PUGET SOUND ENERGY
The Energy To Do Great Things

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March 27, 2015

Via Electronic Mail

Steven V. King, Executive Director and Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
1300 S. Evergreen Park Drive S.W.
Olympia, Washington 98504-7250

Re: Docket U-150040
Comments of Puget Sound Energy, Inc. on Investigation of possible ratemaking mechanisms to address utility earnings attrition

Dear Mr. King:

Puget Sound Energy, Inc. (PSE) submits the following comments in response to the request in the Washington Utilities and Transportation Commission's (Commission) Notice of Opportunity to File Written Comments (Notice) issued in Docket U-150040.

PSE is a combined electric and natural gas utility serving more than 1 million electric customers and approximately 770,000 natural gas customers in western Washington State. PSE is a vertically integrated utility that owns and operates significant energy generation and delivery resources to safely and reliably serve customers. PSE owns, operates and maintains a mix of approximately 3,600 MW of generation resources, along with energy delivery systems that are equivalent in length to four roundtrips from Seattle to Washington, D.C. (electric lines) or a once around the Earth at the equator (natural gas lines).

Introduction

PSE appreciates the Commission's focus on ensuring financially healthy utilities including this investigation to better understand the causes of utility earnings attrition and possible ratemaking mechanisms to address those causes. As used in the discussion that follows, PSE defines attrition as the erosion of a company's earnings over time when the relationship between test period rate base, expenses and revenues used set rates does not hold in the period that these rates are in effect. For jurisdictions that use a historic test period, attrition occurs when the growth in rate base and expenses outpaces the growth in revenues after the test period.

Like many other utilities, PSE has been unable to earn its authorized return on equity (ROE) in recent years despite frequent rate case filings. PSE's filed Commission Basis Reports (CBRs) demonstrate that PSE has earned less than its authorized return on equity, despite the frequent increases in general rates during the same time period. The tables below provide a comparison of PSE's actual ROE, as reflected on its CBRs, to the authorized ROE in place at the end of the respective calendar year for electric operations (Table 2) and gas operations (Table 3).

Table 2. Comparison of PSE's Actual Electric ROE to Authorized ROE

	Return on Equity	
Year	**Normalized**	**Authorized**
2013	9.06%	9.80%
2012	8.11%	9.80%
2011	6.98%	10.10%
2010	5.57%	10.10%
2009	5.63%	10.15%
2008	5.94%	10.15%
2007	9.89%	10.40%

Table 3. Comparison of PSE's Actual Gas ROE to Authorized ROE

	Return on Equity	
Year	Normalized	Authorized
2013	8.62%	9.80%
2012	8.78%	9.80%
2011	7.30%	10.10%
2010	5.92%	10.10%
2009	5.61%	10.15%
2008	6.32%	10.15%
2007	8.07%	10.40%

Moreover, the problem of attrition is not unique to PSE or even Washington State. Regulators throughout the country, including in Washington, have been approving new and innovative regulatory frameworks to address the challenges of maintaining financially healthy utilities while also promoting energy efficiency and the continued modernization of infrastructure. These mechanisms include many of those that will be discussed below.

Guiding Principles for PSE's Evaluation of Mechanisms to Address Attrition

The variety of regulatory frameworks implemented around the country shows that no one mechanism perfectly addresses all causes of utility earnings attrition over time. There are no silver bullets. All mechanisms have benefits and shortcomings that evolve over time as circumstances change. In some cases, benefits in one time period can become shortcomings in another time period (discussed further below). Because of this, PSE remains flexible in the specific mechanism(s) used to address attrition, but is generally guided by a set of principles in its evaluation of the alternative mechanisms that are available. Students of ratemaking may recognize these principles, as shown below, as generally aligning with those advocated by Professor James Bonbright.

a. **Effective:** Addresses the source of earnings attrition

b. **Simple:** Reasonably easy for parties and the Commission to understand and the utility to administer

c. **Durable**: Relatively low risk of re-litigation by parties

d. **Auditable**: Relatively easy for parties and the Commission to track

e. **Efficient**: Aligned with prudent utility management

f. **Equitable**: Consistent with the regulatory compact and Hope & Bluefield

With that background, PSE offers the following comments in response to the specific questions posed in the Commission's request for comments in this docket.

