poor financial performance of the company.

Q. Utilities often assert that incentive plans should be included in rates because they are part of a total compensation package and are comparable with the compensation paid by other utilities. Do you agree?

A. No. The rationale typically given for including incentive pay in rates is that incentive pay should be included in rates because it is needed to attract and retain qualified personnel. However, the argument is problematic. First, it misses the point. The question for regulators is not about what the Company should pay; the question for regulators is what ratepayers should pay. The utility is free to offer whatever compensation package it deems appropriate to offer its employees, but most regulatory commissions agree that ratepayers should not pay the costs of plans designed to increase corporate earnings. Also, because incentive pay related to financial performance is generally disallowed, most of the utilities that compete with for talent generally do not recover all of their incentive compensation in rates. Therefore, a utility is not put at a competitive disadvantage when its incentive pay is similarly adjusted.

The Oklahoma commission addressed similar arguments that a utility's incentive compensation was reasonable, comparable to other utilities, beneficial to ratepayers, and part of a total compensation package in AEP/PSO's 2008 rate case, Cause No. PUD 200800144, in which the Commission disallowed 50% of the annual incentive plan:

> The Commission finds that ***although there is no evidence to conclude PSO's and AEPSC's overall salary levels are excessive***, that the recommendation of the AG and Staff to disallow 50% of PSO's and AEPSC's incentive compensation should be adopted. ***Incentive compensation benefits both shareholders and ratepayers equally***, by encouraging the attainment of goals that provide good customer service and increase the earnings of the shareholders.[76]

Another common problem with the Company's "total compensation package" argument is that when an incentive payment is based on achieving financial performance goals there should be a financial benefit to the company that comes from achieving these goals. This financial benefit should provide ample additional funds from which to make the incentive payments. If not, the plan was poorly conceived. Thus, a utility is not placed at a competitive disadvantage when incentive payments tied to financial performance are not collected through rates, because the funding for these payments should come out of the additional earnings the incentive plans help achieve.

Q. Utilities also claim incentive compensation costs are necessary to attract and retain qualified personnel to provide safe and reliable service. Do you agree?

A. No. Utilities often claim their incentive compensation plans are necessary attracting for talent to provide safe and reliable service. The problem with this assertion is that it is not actually true. Much of the electricity in this country is provided by municipal electric

[76] *See* OCC Order in Cause No. PUD 2008-00144.

providers that do not pay short-term incentives, yet they are able to attract talent sufficient to deliver safe and reliable service.[77] Electric cooperatives also provide a substantial amount of the electricity used in this country but many do so without the use of short-term incentives.[78] Likewise, many state-run electric systems also provide electric service without the use of short-term incentives,[79] as do some federally-owned utilities.[80] So, it is inaccurate to say that incentives are ***necessary*** for the provision of electric service.

The other problem with this argument is that it does nothing to explain why incentive pay should be included in rates. Virtually all utilities have the same need to attract qualified employees, but most of these other utilities are ***not recovering*** the full amount of their incentive pay in rates, particularly when incentive pay is tied to financial performance.

Q. Are you recommending that the Company eliminate its short-term incentives?

A. No. The question for ratemaking purposes is not whether the utility should offer short-term incentives to its employees; the question is, who should pay for them. My point is that the metrics of many incentive compensation plans (like PSE's plan in this case) are primarily designed to increase shareholder wealth rather than to enhance the provision of safe and reliable electric service. The consensus view is that financial-based incentives benefit the shareholders more than they do the ratepayers, and, as a result, should be paid for by the shareholders. This point was addressed recently by the Wisconsin commission:

[77] *See,* e.g., OCC Cause No. PUD 2018-00140, OG&E response to OIEC 9-8.
[78] *Id*.
[79] *Id*.
[80] *Id*.

> [T]he Commission is not persuaded by NSPW's arguments that its overall compensation without the AIP would fall below market rates. The Commission is also not persuaded by NSPW's argument that recovery of the AIP expense from ratepayers is required in order for NSPW to attract and compete for employees. NSPW provided no evidence of any unsuccessful recruitments or other examples of any difficulty in hiring talented employees because NSPW is not recovering its AIP payments in rates. *NSPW's management is not prohibited from paying a portion of its overall 2018 employee compensation in the form of incentives*. However, the amount of payroll expense authorized for recovery is limited to what the Commission has determined to be reasonable in this case.

Q. What are you recommending with respect to the Company's incentive expense?

A. The Company's plan is ***strongly tied*** to financial performance measures which include: an earnings trigger ***and*** an earnings performance funding metric. Moreover, the award payouts increase to a greater extent with increased earnings than they do with operational metrics.[81] Based on these factors, ***it would be reasonable for the Commission to disallow 50 percent,*** or more, of the annual incentive plan costs.

