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DOCKETS UE-17____/UG-17____
2017 PSE GENERAL RATE CASE
WITNESS: JON A. PILIARIS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-17____** **Docket UG-17____**

TWENTY-EIGHTH EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

JON A. PILIARIS

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 13, 2017

Puget Sound Energy Electric and Natural Gas Evaluation:

12/31/2016

THREE YEARS OF DECOUPLING

An Independent Third-Party Evaluation of Puget Sound Energy's Electric and Natural Gas Decoupling Mechanisms

H. Gil Peach & Associates LLC with
Forefront Economics, Inc. & Joseph Associates, Inc.

H Gil Peach   Mark Thompson   John Joseph

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Puget Sound Energy
Electric and Natural Gas Evaluation:
THREE YEARS OF DECOUPLING

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I. Executive Summary

This three-year decoupling study focuses on a set of researchable issues developed by Puget Sound Energy (PSE) in cooperation with the Conservation Resources Advisory Group (CRAG). We start this summary with the heightened focus in this study on the natural gas decoupling group (Schedules 23 & 53), due to the interaction of its high sensitivity to temperature with the 3% cap on a rate increase for an individual year. This decoupling group's weather sensitivity, in conjunction with the 3% rate cap, caused the overall rate increase for the natural gas residential decoupling group to be limited to 3% on May 1, 2015 and again on May 1, 2016. This means that cumulating deferral amounts are passed forward over two years and might well not be recovered for three or more years in a kind of snowball effect.

Although this path was built-in to the decoupling rate adjustment mechanism, it had been assumed in planning that deferred revenue recovery might be for a single year and not more. Cumulating deferral was a surprise. However, it is a fact that short cycles of warmer or cooler weather may run for sets of years (think El Niño and La Niña, which typically last from one to two years, but the short cycles may be longer, for example up to seven years[1]). If the three decoupling years in the study had happened to coincide with a short cooling cycle for Seattle (rather than a short warming cycle), the issue of cumulating deferrals due to interaction of the 3% rate cap and weather sensitive load would not have appeared. By luck, the three decoupling years in this study (2014, 2015 & 2016) coincided with a short warming cycle, so less natural gas was used in the residential sector causing the question of cumulating deferrals to surface for analysis.

Parties can differ about whether cumulating deferrals are an adverse impact of the PSE decoupling mechanism.

- On the one hand, cumulating deferrals are just a fact associated with short warming cycles, which are a kind of typical weather. Weather is a feature of the natural world, and that is how we see it analytically, here. This path was built-in to the rate adjustment mechanism and successfully limits customer cost in each particular year. The mechanism works as designed and the purpose of the built-in

[1] "El Niño and the Southern Oscillation, also known as ENSO is a periodic fluctuation (*i.e.*, every 2–7 years) in sea surface temperature (El Niño) and the air pressure of the overlying atmosphere (Southern Oscillation) across the equatorial Pacific Ocean. "National Oceanographic and Atmospheric Administration website, 12/26/2016: https://www.ncdc.noaa.gov/teleconnections/enso/.

rate cap is accomplished. The number of carryover years required for full revenue recovery is just an automatic feature of this design when interactive with a short warming cycle for a highly weather sensitive decoupling group. Supporting this perspective, in a recent review of decoupling, carryover is not portrayed as adverse, but is simply treated as a fact.[2] However the review notes that, to date, there has not been much experience with this feature.

- On the other hand, an adverse consequence is typically both unintended and a surprise. It is also typically a side-effect of an otherwise positive result. So in this study, it would be reasonable for parties who expect all revenue recovery to be realized in the year after the revenue obligation is incurred to see cumulating deferral as an adverse consequence of the PSE decoupling mechanism. The cumulating deferral across more two years might lead to a carryover of several years. It depends on the weather.

- It turns out, also, that PSE would prefer recovery within two years because otherwise there is a violation of one of the principles of the General Agreement on Accounting Principles (GAAP).

Whether or not we call it an adverse consequence – cumulating deferral, leading to a carryover for more than two years and a conflict of two GAAP principles (revenue recovery within two years vs. keeping revenue obligation paired with revenue recovery), occurred.

With regard to the size of effects in this study, we characterize each year's adjustment for each decoupling group as "small"; that is, at or under a 3% rate increase for each group. In most cases, the indicated adjustment was under 3%. In three cases, the 3% limit was imposed by the cap in the rate adjustment mechanism. In these cases, the overage was deferred for revenue recovery in the next year or over future years.

This examination is developed following specifications in an agreement among parties associated with the amended petition in Dockets UE-121697 and UG-121705 (consolidated), Order 07, June 25, 2013 and Order 09, November 1, 2013 in the Matter of the Petition of Puget Sound Energy, Inc. and Northwest Energy Coalition (NWEC) for an order authorizing Puget Sound Energy (PSE) to implement electric and natural gas decoupling mechanisms and to record accounting entities associated with the

[2] "Carryovers can range from one to several years to however long it takes to get full recovery." Migden-Ostrander, J., and Sedano, R. (2016). *Decoupling Design: Customizing Revenue Regulation to Your State's Priorities.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities.

mechanisms. Specific guidance for the third year evaluation was provided by PSE[3], reflecting discussion with the Conservation Resources Advisory Group (CRAG). The specifications include a draft report to be completed by November 30, 2016, followed by a presentation to the CRAG in early December 2016 and completion of the three-year evaluation report on December 31, 2016.

The study is an independent examination of three years of PSE's Electric and Natural Gas Decoupling by H. Gil Peach & Associates, Forefront Economics, Inc., and Joseph Associates, Inc. (hereafter referred to by name or by "we", "our", and "us"). The decoupling evaluation generally looks backwards to provide a factual reference as to "what happened" in actual implementation. The evaluation does not specifically address the load forecast, but does take into account the energy use targets already recognized for use as a basis in cost recovery. In a few places, we include some brief "facing forward" analysis and comments.

We conducted the study to answer the specified researchable issues that developed from the decoupling joint proposal by NWEC and PSE. These were specified in the initial Request for Proposals and were modified in the current Statement of Work.[4] The report also includes reference appendices:

- Appendix I is the record of Conservation Savings and Expenditures.
- Appendix II is a Summary of Decoupling Deferrals.
- Appendix III, *A Change in the Weather*, summarizes our analysis of the contextual factor of weather patterns and cost of natural gas as sources of background variation in customer bills.
- Appendix IV provides a collection of typical residential bills. While we work with arithmetic averages throughout the report, Appendix IV summarizes rate adjustments using the convention of a "typical" residential customer who uses an average of 1000 kWh or 68 therms per month.
- Appendix V includes the Responses to Data Requests used in this report. These responses do not include attachments, such as spreadsheets. Other Responses to Data Requests were also used, but were not directly cited in the study.

[3] Statement of Work to PSE Outline Agreement No. 4600009475, Rev1-0914 and governed by the terms and conditions of Master Services Agreement No. 4600007812 dated as of October 9, 2015.

[4] Ibid.

Study Questions & Answers

Here are the researchable issues questions with brief answers:

1. Q: Were the deferrals and rates calculated in accordance with the Commission Order?

A: Yes. Deferrals and rates conformed to Commission Orders – the method and the math is correct.

We implemented mathematical checks using information provided in responses by PSE to several of our Data Requests. For data from the beginning of decoupling through June 2016 (three years), deferrals and rates were calculated in accordance with WUTC decoupling orders.

In addition to our mathematical checks, since this data was audited by a professional audit team (Price Waterhouse) that has provided an opinion regarding the accuracy of the data, we are relying on this professional opinion for the financial integrity of the data.

We find that deferrals and rates were calculated correctly, in accordance with Commission orders. For additional detail, please see Section II.

- We find no problem in this area.

2. Q: What are the impacts of the decoupling tariff tracker adjustments?

A: The short answer is that results are mixed (Table 1.1). Overall, the yearly revenue impacts of the Schedule 142 surcharge are small. The pattern of results is generally as anticipated, with very small movements up and down for each decoupling group. However, the 3% cap was reached three times. This represents 17% of the 18 calculations for groups, or almost one-fifth of the calculations through year three. Therefore, for roughly 80% of the decoupling group calculations (across electricity and natural gas), the result did not exceed the cap. The 3% cap was reached once for the commercial and industrial decoupling group (Schedules 10 & 31) and twice for residential natural gas customers (Schedules 23 & 53).

The Schedule 142 decoupling and rate plan tariff rates are adjusted in May of each year. For the decoupling group that includes Commercial and Industrial Schedule 10 & 31, the May 2015 calculated electric Schedule 142 rate adjustment impact of 5.1% exceeded the 3% cap. In the 2016 filing, the rate adjustment dropped back down to a 2.0% impact on rates. Here, the 3% cap functioned as planned to limit the rate impact in 2015, and the full deferred amount from 2015 was amortized over customer bills in 2016.

The observed pattern is given by the sequence: 0.7%, 5.1%, 2.0%. This sequence shows the rate control tool (the 3% cap) working as planned: In one year the cap is reached and the deferred revenue is then amortized over the following year. There is no problem for this group, as demonstrated by the sequential pattern. If we add this case to the original fifteen cases (rate group years) for which there is no problem, we arrive at 16 of 18 cases with no problem.

This leaves a remaining instance of two cases (8.8% or, roughly 10% of instances), which together show a cumulating deferral pattern that was built into the operation of the adjustment mechanism but which was not expected in planning the pilot. These two cases involve only one group and illustrate what happens when deferred revenue cannot be amortized over the year following the year in which the debt was incurred. In the year after that, the amount of the deferred revenue from the first year plus an add-on of new deferred revenue cannot be fully billed. In this case, the amount to be recovered grows from the second to the third year. For the natural gas Residential Rate Group (Schedules 23 & 53), the Schedule 142 natural gas rate adjustment was limited by the 3% cap on rates for both the 2015 Filing and the 2016 Filing. The observed pattern is given by the sequence: -1.3%, 4.2%, 7.3%. This sequence shows the pattern when there are two warm years in a row, which is not unusual (the weather cycles warmer and cooler in short cycles). We expect that this sequence will continue to increment so long as significantly warmer than normal weather continues for additional years: for example, three years. At the end of the warming cycle, we expect a cooling cycle during which there will be complete revenue recovery and no carryover.

Residential natural gas is temperature sensitive due to heating being a large component of load. We suggest the potential problem of growing deferral balances could be addressed by raising the Rate Test from 3% to 5% for the residential natural gas decoupling group (only). In this study, the 3% cap has worked well for the electric decoupling groups and for the non-residential natural gas decoupling group and should be continued.

Table I.1: Effects of Schedule 142 Surcharge – DR 30.59

	2014 Filing	2015 Filing	2016 Filing
	Rates Effective May 1, 2014	Rates Effective May 1, 2015	Rates Effective May 1, 2016
Electric Decoupling Groups			
Residential	0.1%	2.9%	1.5%
Non-Residential	1.1%	2.4%	-0.1%
Schedules 12 & 26	1.3%	1.7%	1.2%
Schedules 10 & 31	0.7%	5.1%	2.0%
Gas Decoupling Groups			
Residential	-1.3%	4.2%	7.3%
Non-Residential	2.4%	0.8%	2.5%
Source: DR 30.59 Attachment A			

- For effects of the Schedule 142 surcharge in 2014, 2015 and 2016 using the convention of a customer using 1,000 kWh or 68 therms per month, please see Appendix V (Table XIII.1 through Table XIII.8).

- The impact analysis, called for in PSE's Amended Decoupling Petition filed in Docket UE-121697 and presented in Section III of this report, was performed for each of the traditional Cost of Service (COS) groups used by Puget Sound Energy. The variable analyzed was percentage contribution of Schedule 142 to the average monthly electric and natural gas bill. The variation by Cost of Service (COS) class within electricity and within natural gas is small. For additional detail, please see Section III.

- Overall effects: For the three years examined, overall impacts (and impacts by COS class) for most of the decoupling Schedule 142 tariff tracker adjustments for electricity are very small to small. However, the 3% "soft cap" for one electric decoupling group (Schedules 10 & 31) was reached in the rate adjustment implemented in May 2015. The cap was not reached for any electric decoupling group in May 2016, providing for rapid revenue recovery, as planned. Overall impacts on the gas side are small for the non-residential decoupling group. For residential natural gas (Schedules 23 & 53) the cap was reached in May 2015 and again in May 2016, causing a cumulative increase in deferred revenue recovery. This provided an opportunity to observe the working of the "soft cap" part of the decoupling mechanism, which is working according to plan. However, a cumulative increase in unrealized revenue had not been anticipated in planning. We suggest the potential problem of growing deferral balances could be addressed by raising the Rate Test from 3% to 5% for the residential natural gas decoupling group (only) while leaving the 3% cap in place for all other decoupling groups. If the revenue requirement is correct, this is a "pay now" or "pay later" situation, caused by the interaction of the 3% level of the cap and with highly weather-sensitive load during a short warming cycle.

- We assert that the revenue requirement is a result of practical and physical requirements for appropriately maintaining the electric and gas systems. Then, under other rate-making approaches, the material revenue requirement would be essentially the same. Since the revenue requirement is understood as representing a real number that reflects a physical reality for the electric and gas systems, alternative rate-making approaches are not available as solutions to the indicated *amount* to pay. Other approaches can only affect *allocation* of the amount. Alternative approaches, such as tweaking how weather fits into the calculation, raising the fixed portion of the rate, making the deferral true-up more frequent or creating additional special fixed charges (for example, the possibility of a variety of grid services fees) might be used to shift recovery from one decoupling group to another or from one year to another, but cannot affect the amount of the actual revenue requirement to run and maintain the electric and gas systems. To challenge this result, only a successful technical demonstration that the revenue requirement is incorrectly set too high would work. This could happen in a subsequent full rate case. The other potential "fixes" work only at the level of allocation among parties or over time.