PSE Responses to Specific Commission Questions

1. **Your organization's perspective on the cause(s) of utility earnings attrition, e.g. high inflation, aggressive capital investment in infrastructure, low/no load growth.**

As noted earlier, utility earnings attrition typically stems from a combination of factors that change over time. PSE's recent experience illustrates this.

The attached Exhibits 1 and 2 demonstrate the variety of factors working to erode PSE's ability to earn its authorized ROE, specifically costs to maintain and update energy delivery systems outpacing growth in customers and load (i.e. revenues). Both exhibits use data for electric and gas operations from PSE's approved compliance filings over five general rate cases (2003-2010). As shown in Exhibit 1, electric customer growth, a proxy for revenue growth, increased 1.3 percent on average over that period while growth in electric depreciation, rate base and operating expenses per customer increased at rates of 4.7 percent or higher. Exhibit 2 shows the same trend for gas operations as customers grew at a 1.9 percent rate while costs increased between 2.2 and 3.5 percent. Both exhibits show costs outpacing customer growth, again a proxy for revenue growth, causing attrition that reduces PSE's ability to earn its authorized ROE.

Capex and Inflation

Looking forward, PSE must continue to make the necessary infrastructure investments to ensure safe and reliable energy delivery systems even as inflation makes those investments more expensive. In addition, timely recovery of those investments remains critical. PSE projects approximately $1.9 billion in capital investments during the next three years to add new and replace aging infrastructure (e.g., pipes, poles and wires) to meet regulatory requirements and maintain reliable service to customers.

Capital Expenditure Projections (Dollars in Thousands)	2015	2016	2017
Total energy delivery, technology and facilities expenditures	$ 593,606	$ 671,060	$ 674,555

Source: 2014 PSE form 10-K

However, the costs of replacing aging infrastructure continue to increase. The cost to replace an aging system asset today needs to be compared to the cost of its original installation, which, on average, was approximately 30-35 years ago. In 1980, the average cost to purchase and install a 45-foot distribution pole was $530; by 2014, the cost increased to over $4,400. During 2014, for example, PSE installed approximately 2,157 distribution poles. This replacement increased the Company's depreciation expense per unit for these items by eight times the 1980 cost of comparable items.

As another example, the cost to purchase and install four-inch diameter plastic gas main has increased from $9 per foot in 1980 to $110 per foot in 2014. During 2014 PSE replaced nearly 25 miles of four-inch diameter plastic gas main. This replacement increased depreciation per unit by over 12 times the 1980 cost of comparable items. For planning purposes, PSE projects inflation to increase approximately 2.5 percent per year.

Load Growth

At the same time PSE continues to make the necessary investments into aging energy delivery systems, the Company's load forecast shows an overall lower system-wide rate of growth than in the past although some pockets of the service territory will experience more robust growth than others. The current forecast is showing that overall system-wide load growth is not an accurate predictor of the need to invest in both new and replacement of aging local utility infrastructure. The most up-to-date forecast predicts a 1.6 percent system wide average annual rate of growth (AARG) versus the 2.0 AARG forecasted in the 2012 Integrated Resource Plan. King County demonstrates this disaggregated growth. PSE's Eastside service territory in King County shows a 2.5 percent AARG while the rest of the county shows 0.3 percent[1]. The impacts of lower load and customer growth in combination with the need to spend to replace infrastructure creates barriers against PSE earning its authorized ROE.