Although a greater disallowance could be justified, I am recommending instead that the Commission adopt a ***50 percent – 50 percent sharing approach*** which allocates the annual incentive plan costs evenly between shareholders and ratepayers. A 50 percent – 50 percent sharing approach is a reasonable approach that recognizes the Company's plan is based on both financial and operational performance measures, and that it benefits both shareholders and ratepayers. My adjustment removes 50 percent of the annual incentive plan costs included in pro forma operating expense in the Washington jurisdiction. The calculations supporting this adjustment are set forth at Exhibits MEG-3

[81] See the Short-Term Incentive Plan table at the beginning of this section of testimony.

and MEG-4.

Adjustment to Remove 50% of Annual Incentive Costs

Adjustment to Remove 50% of Electric O&M Expense	$(3,781,194)[82]
Adjustment to Remove 50% of Gas O&M Expense	$(1,546,627)[83]

V. TAX CUTS AND JOBS ACT ISSUES

Q. Please describe your experience with TCJA ratemaking issues.

A. I have testified and/or consulted in numerous cases involving implementation of the TCJA with respect to the following utilities:

a. Avista Corporation d/b/a Avista Utilities ("Avista"),
b. Atmos Energy Corp., Mid-Tex Division ("Atmos Mid-Tex"),
c. Atmos Pipeline—Texas ("APT"),
d. CenterPoint Energy Houston Electric ("CEHE"),
e. El Paso Electric Company ("EPE"),
f. Empire District Electric Company ("Empire"),
g. Nevada Power Company ("NPC"),
h. Oklahoma Gas & Electric Company ("OG&E"),
i. Oncor Electric Company ("Oncor"),
j. Public Service Company of Oklahoma ("AEP-PSO"),
k. Sierra Pacific Power Company ("SPPC"),
l. Southwest Gas ("SWG"),
m. Southwestern Public Service Company ("SPS"),
n. Texas Gas Service ("TGS"),
o. Aqua Utilities Inc. ("Aqua Texas"),
p. CenterPoint Energy Houston, LLC ("CenterPoint Energy")

[82] *See* Garrett, Exh. MEG-3 at 4.
[83] *See* Garrett, Exh. MEG-4 at 4.

A. TCJA Treatment Proposed by PSE

Q. Please describe the Company's proposal with respect to the TCJA?

A. The TCJA reduced tax rates for corporations, including regulated utilities such as PSE, from 35 percent to 21 percent effective January 1, 2018. This tax reduction generated two sources of savings for ratepayers: (1) the tax rate reduction from 35 percent to 21 percent produced a lower annual tax expense to be included in rates, and (2) the tax rate reduction produced excess accumulated deferred federal income taxes ("ADIT") that was collected from ratepayers at the 35 percent rate but will be remitted to the IRS at the lower 21 percent rate. This excess ADIT ("EDIT") was collected from ratepayers and must be returned to ratepayers. The EDIT is segregated into two categories: (i) protected EDIT, mainly related to utility plant, that must be returned (amortized) to ratepayers, but on a schedule that is no faster than the *Average Rate Assumption Method* prescribed in the TCJA; and (2) unprotected EDIT, not subject to the normalization rules, that can be returned to ratepayers over any time period set forth by the commission.

The issues related to the TCJA were addressed in PSE's recent Expedited Rate Filing (ERF), Docket Numbers UE-180899 and UG-180900 through a Settlement Stipulation and Agreements ("Settlement").[84] The Settlement provided for a rider to begin the prospective refund of the protected EDIT to customers, and for the refund liability of the protected EDIT for the period January 1, 2018, through February 2019 to

[84] *See* Settlement Stipulation and Agreement ("Settlement"), *WUTC v. Puget Sound Energy* (Jan. 30, 2019) (Dockets UE-180899 and UG-180900).

be decided in PSE's next general rate case.[85] The Commission order modified the settlement to provide that the over-collection of income tax expense from January 1, 2018, through February 28, 2019, be refunded to customers beginning May 1, 2019. [86,87] The disposition of the protected EDIT amortization was left to be decided in this case.