- We are employing a physical or realist understanding of the revenue requirement: there is a real number in the real world that represents the revenue requirement. The decoupling rate adjustment mechanism, including the K-factor, approximates this number. Alternatively, in a non-realist perspective, a party could choose to assert that the revenue requirement is subjective in the current PSE decoupling rate adjustment mechanism (that operates between full rate cases). In that case, a weather tweak or some other redesign of a component of the adjustment mechanism that operates between full rate cases could be constructed to lower bills and eliminate the appearance of cumulating deferral amounts. However, from a physical or realist perspective, if the PSE decoupling revenue requirement is correct, this would operate only at the level of appearances and would result in a much larger amount of revenue to collect when the revenue requirement is affirmed in the next full rate case.

3. Q: What are the impacts of the decoupling mechanisms on low-income residential customers?

A: Since PSE does not have a special low-income rate design based on household ability to pay, low-income residential customers have the same rates as all residential customers (though with the possibility of partial payment assistance for qualifying customers). The impacts of the decoupling mechanisms on low-income residential customers are small to very small, individually, for each the three years examined.

We use the term "small" in a contextual way. A scan of Table I.1, across the decoupling groups suggests that most of the percentages would appear small under any definition. This is particularly true on the electric side. In a practical perspective, a small change is one in which a customer would not be likely to recognize an effect on monthly bills (given the large changes in the commodity cost of natural gas, the seasonality of energy used and the effect of short warming or cooling cycles). This is a "signal to noise" situation with a weak signal and a large amount of noise. For a rough approximation, any adjustment percentage of 3% or lower is considered small. Note that in Table I.1, those percentages larger than 3% are capped at 3% for the relevant rate. (Also, see the discussion of Effect Sizes towards the end of this section of the study.)

For electricity, the average Bill Assisted residential electric customer *used essentially the same*, but slightly more electricity than the average Non-Bill Assisted electric customer (see qualifications on this statement in Section IV). Since the deferral adjustment is applied to volumetric rates, Bill Assisted electric residential customers had slightly higher bills due primarily to higher use of electricity and also due to the small volumetric increment from the deferral adjustment. This pattern would occur if volumetric rates were increased with or without the decoupling mechanism. The slightly higher consumption levels of Bill Assisted customers could result from higher concentration of electric heating in this group or lower level of energy efficiency.

For gas, the usage curves for Bill Assisted and Non-Bill Assisted customers *are essentially identical*, though Bill Assisted customers used very slightly less (see qualifications on this statement in Section IV). This pattern suggests that there is no tendency at all to waste energy on the part of Bill Assisted gas customers.

With regard to assistance with energy bills, PSE low-income customers are provided bill payment assistance through grants from the federal Low-Income Housing Energy Assistance Program (LIHEAP), PSE HELP, Warm Home Fund, and from other sources including tribes, faith-based and government organizations. PSE can control the amount of PSE HELP, but the total of LIHEAP funding is decided each year by Congress and is then allocated to the states by formula. PSE has meaningfully increased dollars available for PSE HELP grants but this increase has been outpaced by a substantial decline in federal assistance dollars. Since 2013, the response to the assistance shortage has been to meet the needs of more households by awarding, on average, lower dollar-amount grants. Bill Assistance funds a smaller share of the low-income customer's bill than it did in past years due to federal assistance reduction, not to decoupling. The drop in federal support is a contextual factor in that would have happened with or without decoupling.

- Payment Assistance: There is a problem with a substantial decrease in assistance funding and a tendency to lower grant amounts while spreading coverage to more households. This would have happened with or without decoupling. While PSE has increased funding for HELP grants, the Congress has, by a substantially larger amount, cut funding for federal payment assistance (LIHEAP).

With regard to energy efficiency for Billing Assisted and Non-Billing Assisted customers, there was a substantial increase in Billing Assisted weatherization program funding (about 28%) from 2013 to 2014 that affected gas and electricity, relatively to the same degree. Pursuant to the Commission's Order, PSE increased annual billing-assistance funding for low-income customers by $1,000,000 (recurring each year during the term of the rate plan) plus the average increase in residential rates from Schedule 142. In addition, PSE increased funding for low-income residential weatherization by $500,000 (recurring each year during the term of the rate plan), plus a shareholder contribution of $100,000 per year. From 2014 to 2015, Billing Assisted gas funding dropped by about 27% while electric Billing Assisted funding increased about 7%. Due to the relative sizes of the electric and gas programs, this was an *overall increase* in Billing Assisted weatherization funding from 2014 to 2015 of about 3%.

In contrast, funding for regular residential energy efficiency programs increased about 5.5% for electricity and about 5% for natural gas. There were no major changes to the low-income weatherization program.

- Electric low-income funding for weatherization increased by 30% over the first two years examined and then remained consistent over the third year.[5]

- Gas low-income funding for weatherization increased by about 23% in the first year), but then decreased about 27% (see Table IV.21: through Table IV.22:) in the second year to return essentially to the pre-decoupling level. Gas funding has decreased due to decreased gas production at the agency level.[6]

- Electric non-low-income energy efficiency funding increased about 5.5% from 2014 to 2015.

- Gas regular residential funding increased by about 5% in the second year.

[5] Response to Data Request 30.43.

[6] Response to Data Request 30.43.

There were no structural modifications to low-income Bill Assistance programs during the three-year study.

For additional detail, please see Section IV.

4. Q: Are there conclusive trends in conservation program performance?

A: No. There is overall stability of good performance (energy efficiency and conservation achievement) in decoupling as compared with the time just prior to decoupling. There is no indication of a sizable change in electric conservation performance. Performance has been consistently good in relation to goals. Current data indicate that PSE meets the target of increasing conservation by 5% as required by the Commission.[7] Achievement has been good.

Decoupling is not neutral, but a positive step in that it removes barriers to energy conservation by increasing certainty of revenue recovery. However, it does not monetize the value of conservation in the form of incentives for the utility. There is a nuanced sense that it is OK to exceed program targets. Also, the support of regional gas market transformation may be considered a significant progressive adaptation. PSE's leadership and staff tend to support decoupling and see positive benefits. For additional detail, please see Section V.

- We find no problem in this area.

5. Q: Are there any adverse impacts associated with decoupling?

A: For all three years of decoupling, *we find no conclusive evidence to suggest that the decoupling mechanism has any adverse effects*:[8]

- The variation in cost caused by the adjustment mechanism is small.
- The adjustment mechanism does not negatively affect conservation.
- The idea that sales is the only motivator that can keep a utility bright and alert is not true; there are many strong motivators – other than sales – for doing good and careful work while also paying careful attention to goals and duty.

[7] The goal includes a requirement from the Amended petition (p. 17, paragraph 31) that PSE achieve electric conservation five percent above the biennial targets set by the Commission pursuant to the Energy Independence Act (RCW 19.285).

[8] We now have three Evaluation Years, so this is a stronger conclusion than it was in the first or the second year report.

- The fact that exceeding conservation targets is not an automatic concern of executive management may be considered a positive impact.[9]

- PSE's annual average increase in O&M costs has declined when compared to the historical growth rate presented in the decoupling rate plan proceedings under Docket Nos. UE-121697, et al.

However, for a single decoupling group, Residential Natural Gas (Schedules 23 & 53), *there is a concern*. The concern is that sometimes it may take a short span of years to achieve full revenue recovery. This was discussed in *Question & Answer 2*, (above) where we suggest that growing deferral balances be addressed by raising the Rate Test for (only) residential natural gas (Schedules 23 & 53) from 3% to 5%. This is approach is discussed in more depth in *Question & Answer 6* and is the focus of Section VII of this report. We do not see this lengthening of the timing for revenue recovery as an adverse consequence for two reasons: (a) the rate adjustment mechanism is working as designed and (b) the influential factor is weather, which is given by the natural environment.

We were surprised to find that, with a 3% cap, cumulating deferrals will not be unusual for a single, highly weather-sensitive, decoupling group. In a short warming cycle, a cumulating deferral might take three or four (or seven) years to get into the next cooling cycle in order to allow full revenue recovery. This situation has potentially concerning aspects:

a. Cumulating, or "snowballing" deferrals from year to year.

b. Some parties may be impatient for the warming and cooling cycles to balance out so that full revenue recovery occurs.

c. As a general regulatory concern, whenever recovery lags, there may be a small element of increased risk for full recovery.

d. Activation of a perceived conflict within the principles of the General Agreement on Accounting Principles (GAAP) occurs. One of the GAAP principles requires that deferred revenue be collected within two years to be recognized. When deferred revenue accumulates across additional years, this particular GAAP principle cannot be followed. Instead, a different GAAP principle may be followed –

[9] A commenter, in review of the study of the first Evaluation Year, suggested that conservation spending not be viewed as a measure of success because these costs are passed directly through to the customers via the Schedule 120 tariff ride and evaluation should take that into consideration. The evaluation team believes that continuation and/or increase in conservation spending is one of a set of indicators of success.

keeping the incurred obligation together with eventually realized revenue across years. These GAAP principles are inherently in tension with each other and it is ethically permitted to privilege one principle over another in a practical situation. Here, the two-year rule could be privileged or the rule for keeping incurred revenue obligation and realized revenue together (across years) could be privileged. We note that GAAP is simply a set of accounting conventions in internal tension with each other and that there are accepted work-arounds.

For a party that prioritizes a two-year limit on the length of time between sales and revenue recovery, any or all of these four aspects (the "snowballing" effect, the number of years required to achieve revenue recovery, the small possibility of increased regulatory risk and the need for a workaround to conventional GAAP rules) could be viewed as adverse effects.

Whether viewed as a fact of nature (weather moves in short warming cycles and short cooling cycles) or as an adverse consequence, cumulating deferral of revenue recovery is a fact documented in this evaluation.

Also, as a separate matter, there are four performance indicators that are out of range for 2015. We interpret this as due to weather events. However, these indicators should be watched for 2016 and 2017 to make sure they are one-time events.

For additional detail, please see Sections VI & VII.

6. Q: Given the occurrence of two years in which deferred revenue is increasing for the natural gas residential group (Schedules 23 & 53), when might the decoupling balance be expected to reach zero and what is the impact on rates to date and likely future rate impact from the natural gas residential group deferral balance?

A: This is a new section for the three-year evaluation, and provides the primary focus of this report. The answers are more complex than can be easily summarized. The one decoupled rate group where this is an issue is residential natural gas (Schedules 23 & 53). The next Schedule 142 rate adjustment will occur in May 2017. As of May 1, 2016, a total of $28,736,968 (Table VII.2) has been carried forward in the decoupling deferral account to be recovered in future periods. PSE estimates for the residential gas decoupling group, unamortized revenue due to the rate test will not be fully recovered until April 2018, and that in May 2017 the 3% soft cap will again be reached for residential natural gas customers.

For the detail, please see Section VI.

7. Q: Is there an impact on conservation achievements for customers on Schedules 26 & 31?

A: No. For the three years studied, conservation proceeded as “business as usual” for this sector. For additional detail, please see Section VIII.

- We find no problem in this area.

Effect Sizes

Throughout this study, conclusion statements are made that effects of decoupling are “small” or “very small”. These terms are referenced to analyze contexts in which monthly bills have high month-to-month (and cycle of years) variations, sometimes punctuated by background factors such as a change in the commodity cost of natural gas.

There are, by analogy, generally accepted conventions on effect size in statistical analysis.[10] These are dependent on the particular statistic in use and on the field of application; these conventions may differ in special cases based on the specific nature of a particular investigation. Yet the conventions are useful in statistical practice. In this study, we are not usually using statistics, such as values of “t” or correlation or regression coefficients, but we are typically thinking of an effect as a percentage. We need to understand the size of an effect in relation to other sources of percentage change that influence results. The question, then, is whether a certain percentage is small, medium or large. From that structure, we can infer what slight or very large might mean.

Also, when dealing with rates or bills we note that over time, and with or without decoupling, the revenue requirement tends to increase. This is recognized, for example, in the 3% cap on the overall change for a rate each May 1st. Though most rates do not change this much, a rate representing cumulative change across years does: After three years, a 3% adjustment per year would be slightly above 9% on a cumulative basis. Changes need to be considered both as specific to a particular year and, separately, as cumulative change across years.

[10] For a presentation of statistical effect sizes, see: Cohen, Jacob, *Statistical Power Analysis for the Behavioral Sciences*, Second Edition. Hillsdale, New Jersey: Lawrence Erlbaum Associates, Publishers, 1988

Most Schedule 142 rate adjustments are less than 3% (they cannot be more than 3% for a given year due to the operation of the cap). A 3% change in an overall rate in a given year is small. We call this change "small" because bills generated by that small change in rate will likely not be discernable from normal background variation to a customer.

This background variation can consist of many factors. For residential decoupling groups, it is the noise of seasonal variation and it is the noise of short weather cycles for decoupling groups that are weather-sensitive. Without considering month-to-month variation linked to seasonality, residential natural gas (Schedules 23 & 53) bills vary by about +/-8% over short ranges of years. This is due simply to the difference between actual weather and conventional "normal" weather. Within that background variation and the way seasonality distributes bills over months, 3% is small and unlikely to be noticed by most customers. Residential natural gas bills also vary due to other factors. In particular, the commodity cost of gas produces large variations in bills. Changes up and down in commodity cost of gas produces large percentage swings in gas bills that dwarf weather effects. So, considered against this background variation, decoupling effects of 1%, 2% or 3% are small.