Timely recovery (i.e. Test year/rate period)

Annual costs at PSE are increasing at a faster pace than revenues, and it remains necessary to ensure retail rates are sufficient so that growth in revenues are aligned with growth in PSE's prudently incurred costs. The ratemaking practices in Washington that have utilized a modified historical test year with limited pro forma adjustments have not provided for adequate and timely recovery of costs and rates that are just, fair, reasonable and sufficient. As illustrated earlier, the regulatory lag created by these ratemaking practices has led to PSE earnings erosion and contributed to the Company's inability to earn its authorized ROE.

In addition, traditional mechanisms in place that could be used to address attrition have become more limited and have therefore made it even more difficult, if not impossible, for the Company to realistically achieve its authorized ROR. Pro forma adjustments provide a good example of mechanisms that have become more limited over time. Over the past several years, the Commission has deviated from the historical precedent of the "known and measurable standard" for pro forma adjustments to a far more narrow view of this standard. Historically, the Commission allowed pro forma adjustments to be based on reasonable estimates and professional experience, not the strict actual experience standard of today. During a 1997 case (*WUTC v. Wash. Natural Gas*, Docket. U-77-47 (1977) the Commission allowed a projection in maintenance costs stating that "not all things in a rate case are provable with absolute certainty or precisely measurable." More recently, the view of this standard has shifted from considering and allowing estimated costs to actual costs. One example is a deferral adjustment allowed under RCW 80.80.60 that Commission Staff applied to PSE's property taxes. The deferral adjustment is based on PSE's estimated total costs to construct the facility rather than the actual costs plus known and measurable costs

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[1] PSE Integrated Resource Plan presentation to Technical Advisory Group, March 16, 2015

through a certain time period. During PSE's 2009 general rate case (UE-090704), the Commission Staff calculated the deferral adjustment for PSE's Wild Horse Expansion to include property taxes. A few years later during PSE's 2011 general rate case (UE-111048), the Commission Staff proposed to remove property taxes from its pro forma adjustment calculation for PSE's Lower Snake River Phase 1 citing the Company should recognize property taxes on a cash basis. As discussed further below, the calculation of property taxes was ultimately resolved using a tracker mechanism, but it's important that the standard for known and measurable be durable and consistent across successive ratemaking proceedings.

PSE does acknowledge, however, that more recent tools approved by the Commission may help address earnings attrition and regulatory lag. Order 07 in PSE's decoupling application (UE-121697, UE-121705) and its expedited rate filing (UE-130137, UG-130138) allows PSE to implement electric and natural gas decoupling mechanisms, a one-time expedited rate filing, and a multi-year rate plan. These mechanisms may provide PSE a better opportunity to recover its fixed costs, reduce regulatory lag, and enhance the potential to earn its authorized rate of return. PSE will demonstrate the results of Order 07 during its next rate case.

2. **Your organization's preferred ratemaking mechanism(s) for addressing each of the forms of earnings attrition identified above, e.g. an attrition allowance, pro forma plant in rate base, construction work in progress (CWIP) in rate base, or future test year. Please include a discussion of the benefits and shortcomings of your preferred mechanism and of alternative mechanisms. Also, discuss whether the different causes of attrition require different ratemaking solutions, in your respective view.**

PSE observes that the Commission regulates multiple utilities, and some tools may work better for one utility and its customers versus others. Therefore, it is not necessarily the case that a particular mechanism will always be useful to address a particular problem. Ratemaking is a multidimensional undertaking and must recognize all factors that are contributing to any given utility's earnings attrition. PSE will discuss some of the shortcomings and benefits of a few of the regulatory mechanisms used today.

Multi-year Rate Plan

PSE currently operates under a multi-year rate plan that includes decoupling mechanisms along with K-factor adjustments. The decoupling mechanism (Dockets UE-121697 and UG-121705) weakens the link between revenues collected and the amount of energy PSE sells to cover fixed costs of delivering energy. PSE's decoupling mechanism is an important tool for operating as a financially healthy utility during times of low load growth while maintaining a commitment to capital investments, energy efficiency and conservation.