In its application, PSE is continuing to base its income tax expense calculation on the reduced 21 percent corporate income tax rate and will continue to refund the protected EDIT using the required ARAM methodology. With respect to the unprotected EDIT, PSE is proposing to amortize the account balance over a four-year period. However, with respect to the amortization of the protected ADIT related to the period January 1, 2018, through February 28, 2019, the Company is improperly transferring these tax benefits to its shareholders by amortizing the amounts over-collected from ratepayers as current income to PSE.[88]

Q. Do you agree with the Company's proposal to retain the protected EDIT for the January 1, 2018, through February 28, 2019 period?

A. No. I do not agree with the Company's decision to begin amortizing the protected ADIT account balance immediately as income between rate cases, thereby effectively transferring this portion of ratepayer tax benefits to its shareholders. The protected EDIT account represents taxes over-collected from ratepayers which should be held by the Company in a segregated *regulatory liability* account. To be clear, these funds are ***ratepayer funds*** that must ultimately be returned to ratepayers.

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[85] *See* Settlement at 14.
[86] *See* Settlement at 15.
[87] *See WUTC v. Puget Sound Energy*, Dockets UE-180899 and UG-180900, Final Order 05 at 1-2 (Feb. 21, 2019).
[88] *See* Prefiled Direct Testimony of Matthew R. Marcelia, Exh. MRM-1T at 30:4-11.

These funds are not a convenient source of income for PSE to amortize into income for the benefit of its shareholders during the interim period between rate cases. Accumulated deferred income taxes are sometimes described as an interest free loan from the federal government. If fact, for a regulated utility, these funds are collected from ratepayers, so the ADIT balances represent a loan from the ratepayers to the utility. If a utility no longer has the tax liability those funds were provided for, then those funds should be returned to the ratepayers.

With the numerous other utilities with which I have worked on these issues, only NV Energy even attempted to redirect these ratepayer funds to shareholders, but failed. In the filings presented by PSE, I have found no legitimate legal nor ratemaking theory articulated that would allow for the redirection of these funds to shareholders.

Q. How has the Commission in this state addressed the TCJA issues?

A. This Commission has been exceeding clear from the beginning that all of the savings from the TCJA must go to ratepayers. On January 3, 2018, the Commission issued Bench Request No. 1 ("BR-1") requiring utilities to provide the impacts of the TCJA on the revenue requirement and the proposed ratemaking treatment of those impacts. On January 8, 2018, the Commission issued a press release that it had "directed regulated utilities to track federal tax savings resulting from the federal Tax Cuts and Jobs Act to ensure those savings will benefit utility customers."[89] On April 26, 2018, the Commission approved an agreement between Staff and Avista that would return all of the protected EDIT of

[89] *See WUTC v. Cascade Nat. Gas Corp*. Docket No. UG-170929, Order 06 ¶ 39 (July 20, 2018).

Avista, as of December 31, 2018, back to ratepayers.[90] On July 20, 2018, the Commission ordered Cascade Natural Gas Corporation to return to ratepayers all of the protected EDIT amortizations from January 1, 2018, forward.[91]

Q. Why is the Avista order particularly important?

A. The Avista decision completely undermines PSE assertions that any deferral of protected EDIT would result in a normalization violation of the tax rules. The Avista order was issued in April of 2018, well after the January 1, 2017, start date for protected EDIT reversals. The fact that Avista has not reported a normalization violation as a result of deferring its protected EDIT reversals to be amortized to ratepayers at a later date to coincide with Commission instructions, should give the Commission a level of comfort that PSE's interpretation of the normalization rule application to protected EDIT amortization for ratemaking purposes is not accurate.

Q. Why is the Cascade case important?

A. Cascade, like PSE, attempted to divert some of the TCJA benefits to its shareholders. Specifically, Cascade proposed treating the protected EDIT amortization from January 1, 2018, through July 31, 2018, called the *Interim Period*, as a period cost, which, in effect, passed the EDIT benefits to the Company and its shareholders rather than to ratepayers.[92] The Cascade decision is important for two reasons. First, it is an example of another utility that attempted and failed to retain for itself the protected EDIT in the interim

[90] *See WUTC v. Avista Corp*. Dockets UE-170485 and UG-170486, Order 07 ¶ 21 (Apr. 26, 2018).
[91] *See WUTC v. Cascade Natural Gas Corp.*, Docket UG-170929, Order 06 ¶ 39 (July 20, 2018).
[92] *Id*. ¶ 17.

period before the amortization could be included in rates. Second, it is another example of a utility in Washington that was required to defer the reversals of protected EDIT for a future amortization to ratepayers – without any normalization rule violation. The Cascade decision is also important because of the strong language included in the Commission's regarding TCJA benefits.