Cumulative change, a little over 9% in three years or more than 15% at the extreme of five years, is not small in relation to seasonality or to short weather cycles. For looking at cumulative change across years, we define from just over 3% to under 10% as a medium effect. At or over 10% is defined as a large effect.

Revenue Requirement

What is seen here is the operation of a revenue requirement as translated through the adjustment mechanism. We take the revenue requirement to be a real number in the real world that is approximated in the adjustment mechanism. The revenue requirement approximated through the adjustment mechanism would otherwise be approximated through another process (for example, in a traditional rate case). In this perspective any set of sound approximation approaches would each approach the correct revenue requirement (the same number). Put another way, any well-designed alternative approach would produce a very similar approximation to the same revenue requirement.

Statement of High-Level Results

The high-level results of the study are stated here. For the three years examined:

(1) We find that the decoupling mechanism worked as intended. The control tool that limits overall rate increase for a decoupling group (set of rate schedules) worked as planned, limiting rates and deferring unrealized revenue recovery to a future year. The earning test tool also worked exactly as planned, returning funds to customers when there was an over-collection.

(2) There was a surprise: For a single natural gas decoupling group with high sensitivity of energy usage in relation to temperature (residential natural gas – Schedules 23 & 53), full recovery of automatically deferred revenue was not complete within two years. Deferral went into a second year and appeared likely to go into a third. PSE estimates that, for the residential gas decoupling group, the $8.7 million in unamortized revenue due to the rate test will not be fully recovered until April 2018. This occurred due to the operation of the cap at the three percent (3%) level and the nature of the weather – warming occurs in short warming cycles across years. Years are not independent of each other for warming and cooling. The mechanisms of the pilot worked exactly as planned, but unrealized revenue crossed more than two years. This cumulative effect is a simple function of the level of the cap and a typical warming cycle.

(3) Four performance indicators are out of range for 2015. We interpret this as due to weather events. However, these indicators should be watched for 2016 and 2017 to make sure they are one-time events.

(4) Although theoretical concerns about bill increases and the motivation to do good work are sometimes raised in the planning phase for decoupling, we did not find these to be operative in the three years studied.

(5) In this case study, decoupling is a careful and incremental reform with positive features, such as increasing the surety of revenue recovery and removing potential barriers to conservation. (As conservation was already good prior to decoupling, we did not detect a difference.) It supports an organizational reality in which it is acceptable for staff to exceed saving goals and in which DSM is part of a positive organizational outlook.

(6) However, though decoupling removes barriers, it does not create a "demand-pull." There is no "pulling force" because it does not have the "Decoupling 2.0"[11] monetization of incentives for the utility.

[11] Decoupling 2.0 is a shorthand way that people working on evaluation of decoupling refer to the addition to the decoupling mechanism of one or more reliable new revenue streams for the utility for meeting or surpassing energy efficiency and conservation (and possibly including distributed energy resource, demand control or micro-grid) goals. These goals could be of any type. The critical concept is to create a "demand-

(7) The size of the decoupling adjustment each year, for each decoupling group over the three years studied, is small: small enough so as not to influence customer energy conservation; small enough to be within general customer experience of normal energy cost variations due to seasonality and weather cycles from year to year.

(8) The size of the cumulative decoupling adjustment for a set of warm years for the residential natural gas (Schedule 23 & 53) group (and only for this one group) will increment from 3% to 6%, 9%, 12%, and 15%, etc., depending on the span of the short warming cycle. Then, during the following cooling cycle, the deferred revenue will be collected and, if the cooling cycle continues, the adjustment mechanism will eventually reset.

(9) If households have insufficient income, they will have trouble with energy bills. PSE HELP funding is essential. Federal low-income support is also very important but is erratic as to amount and timing. In every customer class, customers who use more energy will have higher energy bills and customers who use less energy will have lower energy bills. This reality is independent of decoupling. To bring bills into line with household ability to pay, decoupling is not an answer. PSE would need to consider a low-income rate based on ability to pay.

(10) *Decoupling works*. Generally, PSE decoupling operated as expected. However, it was expected that deferred revenue would be amortized within one year after the year in which the energy was delivered to the customer, causing transactions to balance within two years. For the natural gas residential group (Schedules 23 & 53), deferred revenue accumulated from the second to the third year. We suggest that the potential problem of growing deferral balances be addressed by raising the Rate Test from 3% to 5% for the residential natural gas decoupling group only. Otherwise the cap can remain at 3%. We find that the decoupling mechanism worked as intended. The control tool that limits overall rate increase for a decoupling group (set of rate schedules) worked as planned, limiting rates and deferring unrealized revenue recovery to a future year. The earning test tool

pull" that creates a continuing revenue stream by monetizing some of the values attached to the goals. In discussion about decoupling, the kind of decoupling in play for PSE for the time window studied would be called "Decoupling 1.0". Though the K-factor is an add-on, it does move the mechanism to Decoupling 2.0. If values of energy efficiency and conservation (and possibly including micro-girds, distributed energy resources and demand control) were partially monetized to create one or more reliable and continuing payment streams to the utility, we would call the combined package "Decoupling 2.0".

also worked exactly as planned, returning funds to customers when there was an over-collection.

Naming Convention for Data Requests

The data used in this study was provided by PSE in response to many Data Requests (DRs) from H. Gil Peach & Associates. All DRs that begin with a number less than twenty belong to the first Evaluation Year. All DRs that begin with the number twenty belong to the second Evaluation Year (for example, DR 20.01). All DRs that begin with the number 30 (for example, DR 30.34) belong to the three-year evaluation. Additionally, the second part of the DR number for the three-year evaluation usually keys from the same number in the second year evaluation when the request is for an update from a previously asked question.

Time Included in Sections of the Study

We define the first evaluation year as running from July 1, 2013 through June 30, 2014. The second evaluation year runs from July 1, 2014 through June 30, 2015. The third evaluation year runs from July 1, 2015 through June 30, 2016. The decoupling rate first appeared on customer bills as the K-factor with July 2013 bills. In May 2014, the first deferral adjustment was applied (the K-factor is taken into account within this adjustment and subsequent adjustments) and customers experienced this rate through the end of April 2015. On May 1, 2015, the second deferral adjustment was in place on customer bills. On May 1, 2016, the third deferral adjustment was in place on customer bills.

PSE posted all data requests to *Basecamp*, a secure electronic project management website. Interested parties to this evaluation are provided access to *Basecamp*, and may query all data requests and responses at their convenience. PSE reviewed section drafts as they were completed, sometimes along with authorized *Basecamp* users. PSE's Conservation Resource Advisory Group (CRAG) members also received a draft first-year report and a draft second-year report, on which some members made comments. This three-year report includes our consideration of these comments. The draft study was presented to the CRAG in early December 2016 and improved using comments at the meeting and comments submitted by the parties afterwards.

Figure I.1 shows how Evaluation Years and Rate Years fit together. Cycles for billing assistance, program achievement review (the Biennial Electric Conservation Achievement Review or “BECAR”) and other programs follow their own yearly definitions and are only approximately matched with the decoupling program cycles. *In each section, it is best to look for specification of the months covered.*

Rate Years and Evaluation Years

Year 1

Calendar 2013							Calendar 2014					
May	**Jun**	**Jul**	**Aug**	**Sep**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
		First Rate Year (10 months): K-factor only										
		First Evaluation Year										

Year 2

Calendar 2014							Calendar 2015					
May	**Jun**	**Jul**	**Aug**	**Sep**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Second Rate Year (12 months): First Deferral Applied												
		Second Evaluation Year										

Year 3

Calendar 2015							Calendar 2016					
May	**Jun**	**Jul**	**Aug**	**Sep**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
Third Rate Year (12 months): Second Deferral Applied												
		Third Evaluation Year										

Note 1: Each year evaluation runs from July 1 through June 30 of the following year.
Note 2: The first rate year runs from July 1, 2013 through April 30, 2014.
Note 3: The second and third rate years run from July 1 though April 30 of the following year.

Figure I.1: Evaluation Year and Rate Year.

Section Summary

This section of the study summarizes the results and provides high-level answers to the primary research questions. It also provides an introduction to the evaluation.

We find that the PSE decoupling works. However, performance indicators should be watched for 2016 and 2017.

Cumulating deferrals for the residential natural gas decoupling group (Schedules 23 & 53) surfaced as a primary interest in the study. Cumulating deferrals for this group are related to the size of the overall rate cap (3% for the pilot) in interaction with weather – specifically short warming cycles of from one to seven years.

We recommend the cap be adjusted to 5% for the residential natural gas decoupling group (Schedules 23 and 53) only. We find that the 3% cap is working well for all other decoupling groups.[12]

[12] A study of electric decoupling conducted by the Regulatory Assistance Project notes that "Although reconciliation adjustments resulting from a revenue adjustment mechanism tend to cluster in the −2 to +3 percent range, they can be larger or smaller, as either a surcharge or credit." Migden-Ostrander, J., and Sedano, R. (2016). *Decoupling Design: Customizing Revenue Regulation to Your State's Priorities.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities. In the current study, all but one electric adjustment is under the 3% cap, and the deferred revenue from that single case was realized in the following year. Similarly, in the current study the non-residential gas decoupling group showed annual adjustments under 3%. We suggest that if most adjustments are under 3% for electricity, then a 3% cap should be workable for electricity. And, based on results here (where there was a meaningful warm weather cycle), a 3% cap is reasonable for non-residential natural gas.

II. Calculation of Rates and Deferrals

The first task in the evaluation (Figure II.1) is to check calculations for conformance to the Commission Order approving decoupling. There are two steps in this first evaluation item in the Amended Petition. The first step is to determine whether the calculations are correctly carried out. The second step is to validate the credibility of the source data.

Task Element 1: Examine Deferrals and Rates

An audit of whether the deferrals and rates were calculated in accordance with the Commission order approving the decoupling mechanisms and subsequent orders approving corrections to the decoupling rate calculations.

Figure II.1: Check Calculations

Is the Math Correct? Yes.

The first step in determining whether the deferrals and rates were calculated in accordance with the Commission orders approving the decoupling mechanisms is to compare the calculations and methodologies embedded in the spreadsheets submitted by PSE in the 2014 Electric Decoupling Filing Effective May 1, 2014 to the methodologies described in the Commission orders. PSE provided the evaluation team with fifteen relevant spreadsheets in response to Data Requests 30.07, 20.07 and 1.05. The calculations in these spreadsheets were compared to the relevant Washington Utilities and Transportation Commission (WUTC) decoupling dockets, including WUTC Order 07, WUTC Order 09, Attachment A Electric Revenue Decoupling Mechanism and Attachment B Gas Revenue Decoupling Mechanism found in Dockets UE-121697 and UG-121705 Amended Petition for Decoupling Mechanisms as submitted to WUTC by PSE (February 28, 2013).

The comparison included calculations embedded in the following workbooks (file name “121697-UE 121705-UG PSE Resp GIL PEACH & ASSOC” followed by the “DATA REQUEST” number and attachment numbers listed in parenthesis):

- Workbook used to calculate electric and gas decoupling deferrals, July 2013 – June 2016:

1. (Data Request 30.07_Attachment A)

- Workbooks used to calculate decoupling rates, effective May 1, 2016:

2. Electric (Data Request 30.07_Attachment B)

3. Gas (Data Request 30.07_Attachment C)

- Workbooks used to calculate decoupling rates, effective May 1, 2015:

4. Electric (Data Request 20.07_Attachment B)

5. Gas (Data Request 20.07_Attachment C)

- Workbooks used to revise the allowed revenue per customer to place schedule 10 and 12 customers in the correct decoupling group, effective July 1, 2014:

6. Electric non-residential (Data Request 01.05_Attachment I)

7. Electric schedules 26 & 31 (Data Request 01.05_Attachment J)

- Workbook used to calculate change to electric decoupling rates to place schedule 10 and 12 customers in the correct decoupling group, effective July 1, 2014:

8. (Electric Data Request 01.05_Attachment K)

- Workbooks used to calculate change to decoupling rates, effective May 1, 2014:

9. Electric (Data Request 01.05_Attachment G)

10. Gas (Data Request 01.05_Attachment H)

- Workbooks used to calculate change to decoupling rates, effective January 1, 2014:

11. Electric non-residential (Data Request 01.05_Attachment D)

12. Electric schedules 26 & 31 (Data Request 01.05_Attachment E)

13. Gas (Data Request 01.05_Attachment F)

- Workbooks used to calculate decoupling rates, effective July 1, 2013:

14. Electric (Data Request 01.05_Attachment B)

15. Gas (Data Request 01.05_Attachment C)

Based upon our analysis of the embedded calculations in the spreadsheets, the calculations used by PSE to calculate deferral and rate adjustments replicate the mechanisms described in the WUTC decoupling orders. This opinion applies to data through June 2016, which is the end of the period for Year 3 of the Evaluation. Within Worksheets I and J, PSE corrects a customer count error in Worksheets D and E. This error places certain PSE customers, those who are eligible to receive Residential Exchange Credits from the Bonneville Power Administration, in the wrong decoupling group. A total of twenty-nine customers (fifteen customers in Schedule 10 and fourteen customers in Schedule 12) are removed from the electric non-residential group and placed in the correct decoupling groups. Worksheet K revises the electric decoupling rates effective July 1, 2014 to correct this error.

On April 22, 2015, the WUTC approved PSE's request to change its methodology for calculating decoupling deferrals going forward to exclude the amortization of prior deferrals from the calculation of "actual revenue," effective May 1, 2015. In addition, the WUTC also approved PSE's request to adjust the May 2014 through April 2015 deferrals to equate with the new methodology. Attachment A, provided in PSE's response to DR 20.07 and DR 30.07, represents the restated results.