The K-Factor is an important part of PSE's decoupling mechanisms and helps to address the attrition occurring as a result of the costs growing at a faster pace than customer growth. The K-factor provides pre-determined increases to authorized revenue per customer that helps to address earnings attrition, which when combined with the stay-out period provided further incentives for the company to manage its costs and seek efficiencies.

Expedited Rate Filing (ERF)

PSE's expedited rate filing (ERF) (dockets UE-130137 and UG-130138) was a one-time filing made in February 2013 using an expedited filing methodology proposed to help address the attrition and regulatory lag inherent in Washington's historical ratemaking approach. The methodology proposed expedited consideration for limited restating adjustments that utilize existing ratemaking methods previously approved by the Commission. The filing could not contain changes to rate of return, rate spread or rate design.

PSE views the expedited nature of the ERF as an important tool to address earnings attrition, especially under conditions that include low load growth, increased capital spending, high inflation and a historical ratemaking approach that can create regulatory lag.

Pro Forma Adjustments

In certain scenarios, pro forma adjustments can be important for allowing timely cost recovery and reducing attrition. Examples were provided earlier of the types of pro forma adjustments allowed by the Commission in the past. However, as noted earlier, the Commission's more narrow use of these adjustments have greatly diminished their value in addressing the effects of earnings attrition.

PCA/PGA

PSE's costs for generating or purchasing power and natural gas commodity costs are accounted for using power cost adjustment (PCA) and purchased gas adjustment (PGA) mechanisms. PSE's PCA mechanism accounts for differences in the Company's modified actual power costs relative to a power cost baseline and provides for a sharing of power costs between the Company and ratepayers. The PGA mechanism is a pass through mechanism that allows PSE to recover the costs of natural gas purchased on the open market to customers without any profit to the company. Both the PCA and PGA allow forward-looking projections into the rate year, which include a projection of the load-reducing effects of energy efficiency. The limited regulatory lag associated with these costs enhances the Company's ability to recover these costs during the rate year.

PSE views the PCA and PGA mechanisms as important tools to manage commodity costs driven by market forces largely beyond the control of the Company. These tools are especially important during times of volatile commodity costs. The structure of these mechanisms, including forward looking projections, improves the Company's ability to avoid earnings attrition.

Power Cost Only Rate Case (PCORC)

A Power Cost Only Rate Case (PCORC) is a limited-scope proceeding that was approved for PSE in 2002 by the Commission (Docket Nos. UE-011570 and UG-011571) to periodically reset power cost rates. In addition to providing the opportunity to reset all power costs, the PCORC proceeding also provides for more timely review of new resource acquisition costs and inclusion of such costs in rates closer to the time the new resource goes into service. The PCORC uses a targeted six-month decision timeline rather than the statutory 11-month timeline for a general rate case.

The PCORC is an important regulatory tool to address attrition and regulatory lag because it provides for recovery of a broader scope of costs than a tracker or rate rider and on a slightly more expedited timeline than a general rate case. The PCORC is important during times of commodity volatility, resource acquisitions, rising demand, inflation, and other economic conditions. However, the PCORC is not as effective as it could be at addressing the sources of utility attrition, since a large part of the costs and rate base continue to be set using historic test year levels.

Trackers or Rate Riders

Trackers and rate riders can be important regulatory tools when the utility is exposed to costs outside its control, especially if those costs can be volatile. Tracker and rate rider mechanisms are limited in scope and provide for more timely and accurate cost recovery than traditional historic test year mechanisms thereby reducing lag and helping to address earnings attrition. Property taxes provide a good example of costs well suited for a tracker mechanism because they take a long time to calculate and PSE is subject to rates set by state and local taxing authorities. The amount of time to collect accurate property tax information (16 months) does not comport with the Washington's modified historic test year ratemaking approach (based on 12 months). The methodology to calculate property taxes under the traditional modified historic test year approach violates the matching principle because it fails to match the costs in the test year with assets owned in the test year. In addition, a majority of the property tax during a test year is an estimate which contradicts the current interpretation of the "known and measureable changes that are not offset by other factors." PSE filed and the Commission approved that the Company collect property taxes through a property tax tracker mechanism based on cash payments of property tax made by PSE during the year (PSE Tariff Schedule 140). Any difference between the cash payments and property tax valuation accruals will be deferred and recovered in the tracker.