> As the Commission stated in its final order in another recent general rate proceeding, the commission has indicated its expectation that customers should realize the benefits of the reduced tax rate following the enactment of the TCJA through refunds or rate credits. Indeed, on January 8, 2018, the Commission issued a press release stating that it had "directed regulated companies to track federal tax savings resulting from the federal Tax Cuts and Jobs Act to ensure those savings will benefit utility customers." The press release further advised that "utilities are on notice that we expect customers will reap the benefits."[93]

Q. Do you agree with the argument of Company witness, Matthew R. Marcelia, that the delay in the refund of the protected EDIT would be inconsistent with the normalization requirement in the TCJA?

A. No. Mr. Marcelia is incorrect in his conclusions regarding the protected EDIT amortization. As I explain later in this testimony, utilities across the country have complied with both the normalization rules and commission requirements to preserve all of the EDIT amortization benefits for ratepayers by merely deferring the EDIT amortizations in a regulatory liability account to be refunded to ratepayers at the first available rate-setting proceeding. I know of no utility that has successfully argued to retain the benefits of protected EDIT amortization for shareholders. In my experience, all of the protected EDIT is being returned to ratepayers, generally after some deferral

[93] *Id*. ¶ 39.

period. Moreover, I have not heard of any utility incurring a normalization violation from following this approach.

Q. Have you reviewed the IRS Private Letter Rulings mentioned in Mr. Marcelia's testimony?

A. Yes. On pages 17 through 23 of his testimony, Mr. Marcelia refers to three Private Letter Rulings (PLRs) in support of his recommendation that the protected EDIT balance on PSE's books should be amortized to the benefit of shareholders rather than preserved for ratepayers.[94] However, none of the PLRs Mr. Marcelia refers to actually address the issue currently before the Commission—the appropriate ratemaking treatment of the protected EDIT balance. Mr. Marcelia opines, based upon prior tax law and factually dissimilar circumstances, that the IRS *may* interpret the normalization rules in a way that *requires* PSE to amortize protected EDIT balances to the benefit of shareholders, rather than preserving the balances for the benefit of ratepayers. I do not agree with his conclusion that this is the treatment the rules *require* for protected EDIT balances under the TCJA. For these reasons, I do not find the analysis of these PLRs particularly relevant or helpful.

Private letter rulings are issued in response to very specific tax queries presented by a taxpayer under the law in effect at that time. PLRs are always directed *only* to the taxpayer requested it, and pursuant to Section 6110(k)(3) of the Code, PLRs may not be used or cited as precedent. Only *one* of the three PLRs that Mr. Marcelia cites was actually issued to PSE. That PLR, issued in 2008, dealt with PSE's inconsistent use of the

[94] *See* Marcelia, Exh. MRM-3, PLR-8920025 dated February 15, 1989; Exh. MRM-4, PLR-108661-07 dated February 15, 2008; Exh. MRM-5, PLR-201828010, issued July 13, 2018.

"average of monthly averages (AMA)" to calculate gross rate base, while using a different method to calculate its accumulated deferred federal income tax. Thus, the issues addressed in PSE's 2008 PLR are far afield from the issue at hand—the appropriate treatment of the Company's protected EDIT balances that exist as the result of the TCJA reducing the federal income tax rate from 35 percent to 21 percent.

Similarly, the two other PLRs mentioned by Mr. Marcelia are not on point. They address tax questions raised by other taxpayers which are not specifically related to the treatment of protected EDIT balances under the TCJA. In the discussion below, I address several of cases involving recent proceedings in which regulatory commissions have addressed specifically the impact of the 2017 TCJA on protected EDIT. In these proceedings, TCJA provisions and the IRS normalization rules have been interpreted in a manner that allows the utility to defer protected EDIT and return it to ratepayers without giving rise to any tax normalization violation.

Q. What are your recommendations with respect to the amortization of the 2018 protected EDIT?

A. I recommend that the Commission require PSE to restore the protected EDIT reversals (amortizations) from January 2018 through February 2019 to a regulatory liability account to be returned to ratepayers over a two-year period. Now that the ARAM reversal period has passed for these amortizations (January 2018 through February 2019), the funds can now be treated as ***unprotected*** EDIT and can be returned to ratepayers over any period the Commission determines appropriate.

Q. What is the amount of the protected EDIT that was amortized during the period from January 1, 2018, through February 28, 2019?

A. The protected EDIT amortized to the shareholders during that period total $26,928,588 for the electric utility[95] and $7,045,709 for the gas utility.[96]

Q. What adjustments do you recommend for the ARAM amortization the Company credited to shareholders?

A. I recommend that the regulatory liability for the EDIT amounts passed through to shareholders be restored, and those balances be amortized to ratepayers over a two-year period. I also recommend that a rider be used to true up the amortization to ensure that all the EDIT ARAM amortization is credited to ratepayers in a manner that complies with the TCJA.