Is the Source Data Credible? Yes.

The second step in completing the calculations audit is to validate the credibility of the test period costs and revenues, load projections, and other company financial data. Since this data was audited by a professional audit team (Price Waterhouse) that provides an opinion regarding the accuracy of the data, we are relying on their professional opinion to validate the financial integrity of the data.

Attachments A and B to PSE's Response to H. Gil Peach & Associates Data Request No. 01.38 continue to be the current accounting instructions used to guide the implementation, tracking and ongoing review of PSE's electric and gas decoupling mechanisms.

The Price Waterhouse "Report of Independent Registered Public Accounting Firm" for the twelve-month period ending December 31, 2015 is shown as Figure II.2[13]. Price Waterhouse also provided their financial audit opinions of PSE's reported financial statements for calendar years 2014[14] and 2013[15], as shown in Figure II.3 and Figure II.4.

[13] Response to Data Request 30.08, Attachment A.

[14] Response to Data Request 20.08, Attachment A.

[15] Note that the financial audit opinion provided by Price Waterhouse reports on a period ending December 31, 2013, which includes the first six months of the Evaluation year plus the second six months of the prior year. The opinions presented in Figures 2, 3 and 4 the cover the three-year evaluation period through December 31, 2015. The last six months of the three-year evaluation period, January 2016 through June 2016, will be addressed in an audit opinion report in 2017, after the required deadline for this evaluation report.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Puget Sound Energy, Inc.

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Puget Sound Energy, Inc. and its subsidiary at December 31, 2015 and December 31, 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 13 to the consolidated financial statements, in 2015 the Company changed the manner in which deferred tax assets and liabilities are classified on the balance sheet.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Seattle, Washington
February 26, 2016

Figure II.2: 2016 Financial Audit Opinion for 2015 – DR 30.13

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Puget Sound Energy, Inc.

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Puget Sound Energy, Inc. and its subsidiary at December 31, 2014 and December 31, 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Seattle, Washington
February 27, 2015

Figure II.3: 2015 Financial Audit Opinion for 2014 – DR 20.08

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Puget Sound Energy, Inc.

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Puget Sound Energy, Inc. and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control on Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Seattle, Washington
March 13, 2014

Figure II.4: 2014 Financial Audit Opinion for 2013 – DR 1.38

Section Summary

Based on our analysis of three years of data, we conclude that Puget Sound Energy has calculated rates and deferrals in accordance with the Commission Order approving the decoupling mechanisms for the first through the third Evaluation Years.

III. Evaluation by Each Cost of Service Category

The second evaluation task in the Amended Petition is to study impacts of decoupling by cost of service (COS) category. We report actual results first for electricity; then for natural gas based on the directive expressed for Task Element 2 (Figure III.1).[16] In addition to actual billed revenue, results for a standardized residential customer with monthly usage pre-specified as 1,100 kWh and 68 therms are reported in Section XIII (Typical Residential Bills).

> **Task Element 2: Examine Tariff Tracker Adjustments**
>
> An evaluation of the impacts of the decoupling tariff tracker adjustments, calculated in relation to energy sales (kWh or therms), as a percent of monthly bills, and in total dollars for each rate category customarily used for purposes of PSE's cost of service analyses.

Figure III.1: Examine Impacts by Cost of Service Group

Impacts of tariff tracker adjustments included in WUTC Orders 07 and 09 are the combined effect of the K-factor adjustment and the true-up of decoupling deferrals. These two components are the decoupling rate (Schedule 142 surcharge) applied to units of energy (kWh or therms) or demand (kW) sold.

- Some Cost of Service customer classes are only subject to the automatic, multi-year rate adjustment component of Schedule 142 (the K-factor).
- The Schedule 142 rates of most COS classes also include the decoupling deferral adjustment.

The tables that follow show those Cost of Service classes that are subject to each of the two provisions of Schedule 142. In Table III.1, seven of the ten Electric COS classes shown are subject to the decoupling deferral component of Schedule 142. We focus on these classes.

[16] Analysis in this section of the study is based on DR 30.35 Attachments A & B.

Table III.1: Electric Cost of Service Classes – DR 1.06

		Schedule 142 Component	
Cost of Service Class	**Rate Schedules**	**K-factor**	**Decoupling Deferral**
Secondary Voltage - Small (Residential)	7	Yes	Yes
Secondary Voltage - Small (Non-Residential)	8, 24	Yes	Yes
Secondary Voltage - Medium	7A, 11, 25, 29	Yes	Yes
Secondary Voltage - Large	12, 26	Yes	Yes
Primary Voltage Class	10, 31, 35, 43	Yes	Yes
Campus Rate Class	40	Yes	Yes
High Voltage Class	46, 49	Yes	Yes
Street & Area Lighting Class	50-59	Yes	No
Transportation Class	449, 459	Yes	No
Firm Resale Class	5	No	No

In Table III.2, four of the eight natural gas COS classes are subject to the decoupling deferral component of Schedule 142. We focus on these classes.

Table III.2: Gas Cost of Service Classes – DR 1.06

		Schedule 142 Component		
Cost of Service Class	**Rate Schedules**	**K-factor**	**Decoupling Deferral**	**Notes**
Residential	23, 53, 16	Yes	Yes	(a)
Commercial & Industrial Class	31, 31T, 61	Yes	Yes	
Large Volume Class	41, 41T	Yes	Yes	
Interruptible Class	85, 85T	Yes	No	(b)
Limited Interruptible Class	86, 86T	Yes	Yes	
Non-Exclusive Interruptible Class	87, 87T	Yes	No	(b)
Contracts Class	Special Contracts	No	No	
Rentals Class	71G, 72G, 74G	Yes	No	

(a) Rate Schedule 16 is not subject to the decoupling deferral but is included in the Residential COS class and therefor in our analysis by COS class.

(b) Effective May 1, 2015, gas schedules 85, 85T, 87 and 87T are no longer subject to true-up charges related to the decoupling deferral and are only subject to the K-factor

Electric COS Classes

Table III.3 shows the Schedule 142 volumetric surcharge by Cost of Service class subject to the decoupling deferral. Over $136 million was collected from these COS classes through the Schedule 142 surcharge from July 2013 through June 2016. The largest contributor was Residential. The Residential class accounted for $89.1 million or sixty-five percent (65%) of Schedule 142 revenues. Schedule 142 revenues amounted to just under three percent (2.8%) of the total revenue from Residential customers (Table III.3, Line 1), adding $92 to the average residential bill over three years (or $31/year).

Taken together, Small Non-Residential and Medium Secondary Voltage customers paid nearly $31 million in Schedule 142 surcharge, which is equal to 23% of total dollars collected through Schedule 142 over three years. However, the effect of Schedule 142 on overall revenue is relatively small. Over the three years, Schedule 142 comprised about two percent of the electric bill for each of these classes. The Schedule 142 surcharge for all other classes for the three years examined ranged from just under one percent to 2.6% of class revenue.

Table III.3: Electric COS Class Revenue Impacts of Schedule 142 (7/2013 through 6/2016) – DR 30.35

ELECTRICITY (Three Years)							
				Schedule 142 Surcharge			
PSE Cost of Service Class	**Rate Schedules**	**Number of Customers (Average Monthly)**	**Total Billed Revenue**	**Revenue**	**Percent of Total Revenue**	**Per Customer**	**Per Customer Per Year**
Secondary Voltage - Small (Residential)	7	966,388	$3,182,356,912	$89,110,875	2.8%	$92	$31
Secondary Voltage - Small (Non-Residential)	8, 24	114,424	$852,180,991	$15,187,693	1.8%	$133	$44
Secondary Voltage - Medium	7A, 11, 25, 29	7,631	$851,804,548	$16,000,427	1.9%	$2,097	$699
Secondary Voltage - Large	12, 26	779	$516,752,829	$5,707,018	1.1%	$7,328	$2,443
Primary Voltage Class	10, 31, 35, 43	633	$374,268,641	$3,305,105	0.9%	$5,218	$1,739
Campus Rate Class	40	130	$155,871,553	$3,609,714	2.3%	$27,826	$9,275
High Voltage Class	46, 49	25	$137,129,820	$3,568,405	2.6%	$141,479	$47,160
Totals		**1,090,011**	**$6,070,365,294**	**$136,489,237**	**2.2%**	**$125**	**$42**

While reasons vary for the differences in the percentage impact of Schedule 142 shown in Table III.3, the mathematics of decoupling identify two primary drivers. Differences in Schedule 142 revenue as a percent of total revenue between COS classes are driven by differences in trends of use per customer and differences in growth in the number of customers. Higher use per customer, with all other things equal, results in downward pressure on future decoupling rate adjustments. Likewise, lower use per customer results in upward pressure on future decoupling rate adjustments. Differences in customer growth within a COS class can also put upward or downward pressure on decoupling rates. Faster growth from larger customers than smaller customers within the same COS class results in upward pressure on use per customer and therefore downward pressure on future decoupling rate adjustments.

To better understand differences in Schedule 142 impacts between COS classes, it is necessary to examine several factors embedded in the decoupling mechanism. These factors include the impact of trending use per customer, K-factor, deferral adjustments, deferral account balances and the soft cap on rates. This report reviews the impact of these factors in Section VII.

Monthly Impacts of Decoupling Tariff Tracker Adjustments (Electric)

Monthly usage and Schedule 142 surcharge impacts, per customer, over the first through third Evaluation Years are shown in Table III.4, Table III.5, and Table III.6, respectively. Monthly revenue impacts follow the pattern of volumetric sales. As a result, customer classes with high seasonality also show high seasonality in the average customer's monthly Schedule 142 charge (see Residential COS class in Figure III.2).

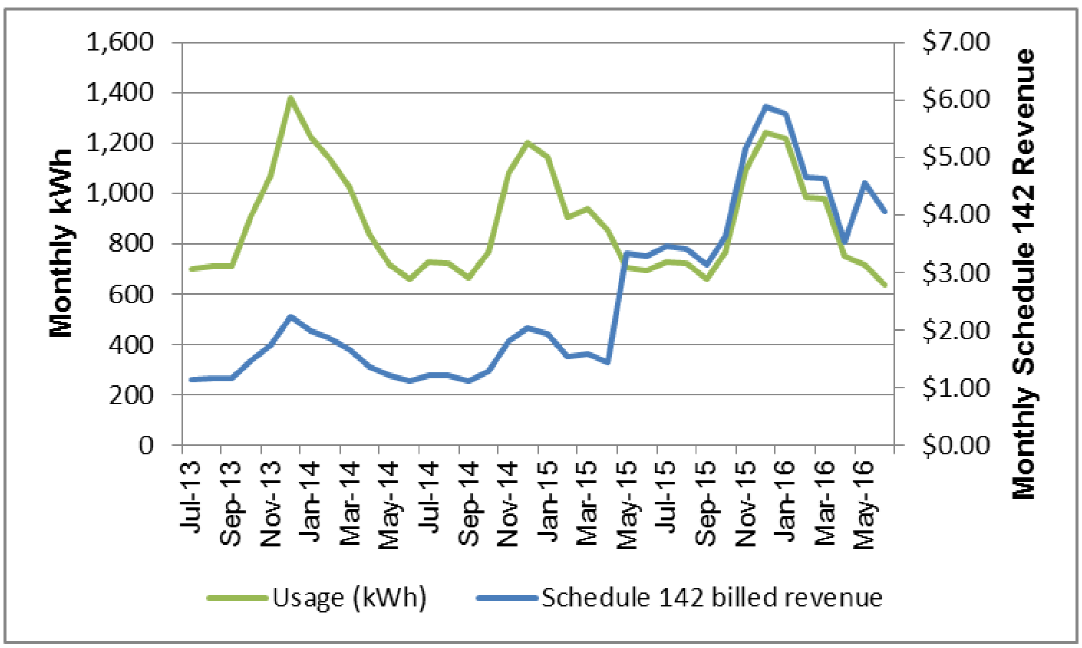


Figure III.2: Residential Electric COS Class Monthly Usage and Schedule 142 Bill – DR 30.35

Due to a class' high seasonality and following the pattern of volumetric sales, the surcharge paid per customer varies significantly by month for the Small-Residential class, ranging from a low of $1.11 per customer in June of 2014 to a high of $5.88 per customer in December 2015.

A review of the monthly data in Table III.4, Table III.5 and Table III.6 shows that the percentage impact of Schedule 142 on total revenue tends to be relatively constant from month-to month. The months of May and June can be exceptions and show significant differences in Schedule 142 revenue percentage from preceding months. This is due to the May 1 effective date of new Schedule 142 rate adjustments. For example, the Schedule 142 percent for the High Voltage class jumped from 2.0% in April 2015 to 4.8% in May 2015.