CWIP/Pro Forma studies/Future test years

There could be benefits to including construction work in progress (CWIP) in rate base during times of very large capital investments. The shortcoming of CWIP in rate base is that the utility is still not able to recover on any future investment expected to be made during the rate year and it complicates the used and useful standard. In addition, if the approaches to their implementation are well-defined, forecasted test years, attrition adjustments, or pro forma plant in rate base could be helpful regulatory tools.

3. If your organization prefers the Commission adhere to a historical test year ratemaking approach, please discuss why it would or not it would be appropriate to consider potential earnings attrition in that historical year context.

PSE prefers that any test year used by the Commission during ratemaking adequately represent the relationship between rate base, expenses and revenues in the rate year. Historic, modified historic, forward looking or other types of test years can all work as long as the relationship discussed above is maintained.

4. If your organization has a preferred mechanism(s), please discuss the requirements and parameters necessary for calculating the adjustment(s). Please include in your comments responses to the following questions:

- **a. Should an attrition analysis include historical data only?**
- **b. Should rate-year capital budgets be considered?**
- **c. Should there be a "bright line" cutoff date for the including pro forma plant in rate base?**
- **d. What level of precision should be expected for projected capital budgets (budgeted to actual) for ratemaking?**

a. Attrition analysis should not necessarily include historical data only. The analysis should include all appropriate and available information that is representative of what is to be expected during the rate year, whether that's forward or backward looking. The analysis should consider any changes expected during the rate period, up or down, to reflect costs during the rate period.

b. Yes, all appropriate costs expected during the rate year should be considered.

c. No, this could limit appropriate costs from being considered in the rate year and potentially violate the matching principle if benefits were considered but not the associated costs.

d. A level or precision that ensures the appropriate costs are reflected in rates during the rate period. Levels of precision can be achieved using a combination of mechanisms discussed in PSE's response to question 2.

5. Please provide any other information, discussion, analysis, or documentation you believe would help inform the Commission on this issue?

As demonstrated earlier, PSE has recently earned less than its authorized return on equity, despite the frequent increases in general rates and changes to the regulatory mechanisms used by the Commission. The goal of any mechanism or method should be to align costs, revenue and rate base during the timeframe that new rates will be in effect. No one mechanism can adequately address all causes of utility earnings attrition over time. Therefore, it is important that the Commission maintain a robust toolbox that can adequately respond to the evolving conditions facing utilities.

PSE appreciates the opportunity to provide these responses to the questions identified above in the Notice of Opportunity to File Written Comments. Please contact Nate Hill, Regulatory Affairs Initiatives Manager at (425) 457-5524 or myself at (425) 456-2110 for additional information about this filing.