Q. Are you aware of any other utility that has successfully attempted to amortize excess protected ADIT to income based on normalization requirements – effectively passing ratepayer money to shareholders – as PSE is attempting to do?

A. No. The utilities that I have worked with on TCJA issues have segregated the protected ADFIT into a regulatory liability account for commission approval to amortize the balance into rates. The only exception is in Nevada, where NV Energy based its arguments on commission rules specific to that state. The Nevada commission rejected the utility's arguments and ordered that the protected amortization be returned to

[95] *See* Garrett, Exh. MEG-6, PSE Response to WUTC Staff Data Request No. 67: $23,516,910 + $21,106,142*(31+28)/365 = $26,928,588.

[96] *See* Garrett, Exh. MEG-6, PSE Response to WUTC Staff Data Request No. 67: $6,272,059 + $4,786,138*(31+28)/365 = $7,045,709.

ratepayers. No other utility has even attempted to redirect the protected excess ADIT to shareholders rather than to ratepayers, from whom it was collected. The approaches used by of some of these utilities – in the cases where I have provided testimony – are as follows:

Oncor Electric Delivery Company, LLC ("Oncor"). In its application for authority to decrease rates based on the TCJA, Oncor proposed to reduce its rates to reflect the full impact of the TCJA, including reduction of the FIT rate to 21 percent, amortization of protected and net unprotected excess ADFIT, and a refund of the FIT expense amounts in excess of the 21% rate that have been collected and deferred since January 1, 2018.[97]

CenterPoint Energy Houston, LLC ("CenterPoint Energy") provided revenue requirement schedules in its Distribution Cost Recovery Factor (DCRF) case that included the impacts of the TCJA corporate tax rate change from 35 percent to 21 percent on the Company's requested rate increase. The results of including the tax rate impacts reduced the Company's requested rate increase by $39,024,595.[98] The Company's quantification of the TCJA impacts included only the impacts of the corporate federal income tax rate change from 35 percent to 21 percent. It did not include in the current case any amortization of the excess protected or unprotected EDIT balances related to the TCJA impacts. CenterPoint segregated those excess EDIT balances into regulatory liability accounts that it will amortize into rates in its scheduled 2019 rate case proceeding. It did not attempt to redirect any of the excess EDIT to shareholders; it is

[97] *See* Docket No. 18-48325.
[98] *Id.*

only requesting to wait one year to start giving the money back to ratepayers, citing normalization concerns.[99]

Oklahoma Gas and Electric ("OG&E"). In its rate case, OG&E included the full impacts of the TCJA, including the rate change from 35 percent to 21 percent and the amortizations of both protected and unprotected EDIT deferred from January 1, 2018, forward. OG&E is including in rates its calculated amortization for protected EDIT using the ARAM method. It will flow any over or under recovery of the actual EDIT amortization to ratepayers through a rider mechanism. This will protect the utility and its ratepayers from any tax normalization inconsistencies.[100] OG&E also accrued a regulatory liability for the tax rate change benefits from January 2018 forward in accordance with the Oklahoma Commission's TCJA order. OG&E is proposing to flow back to ratepayers the tax benefits held in the regulatory liability account through a rider mechanism.

American Electric Power – Public Service Company of Oklahoma ("AEP-PSO"). AEP-PSO included the savings from the tax rate reduction to 21 percent in its 2017 rate case, with new rates going into effect in March 2018. In AEP-PSO's tax case, filed in February of 2018, the Company requested to amortize deferred protected EDIT and unprotected EDIT to ratepayers through a rider mechanism with an annual true-up.[101]

[99] *See* Texas PUC Docket No. 48226.
[100] *See* Oklahoma Cause No. PUD 201400496.
[101] *See* Responsive Testimony of Steven L. Fate at 306 in Oklahoma Cause No. PUD 201700572. AEP-PSO's request is to essentially amortize the protected ADFIT back to ratepayers through a rider mechanism with true-up and use the unprotected deferred taxes to pay-off the stranded asset that remains from the early retirement of its Northeastern 4 Coal Unit.