Table III.4: Electric COS Class Monthly Impacts of Schedule 142 (7/13 through 6/14) – DR 30.35

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
Secondary Voltage - Small (Residential)												
Usage (kWh)	698	713	710	906	1,069	1,379	1,225	1,141	1,024	836	716	660
Billed revenue	$74	$76	$75	$93	$109	$141	$126	$118	$105	$86	$75	$65
Schedule 142 billed revenue	$1.14	$1.16	$1.16	$1.48	$1.74	$2.24	$1.99	$1.86	$1.67	$1.36	$1.21	$1.11
Percent of average monthly bill	1.5%	1.5%	1.5%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.7%
Secondary Voltage - Small (Non-Residential)												
Usage (kWh)	1,784	1,863	1,865	1,867	2,095	2,342	2,186	2,029	2,100	1,821	1,810	1,766
Billed revenue	$187	$194	$194	$199	$220	$244	$228	$214	$221	$188	$190	$185
Schedule 142 billed revenue	$0.60	$0.63	$0.63	$0.63	$0.71	$0.75	$0.77	$0.68	$0.71	$0.61	$2.44	$2.32
Percent of average monthly bill	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	1.3%	1.3%
Secondary Voltage - Medium												
Usage (kWh)	30,915	32,175	32,088	33,694	30,004	33,109	34,219	30,067	34,800	29,438	30,895	29,526
Billed revenue	$2,925	$2,971	$2,965	$3,417	$3,067	$3,393	$3,412	$3,119	$3,520	$2,714	$2,910	$2,798
Schedule 142 billed revenue	$10	$11	$11	$11	$10	$11	$12	$10	$12	$10	$41	$39
Percent of average monthly bill	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	1.4%	1.4%
Secondary Voltage - Large												
Usage (kWh)	246,161	236,733	216,811	210,639	187,269	224,375	180,963	181,468	215,979	199,339	191,417	212,688
Billed revenue	$21,105	$20,099	$18,842	$19,934	$17,480	$20,754	$17,162	$17,548	$20,234	$16,253	$16,405	$18,344
Schedule 142 billed revenue	$83	$80	$73	$71	$63	$76	($53)	($57)	($63)	($59)	$35	$176
Percent of average monthly bill	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	-0.3%	-0.3%	-0.3%	-0.4%	0.2%	1.0%
Primary Voltage Class												
Usage (kWh)	169,323	212,026	188,560	187,254	179,584	217,543	187,620	150,446	216,775	201,984	151,498	201,689
Billed revenue	$15,234	$17,790	$16,001	$17,495	$16,404	$18,698	$17,287	$14,366	$20,047	$16,891	$12,793	$16,741
Schedule 142 billed revenue	$57	$71	$64	$63	$61	$73	($62)	($66)	($90)	($86)	($27)	$31
Percent of average monthly bill	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	-0.4%	-0.5%	-0.5%	-0.5%	-0.2%	0.2%
Campus Rate Class												
Usage (kWh)	430,636	505,805	465,421	464,324	384,757	477,271	477,345	348,295	469,899	411,742	384,083	512,601
Billed revenue	$36,573	$39,345	$36,955	$28,757	$30,201	$36,100	$35,954	$27,346	$36,332	$31,603	$29,671	$40,395
Schedule 142 billed revenue	$145	$170	$157	$156	$130	$161	$161	$117	$158	$139	$533	$674
Percent of average monthly bill	0.4%	0.4%	0.4%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	1.8%	1.7%
High Voltage Class												
Usage (kWh)	3,090,23	2,019,193	2,216,27	2,527,57	1,752,25	2,217,63	1,930,62	3,239,645	298,208	2,330,573	2,278,312	1,533,43
Billed revenue	$215,336	$142,269	$153,111	$170,842	$129,388	$146,135	$134,977	$211,114	$41,422	$161,007	$160,736	$116,693
Schedule 142 billed revenue	$1,041	$680	$747	$852	$591	$747	$651	$1,092	$100	$785	$3,338	$2,015
Percent of average monthly bill	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.2%	0.5%	2.1%	1.7%
All COS Classes Subject to Schedule 142 Deferral												
Usage (kWh)	1,435	1,467	1,433	1,616	1,706	2,098	1,898	1,769	1,714	1,500	1,365	1,346
Billed revenue	$141	$142	$140	$160	$170	$208	$190	$178	$172	$144	$134	$128
Schedule 142 billed revenue	$1.28	$1.31	$1.30	$1.58	$1.80	$2.28	$1.89	$1.75	$1.56	$1.28	$1.77	$1.77
Percent of average monthly bill	0.9%	0.9%	0.9%	1.0%	1.1%	1.1%	1.0%	1.0%	0.9%	0.9%	1.3%	1.4%

Table III.5: Electric COS Class Monthly Impacts of Schedule 142 (7/14 through 6/15) – DR 30.35

	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
Secondary Voltage - Small (Residential)												
Usage (kWh)	726	721	667	768	1,083	1,202	1,147	905	940	853	707	695
Billed revenue	$71	$71	$66	$75	$105	$79	$114	$89	$92	$84	$68	$76
Schedule 142 billed revenue	$1.22	$1.21	$1.12	$1.29	$1.82	$2.03	$1.93	$1.53	$1.58	$1.44	$3.34	$3.29
Percent of average monthly bill	1.7%	1.7%	1.7%	1.7%	1.7%	2.5%	1.7%	1.7%	1.7%	1.7%	4.9%	4.3%
Secondary Voltage - Small (Non-Residential)												
Usage (kWh)	1,965	1,977	1,845	1,839	2,076	2,219	2,094	1,812	2,038	1,863	1,768	1,932
Billed revenue	$204	$205	$193	$198	$220	$161	$229	$194	$217	$193	$181	$207
Schedule 142 billed revenue	$2.58	$2.60	$2.42	$2.42	$2.73	$2.92	$2.75	$2.38	$2.68	$2.45	$6.09	$6.66
Percent of average monthly bill	1.3%	1.3%	1.3%	1.2%	1.2%	1.8%	1.2%	1.2%	1.2%	1.3%	3.4%	3.2%
Secondary Voltage - Medium												
Usage (kWh)	34,110	33,243	29,687	31,007	30,478	33,491	32,127	29,716	31,844	30,931	29,754	31,892
Billed revenue	$3,179	$3,083	$2,803	$3,238	$3,218	$2,623	$3,336	$3,091	$3,278	$2,801	$2,732	$3,103
Schedule 142 billed revenue	$45	$44	$39	$41	$40	$44	$42	$39	$42	$41	$103	$110
Percent of average monthly bill	1.4%	1.4%	1.4%	1.3%	1.2%	1.7%	1.3%	1.3%	1.3%	1.5%	3.8%	3.5%
Secondary Voltage - Large												
Usage (kWh)	241,420	202,674	191,864	204,611	181,484	196,740	221,546	188,748	203,275	201,303	194,225	232,079
Billed revenue	$20,580	$17,501	$16,450	$19,664	$17,695	$15,261	$21,065	$18,488	$19,111	$16,063	$16,430	$19,700
Schedule 142 billed revenue	$115	$106	$103	$103	$98	$100	$113	$107	$98	$93	$361	$394
Percent of average monthly bill	0.6%	0.6%	0.6%	0.5%	0.6%	0.7%	0.5%	0.6%	0.5%	0.6%	2.2%	2.0%
Primary Voltage Class												
Usage (kWh)	200,426	189,701	148,258	199,539	154,649	188,005	224,248	177,604	198,244	193,385	157,395	185,552
Billed revenue	$16,382	$14,686	$13,538	$18,273	$14,563	$13,895	$19,860	$17,107	$17,573	$15,571	$12,881	$15,402
Schedule 142 billed revenue	($79)	($49)	($86)	($71)	($57)	($58)	($61)	($69)	($57)	($61)	$302	$331
Percent of average monthly bill	-0.5%	-0.3%	-0.6%	-0.4%	-0.4%	-0.4%	-0.3%	-0.4%	-0.3%	-0.4%	2.3%	2.1%
Campus Rate Class												
Usage (kWh)	484,829	470,407	368,802	521,852	234,994	434,354	520,632	385,879	467,738	431,413	368,953	363,776
Billed revenue	$38,922	$36,881	$29,218	$38,866	$20,403	$28,093	$40,428	$30,598	$36,272	$32,845	$28,761	$29,237
Schedule 142 billed revenue	$637	$618	$485	$686	$309	$571	$684	$507	$615	$567	$1,271	$1,254
Percent of average monthly bill	1.6%	1.7%	1.7%	1.8%	1.5%	2.0%	1.7%	1.7%	1.7%	1.7%	4.4%	4.3%
High Voltage Class												
Usage (kWh)	2,770,588	2,330,80	2,768,68	1,563,31	3,258,714	1,094,46	1,938,632	2,500,340	1,420,74	2,022,956	2,443,456	2,185,258
Billed revenue	$190,287	$158,329	$193,575	$118,333	$227,234	$48,095	$137,362	$181,737	$100,694	$132,221	$175,972	$159,643
Schedule 142 billed revenue	$3,641	$3,063	$3,638	$2,054	$4,282	$1,438	$2,547	$3,285	$1,867	$2,658	$8,420	$7,530
Percent of average monthly bill	1.9%	1.9%	1.9%	1.7%	1.9%	3.0%	1.9%	1.8%	1.9%	2.0%	4.8%	4.7%
All COS Classes Subject to Schedule 142 Deferral												
Usage (kWh)	1,504	1,450	1,328	1,453	1,713	1,858	1,854	1,539	1,615	1,520	1,351	1,410
Billed revenue	$141	$136	$127	$142	$167	$129	$183	$152	$158	$141	$125	$141
Schedule 142 billed revenue	$1.87	$1.85	$1.69	$1.85	$2.35	$2.55	$2.48	$2.04	$2.13	$1.97	$5.10	$5.18
Percent of average monthly bill	1.3%	1.4%	1.3%	1.3%	1.4%	2.0%	1.4%	1.3%	1.3%	1.4%	4.1%	3.7%

Table III.6: Electric COS Class Monthly Impacts of Schedule 142 (7/15 through 6/16) – DR 30.35

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
Secondary Voltage - Small (Residential)												
Usage (kWh)	730	721	662	770	1,092	1,243	1,218	985	978	748	715	636
Billed revenue	$79	$78	$72	$85	$119	$137	$135	$110	$108	$83	$79	$72
Schedule 142 billed revenue	$3.45	$3.41	$3.13	$3.64	$5.17	$5.88	$5.76	$4.66	$4.62	$3.54	$4.56	$4.06
Percent of average monthly bill	4.4%	4.4%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	4.2%	5.7%	5.6%
Secondary Voltage - Small (Non-Residential)												
Usage (kWh)	2,095	1,965	1,767	1,836	2,057	2,283	2,385	1,893	2,135	1,706	1,874	1,750
Billed revenue	$223	$210	$191	$204	$225	$249	$259	$211	$234	$185	$200	$189
Schedule 142 billed revenue	$7.22	$6.77	$6.09	$6.33	$7.09	$7.87	$8.22	$6.52	$7.36	$5.88	$6.23	$5.82
Percent of average monthly bill	3.2%	3.2%	3.2%	3.1%	3.1%	3.2%	3.2%	3.1%	3.1%	3.2%	3.1%	3.1%
Secondary Voltage - Medium												
Usage (kWh)	33,442	32,121	29,345	30,192	31,329	34,790	33,142	29,987	33,414	26,698	28,680	30,813
Billed revenue	$3,256	$3,061	$2,869	$3,237	$3,360	$3,599	$3,499	$3,249	$3,468	$2,581	$2,786	$2,988
Schedule 142 billed revenue	$115	$111	$101	$104	$108	$120	$114	$103	$115	$92	$95	$103
Percent of average monthly bill	3.5%	3.6%	3.5%	3.2%	3.2%	3.3%	3.3%	3.2%	3.3%	3.6%	3.4%	3.4%
Secondary Voltage - Large												
Usage (kWh)	203,954	217,802	198,193	201,912	195,002	215,686	195,793	191,643	197,903	192,315	174,125	220,133
Billed revenue	$18,644	$18,409	$17,568	$19,924	$18,739	$20,223	$18,833	$19,410	$18,901	$16,045	$15,720	$19,102
Schedule 142 billed revenue	$471	$389	$418	$381	$353	$397	$361	$403	$358	$366	$565	$612
Percent of average monthly bill	2.5%	2.1%	2.4%	1.9%	1.9%	2.0%	1.9%	2.1%	1.9%	2.3%	3.6%	3.2%
Primary Voltage Class												
Usage (kWh)	210,825	179,955	178,790	183,182	183,242	201,847	185,521	194,884	186,357	162,826	152,594	195,087
Billed revenue	$18,441	$15,154	$15,836	$17,770	$17,129	$19,360	$17,292	$18,755	$17,542	$13,650	$13,581	$16,930
Schedule 142 billed revenue	$449	$342	$396	$385	$351	$446	$360	$405	$373	$328	$619	$677
Percent of average monthly bill	2.4%	2.3%	2.5%	2.2%	2.0%	2.3%	2.1%	2.2%	2.1%	2.4%	4.6%	4.0%
Campus Rate Class												
Usage (kWh)	537,423	433,793	415,719	405,390	371,785	431,818	434,171	339,369	348,014	348,529	447,169	382,037
Billed revenue	$45,985	$35,444	$34,589	$32,710	$30,204	$36,265	$35,367	$28,143	$27,772	$28,911	$35,369	$30,934
Schedule 142 billed revenue	$1,852	$1,495	$1,433	$1,397	$1,281	$1,488	$1,496	$1,169	$1,199	$1,201	$1,486	$1,270
Percent of average monthly bill	4.0%	4.2%	4.1%	4.3%	4.2%	4.1%	4.2%	4.2%	4.3%	4.2%	4.2%	4.1%
High Voltage Class												
Usage (kWh)	2,339,720	2,287,225	1,770,304	2,192,979	3,410,751	791,697	2,133,334	3,807,16	339,733	1,849,93	1,979,08	2,027,04
Billed revenue	$168,140	$166,897	$134,365	$160,645	$241,940	$63,860	$156,250	$266,636	$35,837	$137,971	$146,161	$147,849
Schedule 142 billed revenue	$8,063	$7,882	$6,100	$7,557	$11,753	$2,728	$7,351	$13,119	$1,171	$6,375	$6,578	$6,738
Percent of average monthly bill	4.8%	4.7%	4.5%	4.7%	4.9%	4.3%	4.7%	4.9%	3.3%	4.6%	4.5%	4.6%
All COS Classes Subject to Schedule 142 Deferral												
Usage (kWh)	1,490	1,437	1,314	1,433	1,767	1,920	1,904	1,652	1,617	1,339	1,338	1,319
Billed revenue	$150	$143	$133	$151	$185	$204	$202	$175	$172	$137	$137	$134
Schedule 142 billed revenue	$5.64	$5.35	$4.96	$5.45	$6.94	$7.64	$7.56	$6.48	$6.30	$5.12	$6.44	$6.04
Percent of average monthly bill	3.8%	3.7%	3.7%	3.6%	3.8%	3.8%	3.7%	3.7%	3.7%	3.7%	4.7%	4.5%

In order to visualize and contrast the impacts on customer electric revenues between COS classes, the percentage of monthly electric revenues attributed to Schedule 142 is shown in Figure III.3, which includes the entire 36 months of the first through third evaluation years.