Sincerely,

Manager Regulatory Initiatives & Tariffs

for Ken Johnson
Director, State Regulatory Affairs

cc: Simon ffitch
Sheree Carson

Attachment A
Exhibit 1

PUGET SOUND ENERGY
ANNUAL GROWTH RATE BASED ON GRC COMPLIANCE FILING WORKPAPERS
ELECTRIC OPERATIONS

		2004 GRC	2006 GRC	2007 GRC	2009 GRC	2011 GRC	% Annual Growth in O&M			
	Test Year	Sep-03	Sep-05	Sep-07	Dec-08 (Note 1)	Dec-10 (Note 1)	2004GRC - 2011GRC 7.25	2006GRC - 2011GRC 5.25	2007GRC - 2011GRC 3.25	2009GRC - 2011GRC 2.00
1	**Load (input tab)**									
2	Electric	19,334,018,640	20,339,226,968	21,283,655,838	21,821,673,792	21,143,300,002	1.2%	0.7%	-0.2%	-1.6%
3										
4	**Electric Expenses**									
5	Other Power Supply Expense	52,551,925	77,648,296	96,183,223	107,091,100	124,341,933	12.6%	9.4%	8.2%	7.8%
6	PCA Transmission	485,960	862,248	1,136,455	1,523,617	1,419,635	15.9%	10.0%	7.1%	-3.5%
7	Transmission & Distribution Expense	63,736,286	65,086,999	75,095,489	82,334,864	92,084,397	5.2%	6.8%	6.5%	5.8%
8	Customer Account & Services Expenses	37,542,803	37,706,383	41,878,822	44,367,720	49,173,646	3.8%	5.2%	5.1%	5.3%
9	Admin & General Expenses	70,951,920	74,379,848	81,986,794	89,886,009	99,871,160	4.8%	5.8%	6.3%	5.4%
10	Total Electric Expenses	225,268,893	255,683,774	296,280,783	325,203,310	366,890,771	7.0%	7.1%	6.8%	6.2%
11	Electric Non-pca related	172,231,009	177,173,230	198,961,105	216,588,593	241,129,203	4.8%	6.0%	6.1%	5.5%
12	**Electric Depreciation**									
13	Production	37,335,853	59,620,924	51,741,842	50,072,838	93,722,074	13.5%	9.0%	20.1%	36.8%
14	PCA Transmission	4,859,223	4,861,051	3,805,774	4,056,906	3,843,499	-3.2%	-4.4%	0.3%	-2.7%
15	Transmission & Distribution	71,715,862	76,838,397	87,146,104	92,434,248	101,680,414	4.9%	5.5%	4.9%	4.9%
16	General , Intangible	11,381,296	10,068,281	19,226,023	15,196,346	20,477,642	8.4%	14.5%	2.0%	16.1%
17	Non-Tracker	-	-	-	13,993,264	-	0.0%	0.0%	0.0%	0.0%
18	Electric Depreciation	125,292,233	151,388,653	161,919,743	175,753,602	219,723,630	8.1%	7.4%	9.8%	11.8%
19	Total T&D and General	83,097,158	86,906,678	106,372,127	107,630,594	122,158,056	5.5%	6.7%	4.3%	6.5%
20										
21	**Electric Amortization**									
22	Production	4,713,860	3,004,881	5,612,906	11,298,008	11,275,733	12.8%	28.6%	23.9%	-0.1%
23	Transmission &Distribution	-	-	-	-	-	0.0%	0.0%	0.0%	0.0%
24	General , Intangible	19,142,502	19,349,756	25,514,388	28,304,530	25,477,630	4.0%	5.4%	0.0%	-5.1%
25	Non-Tracker	1,498,249	2,793,718	1,805,160	2,112,845	3,194,525	0.0%	0.0%	0.0%	0.0%
26	Electric Amortization	25,354,610	25,148,354	32,932,455	41,715,383	39,947,889	6.5%	9.2%	6.1%	-2.1%
27	Total T&D and General	19,142,502	19,349,756	25,514,388	28,304,530	25,477,630	4.0%	5.4%	0.0%	-5.1%
28										
29	T&D/General Depn & Amort (ln19 + ln27)	102,239,659	106,256,434	131,886,516	135,935,123	147,635,687	5.2%	6.5%	3.5%	4.2%
30										
31	**Electric Ratebase**									
32	Production	751,245,624	1,234,946,228	1,246,912,240	1,583,950,372	2,330,849,778	16.9%	12.9%	21.2%	21.3%
33	PCA Transmission	120,648,501	113,206,055	107,422,863	102,337,940	94,699,228	-3.3%	-3.3%	-3.8%	-3.8%
34	Transmission & Distribution (Note 1)	1,408,241,596	1,395,944,754	1,641,251,984	1,922,288,883	2,172,658,792	6.2%	8.8%	9.0%	6.3%
35	General , Intangible , Other (Note 1)	221,758,096	203,380,656	180,138,722	-	-	-100.0%	-100.0%	-100.0%	0.0%
36	Non-Tracker	42,776,224	29,838,500	127,847,726	188,037,777	255,040,634	0.0%	0.0%	0.0%	0.0%
37	Electric Ratebase	2,544,670,041	2,977,316,193	3,303,573,535	3,796,614,971	4,853,248,431	9.3%	9.8%	12.6%	13.1%
38	Total T&D and General	1,629,999,692	1,599,325,411	1,821,390,706	1,922,288,883	2,172,658,792	4.0%	6.0%	5.6%	6.3%