AEP-PSO says that this approach will allow the Company to avoid any normalization violations.[102]

Southwestern Public Service Company ("SPS"). In its rate case, SPS quantified the TCJA impacts on its rate case application. The Company's quantification of TCJA impacts included adjustments for: (1) the corporate income tax rate change from 35 percent to 21 percent and (2) the amortization of both protected and non-protected EDIT.[103] SPS did not include a refund of the deferred TCJA impacts from the January 25, 2018, effective date of the Commission's Amended Accounting Order forward because SPS's rates in that case will *relate-back* to January 23, 2018, a date which precedes the date of the order in that case, which means ratepayers will receive 100 percent of the TCJA benefits.[104]

*Southwest Gas Corporation ("*SWG"). In its 2018 Nevada rate case, Docket No. 18-05031, SWG proposed to include in its new base rates, that were to start in 2019, the first-year amortization of the protected EDIT using the ARAM method. However, when these new SWG rates go into effect in 2019, both the 2018 protect EDIT amortization and the 2019 protected EDIT amortizations will be available to amortize in 2019. The IRS normalization rules only require that the amortization of protected EDIT be no faster than ARAM.[105] The amortization can certainly be slower than ARAM. This is what allows the

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[102] *See* Responsive Testimony of Randy Hamlett at 3:3-11, Oklahoma Cause No. PUD 201700572.
[103] *See* Freitas Supplemental Direct Testimony at 13, Texas PUC, Docket No. 47527.
[104] *See* Koch Supplemental Direct Testimony at 17, Texas PUC, Docket No. 47527.
[105] The normalization rules require that protected EDIT be amortized no more rapidly than the ARAM approach: "d) Normalization Requirements— (1) IN GENERAL—A normalization method of accounting shall not be treated as being used with respect to any public utility property for purposes of section 167 or 168 of the Internal Revenue Code of 1986 if the taxpayer, in computing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, reduces the excess tax reserve more rapidly or to a greater extent than such reserve would be reduced under the average rate assumption method." Pub. L. 115-97 Sec. 13001(d) (emphasis added).

utility to start the amortization of protected EDIT in 2019, when, under ARAM, it could have started in 2018. In short, this means the 2018 ARAM amortization is available to return to ratepayers in 2019, along with the 2019 amortization.

The point of discussion these cases is that all of these companies found ways to defer protected EDIT and return it to ratepayers without any normalization rule violations.

Q. If the Commission were to order that the protected EDIT amortization for 2018 through February 2019 be refunded in this case, would you have any concerns with IRS normalization rule violations?

A. No. The normalization consistency rule is found at §168(i)(9)(B) of the Internal Revenue Code. It provides the following:

> (ii) Use of inconsistent estimates and projections The procedures and adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (A)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other 2 such items and with respect to the rate base.

In effect, the consistency rule says you cannot use a projection for ratemaking purposes for one of the listed items – tax expense, depreciation expense or deferred taxes – without using the same projection for the other two items and rate base. For example, the rule could prohibit accruing an additional return on deferred taxes beyond the end of the test year without updating rate base, tax expense and depreciation for the same time period.

It is important to note that the amortization of excess ADIT is <u>not</u> one of the enumerated items included in the consistency rule. Moreover, there are various ratemaking mechanisms available to alleviate any concerns about normalization violations.

Q. What mechanisms have other utilities employed to help protect against any normalization violation?

A. In a recent proceeding in Oklahoma, Mr. Randy Hamlett, on behalf of AEP-PSO, sets forth two approaches in his testimony that would allow the utility to amortize excess protected deferred taxes in 2018 without running afoul of the normalization rules. At page 3 of his responsive testimony in Oklahoma Cause No. PUD 201700572, he provides the following explanation:

> PSO needs flexibility to comply with the Average Rate Assumption Method (ARAM) used in amortizing excess protected deferred taxes should amounts change when the federal income tax return is filed to avoid a normalization violation that would have a long-term negative impact on PSO's customers. This flexibility can come from either a true-up in the refund rider to the actual ARAM value, or the Commission providing PSO the ability to move amortization of excess deferred taxes between the "protected" and "unprotected" buckets to avoid over amortizing the "protected" bucket.

This testimony is helpful in this proceeding for several reasons. First, it dispels the concerns raised by some utilities that the protected excess ADIT numbers could change when the utility files its 2017 tax returns. Mr. Hamlett addresses this exact concern in the passage above. His testimony also sets forth two approaches for avoiding normalization rule violations: (1) the commission can implement a true-up mechanism in a refund rider or (2) the commission can merely provide AEP-PSO with the flexibility to move amortization of excess ADIT between the "protected" and "unprotected" buckets.