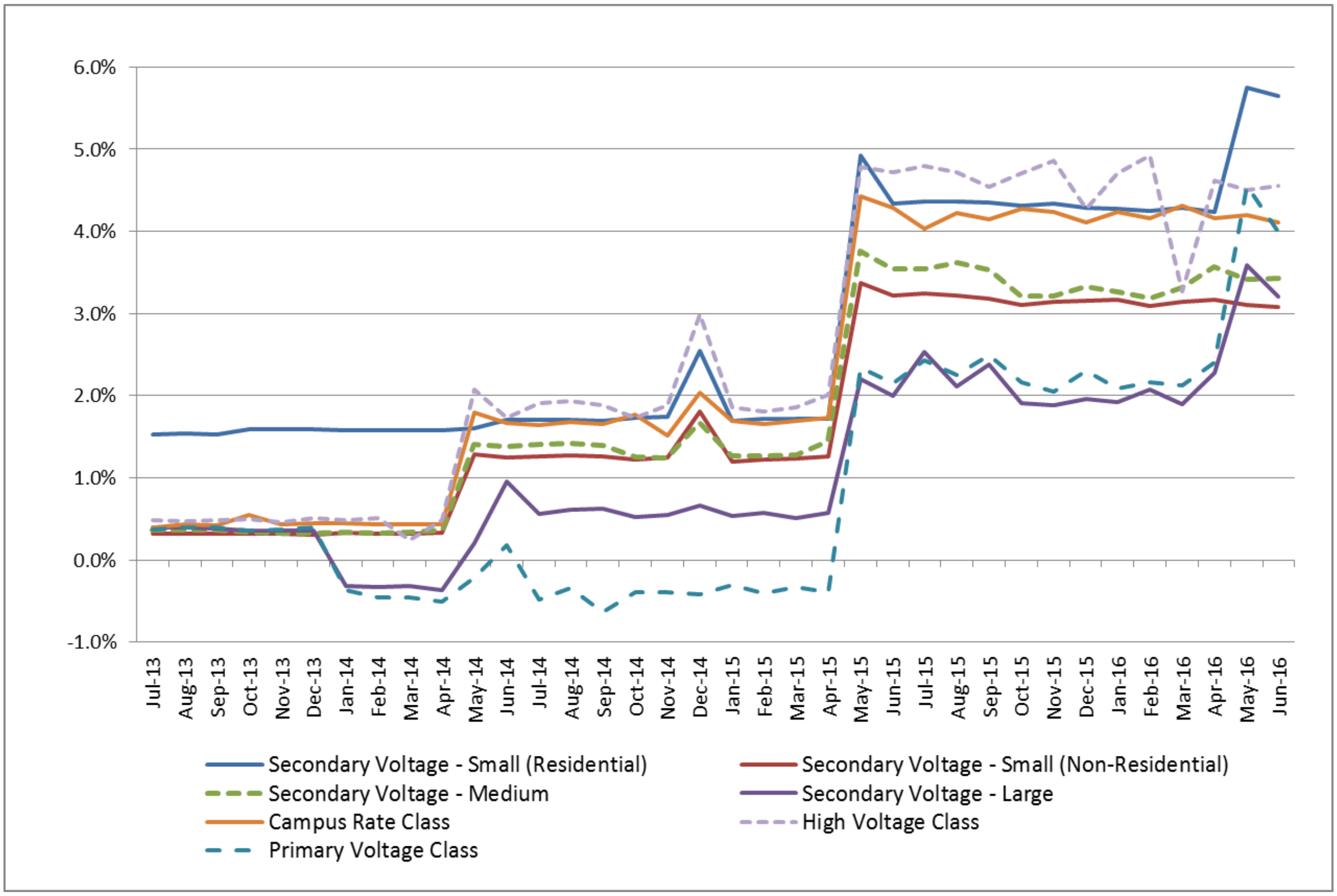


Figure III.3: Schedule 142 as a Percent of Monthly Class Revenues – DR 30.35

Figure III.3 shows a generally rising level of Schedule 142 revenue as a percentage of total revenue. Beginning with the third rate year (May 2015), Schedule 142 revenue as a percentage of total revenue is clustered around 3% for all COS classes. Schedule 142 revenue in the Residential, Campus Rate and High Voltage COS classes varies between 4% and 5% of total revenue through the third rate year (May 2015 through April 2016) while the Secondary Voltage-Large and Primary Voltage COS classes are below the third year average of about 3%. Small Non-Residential and Medium Secondary Voltage COS classes are near the 3% average throughout the third rate year.

The spike in all classes in December 2014 is due to a one-time rate credit for net proceeds from the sale of electric facilities in Jefferson County to Jefferson PUD. Proceeds received from Jefferson PUD from the sale were paid to PSE customers in the form of a credit to their

December 2014 bill, but had no impact on Schedule 142 revenue. This caused a drop in total revenue, with no change in actual Schedule 142 revenue, resulting in a one-time percentage increase of Schedule 142 revenue as a percentage of total revenue.[17]

The first few months of rate year four (May and June 2016) are also shown in Figure III.3. Three COS classes, Secondary Voltage Small - Residential, Secondary Voltage - Large and Primary Voltage increase a full percentage point while other COS classes remain near their May 2015 through April 2016 levels. The generally increasing pattern of Schedule 142 revenue as a percentage of total revenue deserves closer examination. An analysis of the influence of the K-factor, deferral balances and soft cap on the Schedule 142 rate is presented in Section VII of this report.

Natural Gas COS Classes

Like the electric tariff tracker adjustment, the decoupling rate impacts for natural gas are comprised of the combined impacts of the K-factor adjustment and the decoupling deferrals. Taken together, these two components make up the decoupling rate (Schedule 142 surcharge) that is applied to units of energy sold. Table III.7 shows the Schedule 142 surcharge, by Cost of Service class, that is subject to the decoupling deferral component; the corresponding impact on annual revenues from July 2013 through June 2016 is also shown in Table III.7.

Table III.7: Gas COS Class Revenue Impacts of Schedule 142 (7/13 through 6/16) – DR 30.35

NATURAL GAS (Three Years)							
				Schedule 142 Surcharge			
PSE Cost of Service Class	Rate Schedules	Number of Customers (Average Monthly)	Total Billed Revenue	Revenue	Percent of Total Revenue	Per Customer	Per Customer Per Year
Residential	23, 53, 16	732,314	$1,859,978,413	$37,421,827	2.0%	$51	$17
Commercial & Industrial Class	31, 31T, 61	55,434	$629,627,252	$10,408,261	1.7%	$188	$63
Large Volume Class	41, 41T	1,485	$171,222,835	$2,463,309	1.4%	$1,658	$553
Limited Interruptible Class	86, 86T	270	$21,723,527	$274,949	1.3%	$1,018	$339
Totals		789,503	$2,682,552,028	$50,568,346	1.9%	$64	$21

(c) Rate Schedule 16 is not subject to the decoupling deferral but is included in the Residential COS class and therefor in our analysis by COS class.

[17] See PSE's Response to H. GIL PEACH & ASSOCIATES Data Request No. 20.57.

Over $50 million was collected through the Schedule 142 surcharge from July 2013 through June 2016: 1.9% of total revenue. 74% of total Schedule 142 revenue came from the Residential COS class, with non-residential classes making up the remaining 26%. Schedule 142 revenues amounted to 2.0% of the total revenue from Residential natural gas (Schedules 23 & 53) customers, adding $51 of revenues per residential customer for the three years examined (or $17 per year).

Natural gas customers in the Commercial and Industrial COS class contributed over $10 million from Schedule 142 over the three years examined, second only to the Residential class. Per customer, Commercial and Industrial COS class customers paid $188 in Schedule 142 contributions for the three years ($63 average per year): 1.7% of their total PSE natural gas bill.

Schedule 142 revenues in the Large Volume COS class were 1.4% of total revenue for that class. The Limited Interruptible class paid the least amount of total natural gas revenue attributable to Schedule 142, and the lowest percent impact (1.3%) of class revenues.

Monthly Impacts of Decoupling Tariff Tracker Adjustments (Natural Gas)

Monthly usage and Schedule 142 surcharge impacts per customer over the first through third Evaluation Years are shown in Table III.8, Table III.9 and Table III.10, respectively. Monthly revenues from Schedule 142 tend to follow the pattern of volumetric sales. This pattern can be seen for residential natural gas (Schedules 23 & 53) customers in

Figure III.4.

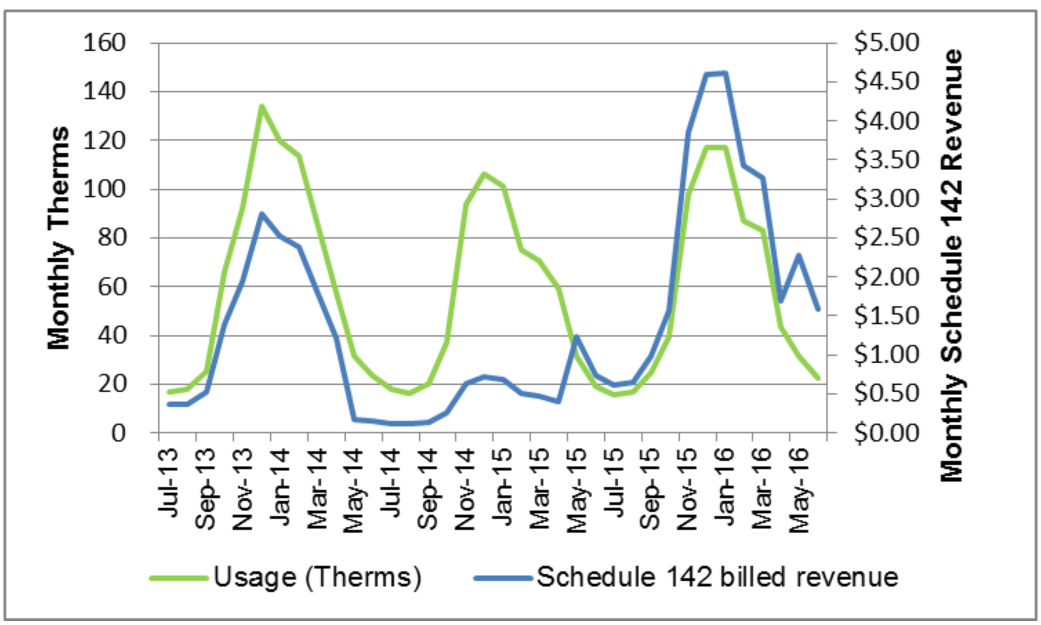


Figure III.4: Residential Gas COS Class (Schedules 23 & 53) Monthly Usage and Schedule 142 Bill – DR 30.35

Due to its characteristic seasonality and following the pattern of volumetric sales, the surcharge paid per customer varies significantly by month for the Residential Class, ranging from a low of $0.11 per customer in August of 2014 to a high of $4.60 per customer in December 2015 and January 2016. Although residential volumes and Schedule 142 revenues tend to move together, exceptions to this pattern can occur with changes to the Schedule 142 rate. For example, the Schedule 142 rate per therm for residential customers dropped from $0.02101 to $0.00677 effective May 1, 2014. This drop in Schedule 142 rate per therm was due to a negative balance in deferrals (over-collection of revenues) from calendar year 2013 and had the effect shown in Figure III.4 of lowering Schedule 142 revenues over the rate year May 2014 through April 2015.