	Average Customer Count from GRC (2)		1,004,833	1,041,219	1,060,704	1,075,057	1.3%
	Cost per customer:						
39	Depn		$ 86.49	$ 102.16	$ 101.47	$ 113.63	5.3%
40	Ratebase		$ 1,591.63	$ 1,749.29	$ 1,812.28	$ 2,020.97	4.7%
41	Operating Expense		$ 176.32	$ 191.08	$ 204.19	$ 224.29	4.7%

(Note 1) For the 2009 GRC, 2011 GRC and 2011 CBR, General, Intangible and Other plant is included on line 35.
(Note 2) Customer Counts from PSE's Response to Public Counsel Data Request 78, Attachments A

Attachment B
Exhibit 2

PUGET SOUND ENERGY
ANNUAL GROWTH RATE BASED ON GRC COMPLIANCE FILING WORKPAPERS
NATURAL GAS OPERATIONS

	2004 GRC	2006 GRC	2007 GRC	2009 GRC	2011 GRC	% Annual Growth in O&M			
						2004GRC - 2011GRC	2006GRC - 2011GRC	2007GRC - 2011GRC	2009GRC - 2011GRC
1 **Test Year**	Sep-03	Sep-05	Sep-07	Dec-08	Dec-10				
2						7.25	5.25	3.25	2.0
3 **Load**									
4 Gas	1,033,465,074	1,038,450,901	1,084,208,169	1,120,309,121	1,072,668,096	0.5%	0.6%	-0.3%	-2.1%
5									
6 **Gas Expenses**									
7 Other Power Supply Expense	1,162,087	1,555,800	1,769,111	1,881,592	1,959,232	7.5%	4.5%	3.2%	2.0%
8 Transmission & Distribution Expense	26,259,234	34,532,486	43,207,192	52,101,244	49,783,566	9.2%	7.2%	4.5%	-2.2%
9 Customer Account & Services Expenses	23,088,164	25,038,278	27,397,683	29,110,812	31,704,844	4.5%	4.6%	4.6%	4.4%
10 Admin & General Expenses	32,698,303	41,714,840	40,022,534	43,076,879	43,995,146	4.2%	1.0%	3.0%	1.1%
11 Total Gas Expenses	83,207,788	102,841,404	112,396,520	126,170,527	127,442,788	6.1%	4.2%	3.9%	0.5%
Non-power supply related	82,045,701	101,285,604	110,627,409	124,288,935	125,483,555	6.0%	4.2%	4.0%	0.5%
12									
13 **Electric Non-pca related**									
14 Production & Gas Storage	1,076,351	1,294,251	934,365	1,011,473	1,278,337	2.4%	-0.2%	10.1%	12.4%
15 Transmission & Distribution	52,617,414	59,340,713	75,944,262	80,729,161	85,358,207	6.9%	7.2%	3.7%	2.8%
16 General , Intangible , Other	4,182,553	4,321,030	10,051,696	7,109,187	9,195,128	11.5%	15.5%	-2.7%	13.7%
17 Gas Depreciation	57,876,318	64,955,994	86,930,323	88,849,821	95,831,672	7.2%	7.7%	3.0%	3.9%
18 Less Prod, Storage, LNG	1,076,351	1,294,251	934,365	1,011,473	1,278,337	2.4%	-0.2%	10.1%	12.4%
19 Net Gas Depreciation (ln17 - ln18)	56,799,967	63,661,743	85,995,958	87,838,349	94,553,335	7.3%	7.8%	3.0%	3.8%