Q. Why do you have confidence in AEP-PSO's proposed approach?

A. AEP is one of the country's largest investor-owned utilities with seven operating companies providing service in 11 states, including Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. AEP is well aware of the normalization rules and how to avoid violating them. Moreover, AEP's approach is a reasonable and effective means of returning the excess deferred taxes to customers and is in keeping with my interpretation of the consistency requirements within the normalization rules. This approach is also similar to the treatment of other utilities across the country in dealing with this issue.

Q. Are there other ways of handling the amortization of protected EDIT in the interim period before a new rate case?

A. Yes. Many utilities chose to merely amortize the protected EDIT to a regulatory liability account starting in 2018, to be accumulated and returned to ratepayers at the utility's next rate proceeding. The bottom line is that all utilities that I know of have found ways to preserve all of the benefits of the protected EDIT amortization for ratepayers, without violating any IRS normalization rules. This is the correct approach.

B. TCJA Treatment in Other States

Q. Have you monitored the treatment of TCJA impacts in other states for ratemaking purposes?

A. Although I have not conducted a comprehensive study of how the new tax law is being treated in every state, I am aware of how it is being treated in several states from my involvement in various TCJA proceedings. A synopsis of the treatment of the TCJA in other jurisdictions, ***not already discussed above***, is set forth below.

California In California, PacifiCorp filed an application with the California Public Utilities Commission requesting authorization to establish a "Tax Reform Memorandum Account" in order "to track for future credit to customers, amounts related to the reduction in the federal corporate income tax rate and related changes in the net deferred income tax liabilities associated with the Tax [Cuts and Jobs] Act." (*See* Exh. MEG-5.1, Application of PacifiCorp for Approval of a Tax Reform Memorandum Account and Request for Expedited Consideration.)

Oregon In Oregon, PacifiCorp made a similar request, seeking authorization to "defer the expected impacts associated with the income tax provisions enacted by the Tax [Cuts and Jobs] Act" and "defer for future credit to customers, amounts related to the reduction in the federal corporate income tax and related changes in deferred income tax liabilities." (*See* Exh. MEG-5.2, Application for Deferred Accounting). In making its request, PacifiCorp noted that denying the request would result in "the collection of revenue requirement at the higher tax rate will remain in general business revenues." (*Id.*)

Washington In Washington, PacifiCorp made the same request. There, PacifiCorp requested that the Washington Utilities and Transportation Commission "defer the expected impacts associated with the income tax provisions enacted by the Tax [Cuts and Jobs] Act." (*See* Exh. MEG-5.3, Petition for Accounting Order.)

Utah In Utah, PacifiCorp also made the same request. There, PacifiCorp requested "an order authorizing the Company to defer all revenue requirement impacts associated with the income tax provisions enacted by the 2018 Tax Act ..." (*See* Exh. MEG-5.4, Petition for Accounting Order.)

Montana The Public Service Commission of Montana ("PSCM") recognized upon passage of the TCJA that "[e]xpedient action by the Commission is necessary so that the Commission's options relative to this tax benefit are preserved." (*See* Exh. MEG-5.5, PSCM Order dated December 29, 2017, Docket No. N2017.12.94). In doing so, the PSCM specifically cited the prohibition against retroactive ratemaking as problematic. (*Id*.) The PSCM ordered utilities "to record on their books as a deferred liability, in an appropriate account, the estimated reduction in [Federal Income Tax] resulting from the 2017 Tax Act." (*Id*.) The PSCM also ordered utilities to "recognize as a deferred liability the estimated reduction of the utilities' revenue requirement resulting from the normalization requirements of the legislation." (*Id*.) In issuing the decision, the PSCM's Chairman said "The Commission wants to ensure that this money is not simply captured by shareholders, but instead is directed in a way that provides a long-term benefit to the consumer." (*See* Exh. MEG-5.6, PSCM Press Release dated December 27, 2017).

Tennessee The Tennessee Public Utility Commission ("TPUC") also determined that "since the tax benefits [of the TCJA] are immediate and to preserve the Commission's options relative to this tax benefit, the Commissioners determined that utilities should use deferral accounting to capture the benefits of tax reform." (*See* Exh. MEG-5.7, TPUC Order dated February 6, 2018, Docket No. 18-00001). More specifically, the TPUC ordered the state's five largest utilities to:

> track and accumulate monthly in a deferred account the portion of its revenue representing the difference between the cost of service approved by the Commission in its most recent rate case and the cost of serve that would have resulted had the provision for federal income taxes been based on 21% rather than 35%. (*Id*.)

The TPUC further ordered that the same utilities "[c]alculate the excess deferred tax reserve caused by the reduction in the corporate federal income tax rate and recognize as a deferred liability the estimated reduction of the utilities' revenue requirement resulting from the 2017 Tax Act." (*Id*.)