The impacts of Schedule 142 rate changes, when expressed as a percentage of total revenue, are less volatile. The months of May and June can be exceptions and show significant differences in Schedule 142 revenue percentage from preceding months. This is due to the May 1 effective date of new Schedule 142 rate adjustments. For example, when the Schedule 142 rate applied to Residential dropped in May of 2014 (as described in the preceding paragraph), the percentage of the Schedule 142 surcharge on the average Residential bill dropped from 1.7% in April 2014 to 0.4 % in May of 2014 (Table III.8). Likewise, when the Schedule 142 rate applied to Residential customers increased in May of 2015, the percentage that Schedule 142 makes up of the average Residential bill increased from 0.5% in April 2015 to 2.7% in May 2015 (see Table III.9)

Table III.8: Gas COS Class Average Customer Monthly Impacts of Schedule 142 (7/13 - 6/14) – DR 30.35

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
Residential												
Usage (Therms)	17	18	25	66	92	134	120	114	87	58	32	24
Billed revenue	$29	$29	$37	$78	$106	$150	$136	$129	$101	$71	$44	$35
Schedule 142 billed revenue	$0.36	$0.37	$0.53	$1.39	$1.94	$2.82	$2.52	$2.39	$1.82	$1.21	$0.17	$0.16
Percent of average monthly bill	1.3%	1.3%	1.5%	1.8%	1.8%	1.9%	1.9%	1.8%	1.8%	1.7%	0.4%	0.5%
Commercial & Industrial Class												
Usage (Therms)	140	132	150	288	408	600	502	571	410	291	233	116
Billed revenue	$170	$160	$176	$305	$420	$604	$514	$577	$430	$314	$266	$154
Schedule 142 billed revenue	($0.55)	($0.52)	($0.59)	($1.13)	($1.61)	($2.36)	($1.98)	($2.25)	($1.62)	($1.15)	$5.26	$2.70
Percent of average monthly bill	-0.3%	-0.3%	-0.3%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	2.0%	1.8%
Large Volume Class												
Usage (Therms)	3,088	1,543	4,500	4,467	5,359	7,287	6,162	6,944	5,452	4,930	3,694	3,552
Billed revenue	$2,470	$668	$4,062	$3,167	$3,737	$4,947	$4,312	$4,638	$3,834	$3,479	$2,770	$2,825
Schedule 142 billed revenue	($7)	($3)	($10)	($8)	($10)	($13)	($11)	($12)	($10)	($9)	$30	$52
Percent of average monthly bill	-0.3%	-0.4%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	1.1%	1.8%
Limited Interruptible Class												
Usage (Therms)	1,121	870	992	2,996	3,269	6,336	4,986	4,826	4,346	3,353	1,928	1,447
Billed revenue	$1,102	$849	$1,005	$2,322	$2,573	$4,691	$3,789	$3,639	$3,315	$2,645	$1,551	$1,274
Schedule 142 billed revenue	($3)	($2)	($3)	($7)	($7)	($13)	($10)	($10)	($9)	($7)	$21	$21
Percent of average monthly bill	-0.2%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	1.4%	1.6%
All COS Classes Subject to Schedule 142 Deferral												
Usage (Therms)	32	29	43	92	126	183	161	161	121	85	54	37
Billed revenue	$44	$40	$55	$101	$136	$193	$172	$171	$133	$96	$66	$50
Schedule 142 billed revenue	$0.28	$0.30	$0.43	$1.19	$1.66	$2.41	$2.17	$2.03	$1.55	$1.02	$0.59	$0.45
Percent of average monthly bill	0.6%	0.8%	0.8%	1.2%	1.2%	1.3%	1.3%	1.2%	1.2%	1.1%	0.9%	0.9%

Table III.9: Gas COS Class Average Customer Monthly Impacts of Schedule 142 (7/14 - 6/15) – DR 30.35

	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
Residential												
Usage (Therms)	18	16	20	37	94	106	101	75	70	59	31	19
Billed revenue	$29	$28	$32	$49	$108	$123	$118	$91	$86	$73	$46	$32
Schedule 142 billed revenue	$0.12	$0.11	$0.14	$0.25	$0.64	$0.72	$0.69	$0.51	$0.48	$0.40	$1.24	$0.75
Percent of average monthly bill	0.4%	0.4%	0.4%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	2.7%	2.3%
Commercial & Industrial Class												
Usage (Therms)	134	132	138	193	431	477	463	357	340	289	200	139
Billed revenue	$169	$166	$172	$225	$464	$519	$509	$402	$383	$329	$242	$180
Schedule 142 billed revenue	$3.10	$3.06	$3.19	$4.48	$10.00	$11.07	$10.75	$8.30	$7.88	$6.70	$6.06	$4.21
Percent of average monthly bill	1.8%	1.8%	1.9%	2.0%	2.2%	2.1%	2.1%	2.1%	2.1%	2.0%	2.5%	2.3%
Large Volume Class												
Usage (Therms)	3,012	3,144	3,008	3,674	6,098	4,962	5,573	4,330	5,567	5,000	4,169	3,351
Billed revenue	$2,381	$2,511	$2,365	$2,803	$4,364	$3,752	$4,148	$3,278	$4,190	$3,772	$3,176	$2,640
Schedule 142 billed revenue	$46	$49	$45	$51	$72	$63	$69	$56	$70	$65	$71	$63
Percent of average monthly bill	1.9%	1.9%	1.9%	1.8%	1.6%	1.7%	1.7%	1.7%	1.7%	1.7%	2.2%	2.4%
Limited Interruptible Class												
Usage (Therms)	1,005	855	1,043	2,059	3,875	4,258	4,262	4,192	3,574	3,911	1,645	1,308
Billed revenue	$952	$830	$1,045	$1,722	$3,121	$3,533	$3,519	$3,405	$2,973	$3,200	$1,499	$1,225
Schedule 142 billed revenue	$16	$13	$16	$29	$50	$55	$54	$53	$46	$50	$30	$25
Percent of average monthly bill	1.6%	1.6%	1.6%	1.7%	1.6%	1.6%	1.5%	1.6%	1.6%	1.6%	2.0%	2.0%
All COS Classes Subject to Schedule 142 Deferral												
Usage (Therms)	32	31	35	56	130	143	139	104	101	86	51	34
Billed revenue	$44	$43	$46	$67	$143	$159	$155	$120	$115	$99	$66	$47
Schedule 142 billed revenue	$0.42	$0.42	$0.44	$0.66	$1.45	$1.58	$1.54	$1.18	$1.14	$0.98	$1.71	$1.11
Percent of average monthly bill	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	2.6%	2.3%

Table III.10: Gas COS Class Average Customer Monthly Impacts of Schedule 142 (7/15 - 6/16) - DR 30.35

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
Residential												
Usage (Therms)	16	17	25	40	98	117	117	87	83	43	31	22
Billed revenue	$28	$29	$38	$54	$99	$116	$117	$90	$86	$51	$40	$32
Schedule 142 billed revenue	$0.61	$0.65	$0.98	$1.56	$3.85	$4.60	$4.60	$3.42	$3.27	$1.70	$2.27	$1.59
Percent of average monthly bill	2.2%	2.2%	2.6%	2.9%	3.9%	4.0%	3.9%	3.8%	3.8%	3.4%	5.6%	4.9%
Commercial & Industrial Class												
Usage (Therms)	127	132	156	216	418	601	488	393	415	245	171	173
Billed revenue	$167	$171	$195	$256	$385	$532	$443	$366	$380	$242	$184	$185
Schedule 142 billed revenue	$3.84	$4.00	$4.73	$6.56	$12.68	$18.23	$14.81	$11.93	$12.60	$7.42	$8.45	$8.40
Percent of average monthly bill	2.3%	2.3%	2.4%	2.6%	3.3%	3.4%	3.3%	3.3%	3.3%	3.1%	4.6%	4.5%
Large Volume Class												
Usage (Therms)	2,964	3,142	3,272	4,008	5,373	7,257	6,555	5,116	6,297	4,242	3,922	3,434
Billed revenue	$2,391	$2,462	$2,560	$3,010	$3,428	$3,940	$3,685	$2,938	$3,451	$2,511	$2,422	$2,102
Schedule 142 billed revenue	$58	$58	$59	$67	$86	$101	$99	$87	$89	$71	$105	$94
Percent of average monthly bill	2.4%	2.4%	2.3%	2.2%	2.5%	2.6%	2.7%	3.0%	2.6%	2.8%	4.3%	4.5%
Limited Interruptible Class												
Usage (Therms)	942	1,555	776	1,990	3,907	6,386	4,509	4,948	5,259	2,562	1,822	1,439
Billed revenue	$955	$1,360	$938	$1,753	$2,557	$3,849	$2,823	$3,084	$3,172	$1,703	$1,298	$1,091
Schedule 142 billed revenue	$19	$28	$18	$37	$66	$102	$75	$81	$85	$45	$54	$43
Percent of average monthly bill	2.0%	2.0%	1.9%	2.1%	2.6%	2.7%	2.7%	2.6%	2.7%	2.6%	4.1%	3.9%
All COS Classes Subject to Schedule 142 Deferral												
Usage (Therms)	29	31	40	60	131	166	156	119	119	66	49	39
Billed revenue	$42	$44	$54	$74	$126	$153	$147	$115	$113	$69	$55	$47
Schedule 142 billed revenue	$0.95	$1.00	$1.35	$2.04	$4.63	$5.76	$5.51	$4.19	$4.10	$2.24	$2.90	$2.25
Percent of average monthly bill	2.2%	2.3%	2.5%	2.8%	3.7%	3.8%	3.8%	3.6%	3.6%	3.3%	5.3%	4.8%

Expressing Schedule 142 impacts as a percentage of total revenue allows for a comparison between COS classes. In order to contrast the impacts on customer bills among natural gas rate classes, the percentage of Schedule 142 adjustments in relation to the total monthly bill are shown in Figure III.5.

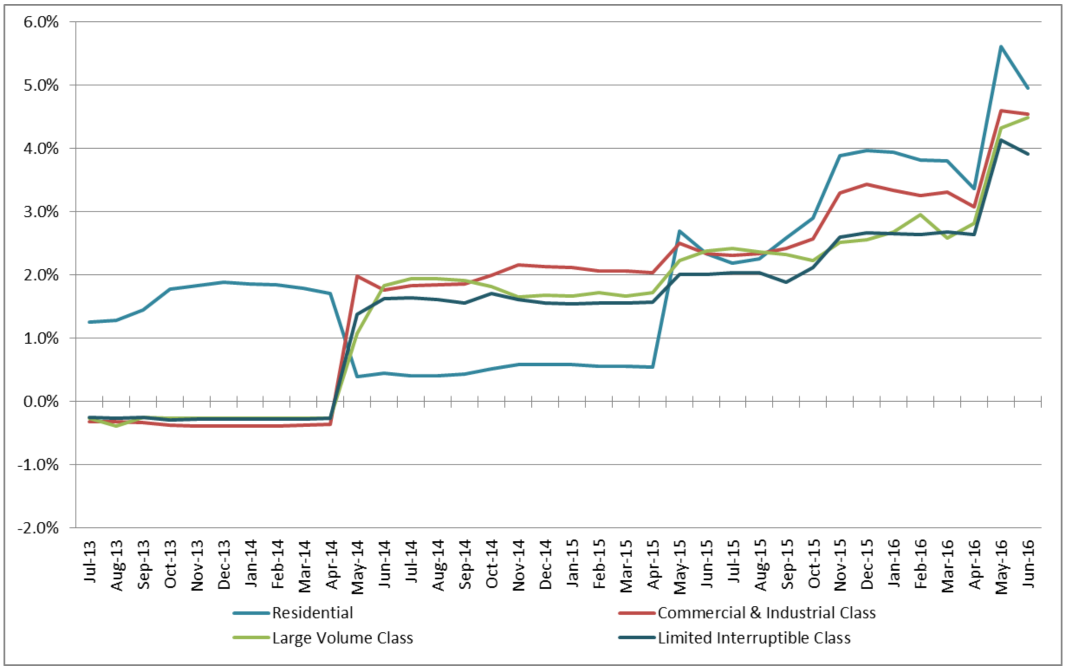


Figure III.5: Schedule 142 as Percent of Monthly Natural Gas Revenues by Class – DR 30.35

Figure III.5 shows a generally increasing level of Schedule 142 revenue as a percentage of total billed revenue. Figure III.5 also shows a large drop in Residential in May of 2014 that lasts through April of 2015. As discussed earlier in this section, this drop was due to a sharp drop in the Schedule 142 rate applied to Residential due to a negative balance in deferrals (over-collection of revenues) from calendar year 2013.

Beginning with the third rate year (May 2015), Schedule 142 revenue as a percentage of total revenue is clustered around 2% for all COS classes. By November of 2015, all COS rate classes have jumped higher when compared with the start of the rate year (May 2015). This increase is due to a drop in the Purchased Gas Adjustment (PGA) rates, effective November 1, 2015, which caused an estimated 17.4% drop in total revenues across all gas rate classes.[18] When total revenue drops due to reasons unrelated to the decoupling rate adjustment, the Schedule 142 percentage of total revenue increases, and vice versa.

[18] Source: Nov 2015 PGA Rate Worksheets (C).xlxs, Combined Revenue Impact PGA-7

Size of Effects

In this part of the study, we developed impacts of the decoupling tariff tracker adjustments in relation to sales, as a percent of monthly bills and in total dollars for each rate category customarily used for purposes of PSE's cost of service analyses.

Since the effect of decoupling (initially the K-factor, then the yearly deferral adjustments) is applied as a volumetric rate adjustment, its impact follows volumetric sales for each COS class. Within each COS class, if sales are less than planned for a particular year, the decoupling deferral adjustment results in a bill per unit of energy increase for the following year. If sales are higher than planned for a particular year, the decoupling deferral adjustment causes a volumetric billing decrease for the following year. The effect of Schedule 142 on revenue overall is very small for both electricity (2.2% -- see last row of Table III.3) and natural gas (1.9% - see last row of Table III.7). We provide a visual sense of the very small *overall* decoupling impacts in pie charts (Figure III.6 and Figure III.7).