21									
22 **Gas Amortization**									
23 Production & Gas Storage	-	-	-	-	-	0.0%	0.0%	0.0%	0.0%
24 Transmission & Distribution	21,162	82,646	303,738	403,917	219,232	38.1%	20.4%	-9.5%	-26.3%
25 General , Intangible, Other	9,579,622	11,220,066	13,783,889	15,214,871	12,558,889	3.8%	2.2%	-2.8%	-9.1%
26 Gas Amortization	9,600,784	11,302,712	14,087,627	15,618,788	12,778,120	4.0%	2.4%	-3.0%	-9.5%
27									
28 T&D/General Depn & Amort (ln19 + ln26)	66,400,751	74,964,455	100,083,585	103,457,137	107,331,456	6.8%	7.1%	2.2%	1.9%
29									
30 **Gas Ratebase**									
31 Production & Gas Storage	22,042,681	25,973,805	27,896,986	27,244,685	39,751,535	8.5%	8.4%	11.5%	20.8%
32 Transmission & Distribution	925,750,507	1,037,271,755	1,191,070,429	1,301,847,809	1,414,064,871	6.0%	6.1%	5.4%	4.2%
33 General , Intangible , Other	118,543,578	106,130,161	90,793,405	85,446,599	101,077,864	-2.2%	-0.9%	3.4%	8.8%
34 Working Capital	1,345,790	10,976,022	37,506,872	52,980,352	78,334,208	75.2%	45.4%	25.4%	21.6%
35 Gas Ratebase	1,067,682,556	1,180,351,743	1,347,267,693	1,467,519,443	1,633,228,478	6.0%	6.4%	6.1%	5.5%
36 Less Production related	(22,042,681)	(25,973,805)	(27,896,986)	(27,244,685)	(39,751,535)				
37 Less Working Capital	(1,345,790)	(10,976,022)	(37,506,872)	(52,980,352)	(78,334,208)				
38 Total T&D and General	1,044,294,085	1,143,401,915	1,281,863,835	1,387,294,407	1,515,142,736	5.3%	5.5%	5.3%	4.5%

(Note 1) The 2007 GRC depreciation results shown on line 19, included a $9.3M adjustment resulting from the 07 Depreciation study approved in that filing.
Had the adjustment occurred in the 2006 GRC, the compound growth factor for the 2006 to 2011 period would have been 5.1%

2006 Gas Depreciation	63,661,743	
2007 GRC Depreciation Adjustment	9,262,448	
	72,924,191	5.1%

	2006 GRC	2007 GRC	2009 GRC	2011 GRC	
Average Customer Count from GRC (2)	678,712	717,732	737,836	750,800	1.9%
Cost per customer:					
39 Depn	$ 107.44	$ 119.82	$ 119.05	$ 125.94	3.1%
40 Ratebase	$ 1,684.66	$ 1,785.99	$ 1,880.22	$ 2,018.04	3.5%
41 Operating Expense	$ 149.23	$ 154.13	$ 168.45	$ 167.13	2.2%
Total Ratebase (ln 35)	$ 1,739.10	$ 1,877.12	$ 1,988.95	$ 2,175.32	4.4%

(Note 2) Customer Counts from PSE's Response to Public Counsel Data Request 78, Attachments B