Oklahoma On January 9, 2018, the Oklahoma Corporation Commission ("OCC") ordered each of the investor-owned utilities in that state to accrue all savings from the TCJA, including both the rate change savings and the excess ADIT savings, in a regulatory liability account from the date of its order forward, to be returned to ratepayers. As an example, the OCC ordered PSO to:

> record a deferred liability beginning on the effective date of this Order, to reflect the reduced federal corporate tax rate to 21 percent and the associated savings in excess ADIT and any other tax implications of the Act on an interim basis subject to refund until utility rates are adjusted to reflect the federal tax savings through either a final order in rate case PUD 201700151, or a final order in PSO's next general rate case, or as otherwise ordered by the Commission.

As a further example, Oklahoma Gas and Electric ("OG&E") updated its rate case application, Cause No. PUD 201700496, to include both the 21 percent tax rate and the amortization of the excess ADIT balances, both protected and unprotected. OG&E is requesting that all of the savings available from the TCJA be included in the revenue requirement established in that case. (*See* Exh. MEG-5.8, OCC Cause No. PUD 201700572, Order No. 671981 (Jan. 9, 2018).)

Texas The Public Utility Commission of Texas ("PUCT") issued the order discussed above that requires utilities to:

> record as a regulatory liability beginning on January 25, 2018, the following: (1) the difference between the revenues collected under existing rates and the revenues that would have been collected had the existing rates been set using the recently approved federal income tax rates; and (2) the balance of excess accumulated deferred federal income taxes (ADFIT) that now exists because of the decrease in the federal income tax rate from 35% to 21%. (*See* Exh. MEG-5.9, PUCT Accounting Order Project No. 47945).

The Railroad Commission of Texas issued a similar order regarding Texas' gas utilities, requiring those utilities to "accrue on their books and records, as of the effective date of this Order, regulatory liabilities to reflect the impact of the decrease to the federal corporate income tax rate under the Act." (*See* Exh. MEG-5.10, TRC Order (Feb. 27, 2018)).

Arkansas The Arkansas Public Service Commission issued an order requiring investor owned utilities "to book regulatory liabilities to record the current and deferred impacts of the TCJA." This means all of the TCJA savings will be credited to ratepayers. (*See* Exh. MEG-5.11, APSC Docket 18-006-U, Order No. 1).

Louisiana The Louisiana Public Service Commission ("LPSC") issued an order on its own motion requiring utilities "to immediately track and record, as of January 1, 2018, as a regulatory liability (deferred liability), the impacts of the recently passed federal tax legislation." (*See* Exh. MEG-5.12, LPSC Special Order No. 13-2018). The LPSC further specified that the regulatory liability must record "those amounts necessary to reflect the reduced federal corporate tax rate expense of 21 percent and the excess accumulated deferred income taxes. It is the Commission's intent that all of the benefits resulting from the tax changes contained in TCJA will be flowed through, dollar-for-dollar, to Louisiana ratepayers." (*Id.*)

Maryland The Public Service Commission of Maryland ("PSCM") issued an order on January 12, 2018, requiring that Maryland utilities "track the impacts of the TCJA beginning on January 1, 2018 and apply regulatory accounting treatment, which includes the use of regulatory assets and regulatory liabilities, for all impacts resulting from the TCJA." (*See* Exh. MEG-5.13, PSCM Case No. 9473, Order No. 88530).

Kentucky The Public Service Commission of Kentucky issued an order on December 27, 2017, requiring certain electric utilities to "record a deferred liability starting January 1, 2018, to reflect both the reduced federal corporate tax rate expense of 21 percent and the excess deferred accumulated income taxes to be returned to ratepayers over the next 20 years." (Exh. MEG-5.14, PSCK Case No. 2017-00477, Order at 2 (Dec. 27, 2017)).

Q. What do you conclude from the treatment of the TCJA ordered in other states?

A. I conclude that the PSE's attempts to reverse (amortize) the protected excess EDIT to shareholders is ***not*** consistent with the treatment being ordered in other states. I further conclude that utilities across the country have been able to defer all of the benefits of the TCJA, including the reversal of protected EDIT, to be returned to ratepayers at a future rate proceeding, without running afoul of any normalization rule violations.

Q. What do you recommend?

A. I recommend that the Commission order PSE to place all the protected excess EDIT reversed (amortized) to expense from January 2018 through February 2019 in a regulatory liability account to be amortized back to ratepayers over a 24-month period beginning with new rates in this case.

Q. Does this conclude your testimony at this time?

A. Yes, it does.