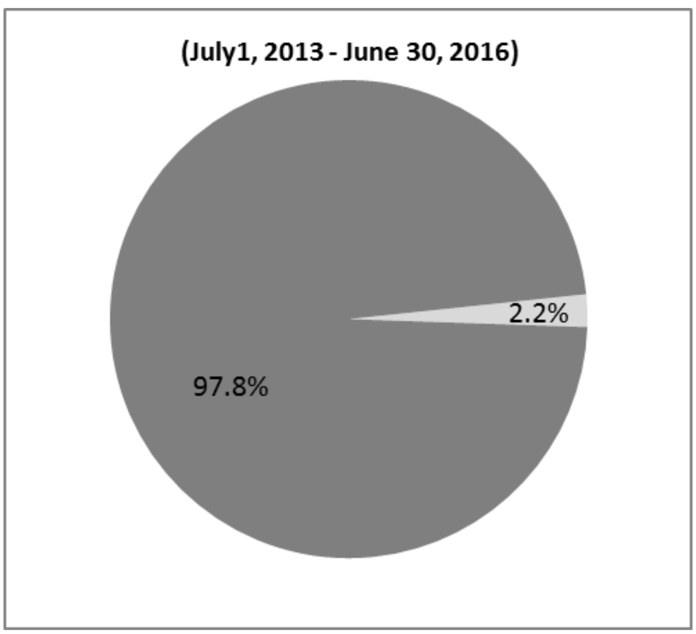


Figure III.6: Electricity - Schedule 142 Surcharge as a Percent of Revenue for Surcharge Classes – DR 30.35

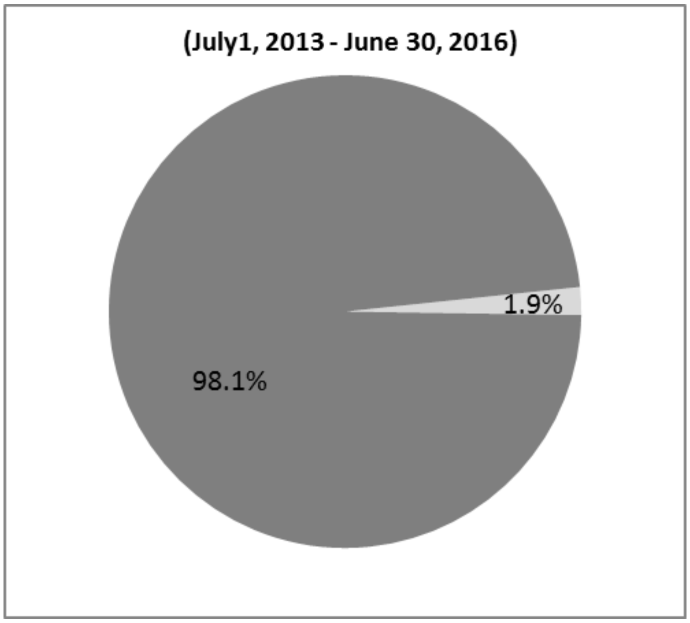


Figure III.7: Natural Gas - Schedule 142 Surcharge as Percent of Revenue for Surcharge Classes – DR 3.35

Given that the overall decoupling impact is very small, what is the impact by COS class? For electricity, the maximum three-year impact among the COS classes was (2.8%) for the residential class (Table III.3, Row 1). For natural gas, the maximum three-year impact among the COS classes was 2.0% for the residential class (Table III.7, Row 1).

As the three-year evaluation period neared its ending, the largest increase in the Schedule 142 surcharge occurred in May of 2016, for electricity. The electric residential class experienced a Schedule 142 surcharge adjustment of 5.7%. In the same month, the Primary Voltage rate class (4.6%) and the Large Secondary Voltage class (3.6%) also experienced a jump of one to two percentage points in Schedule 142 revenue as a percent of total revenue.

For natural gas, increases in the Schedule 142 surcharges have, at times, been smaller than for electric customers but they are generally similar, especially with the Schedule 142 rate change effective May 1, 2016. Every gas rate class subject to the deferral adjustment experienced a jump in Schedule 142 rates effective May 1, 2016 to the extent that Schedule 142 revenue from decoupled COS classes increased to 5.3% of revenue in May of 2016. In percentage terms, the Gas Residential class experienced the largest Schedule 142 surcharge adjustment of 5.6% in May 2016. The smallest increase was in the Limited Interruptible class, which experienced a 4.1% increase in the same month.

Section Summary

Based on our analysis of three years of data, we conclude that the overall impacts of Schedule 142 on average customer bills are very small for both electricity and natural gas but tend to be increasing for both electricity and natural gas. The impacts and trends include both the decoupling adjustment and the K-factor adjustment. For electricity and natural gas, the impacts by COS class are also generally small over the three years examined but have been trending higher. The overall trend in Schedule 142 revenue as a percentage of total revenue for both electricity and natural gas is shown in Figure III.8, below.[19]

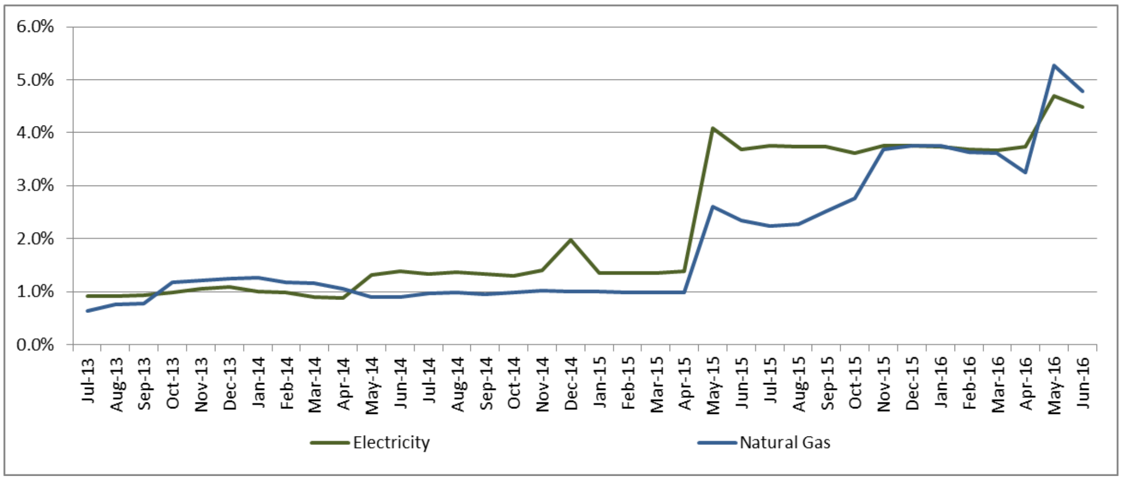


Figure III.8: Electricity and Natural Gas Schedule 142 Revenues as Percent of Total Revenue – DR 30.35

The upward trend in Schedule 142 impact on revenue, and therefore customer bills, is evident in Figure III.8. It is also clear from the monthly analysis summarized in Figure III.3 and Figure III.5 that, while there have been differences in the level of impact between COS classes, those differences tend to shift over time with all classes showing the same overall upward trend. In order to understand the change in Schedule 142 percentages of total bills, it is necessary to examine several factors embedded in the decoupling mechanism, including the impact of trending use per customer, K-factor, deferral adjustments, deferral account balances and the soft cap on rates. This report reviews the impact of these factors in Section VII. It is also worth noting that non-decoupling factors such as the Purchased Gas Adjustment discussed earlier can also have an impact on Schedule 142 as a percentage of total revenues.

[19] Figure III.8 only includes COS classes subject to Schedule 142 decoupling deferrals.

IV. Impact on Low-Income Customers

This section analyzes and evaluates the impact of decoupling on low-income customers and is comprised of four parts (Figure IV.1). Results follow, with “a” (effects on low-income customers) and “d” (contrast of effects on low-income customers vs. average residential customers) combined. This is followed by a comparison of low-income conservation savings, expenditures and customers served compared with regular residential programs. The section concludes with a description of the modifications to low-income programs since decoupling.

Note: In this section of the study, the time period examined is from July 2010 through June 2016.

Task Element 3: Evaluate the Impact on Low-Income Customers

This section analyzes and evaluates the impact of the decoupling mechanisms, specifically on PSE’s low-income customers (where low-income is defined as a customer receiving bill assistance through the HELP or LIHEAP program within the same calendar year of the evaluation time period) including:

a. A summary of the annual deferrals and rate impacts of the decoupling tariff tracker adjustments (cents per kWh, cents per therm, total dollars and percent of monthly bills) on the group of customers receiving bill assistance through PSE’s low-income programs;

b. A summary of annual low-income conservation program savings, expenditures and customers served compared with the rest of the residential class, where low-income conservation programs are defined as programs currently being run under electric and gas Schedule 201 (Prior to 2013, the gas schedule was numbered as Schedule 203);

c. A description of any modifications to conservation programs targeted to low-income customers since the inception of the decoupling mechanisms; modifications include changes to funding levels as well as changes to specific measures or programs;

d. A comparison of the effect of the decoupling tariff tracker adjustment on the average customer receiving bill assistance through PSE’s low-income programs relative to the impact on PSE’s average residential customer.

Figure IV.1: Impact on Low-Income Customers

The definition of low-income, as used in this study, are customers identified as Bill Assisted customers in the year under review. This should be understood as one of many flawed indicators of household income insufficiency (or low-income). The advantage of using this indicator is that (a) it is referenced to the official US poverty accounting at the level of 150% of the federally defined poverty level (FPL) and (b) it is already operationalized within utility records.[20] Of course (a) there are many other customers within 150% of poverty who are not receiving bill assistance and (b) an analysis of households with insufficient income would be more truthful if set at or above 250% to 350% of the federal poverty. However, as the chosen indicator, it will serve for the purposes of this analysis, which is focused on customers assisted by the utility vs. those who are not.

Decoupling Effect on Low-Income Electric Customers

The decoupling effect on low-income residential electric consumers is evaluated in terms of the impact on their monthly bills caused by changes in the Schedule 142 rate, which, as shown in Table IV.2 and Table IV.3 in Section 3 of this study, is a very small percentage of the overall residential rate. PSE does not offer a low-income rate;[21] low-income residential customers are billed according to the same rate-schedule as regular residential customers, but may receive energy bill assistance grants through PSE.

The Schedule 142 residential decoupling rate is comprised of the combined impacts of the K-factor adjustment and the true-up of decoupling deferrals. Taken together, these two components make up the Schedule 142 decoupling rate. The Schedule 142 rate is volumetric, meaning the bill impact is determined by how much energy each customer uses. The decoupling impact on low-income bills is measured by changes in monthly billings that are attributed the Schedule 142 decoupling rate applicable to all residential customers. The Schedule 142 residential electric rate was changed several times during the three-year evaluation. The rate for electricity was initially set at $.001628 per kWh on July 1, 2013. The Schedule 142 electric rate increased to $.001685 per kWh on May 1, 2014. It was increased again to $.004729 on May 1, 2015 and again to $.006383 in May 2016 (Table IV.1).

[20] PSE HELP eligibility is at 150% of the Federal Poverty Level. Nationally, eligibility for federal Low Income Home Energy Assistance Program (LIHEAP) is at 150% of the Federal Poverty Level or 60% of State Median Income. In the State of Washington, however, eligibility is limited to 125% of the Federal Poverty Level. For Washington LIHEAP, see: http://www.commerce.wa.gov/wp-content/uploads/2016/10/ceo-liheap-eligibility-2016.pdf.

[21] In addition, there were no structural modifications to low-income bill assistance programs during the three-year study.

Table IV.1: Schedule 142 Electric Residential Rates – DR 30.11

Schedule 142 Electric Residential Rates		
Rate per kWh	Rate Change	Effective Date
$ 0.001628		1-Jul-13
$ 0.001685	$ 0.000057	1-May-14
$ 0.004729	$ 0.003044	1-May-15
$ 0.006382	$ 0.001653	1-May-16

The average bill impact is determined by comparing the typical residential electric bill without the Schedule 142 charge to the typical electric bill with the Schedule 142 charge. The data used in this analysis was provided in response to DR 30.11_Att A 121697-UE 121705-UG PSE Resp GIL PEACH DR 30.11_Attach A (1).

Table IV.2 and Table IV.3 summarize respectively the monthly and annual bill impacts of Schedule 142 rate on residential customers for the three evaluation years. For these tables, Year 1 is July 2013-June 2014; Year 2 is July 2014-June 2015 and Year 3 is July 2015-June 2016. For Bill Assisted customers, the decoupling Schedule 142 rate resulted in an average monthly bill impact of $1.75 during the first year, $2.02 during the second year, and $4.83 during the third year. For Non-Bill Assisted customers, the decoupling Schedule 142 rate resulted in an average monthly bill impact of $1.50 during the first year, $1.81 during the second year, and $4.31 during the third year.

Table IV.2: Residential Electric Bill Impact (Monthly) – DR 30.11

Three Year Residential Monthly Bill Impact				
	Year 1	Year 2	Year 3	Average
Bill Assisted				
Usage (kWh)	1,070	956	977	1,001
Total bill	$ 107.87	$ 88.37	$ 100.45	$ 98.89
Bill excluding Schedule 142	$ 106.12	$ 86.35	$ 95.62	$ 96.03
Schedule 142 bill impact	$ 1.75	$ 2.02	$ 4.83	$ 2.86
Schedule 142 bill impact percent	1.65%	2.34%	5.05%	3.01%
Non-Bill Assisted				
Usage (kWh)	918	865	872	885
Total bill	$ 92.08	$ 79.66	$ 89.24	$ 86.99
Bill excluding Schedule 142	$ 90.58	$ 77.85	$ 84.93	$ 84.45
Schedule 142 bill impact	$ 1.50	$ 1.81	$ 4.31	$ 2.54
Schedule 142 bill impact percent	1.66%	2.33%	5.07%	3.02%

As illustrated in Table IV.3, the annual average Schedule 142 bill impact for the Bill Assisted electric customer was $21.00 during the first year, $24.20 during the second year and $57.91 during the third year of the decoupling evaluation period. The annual average impact for the Non-Bill Assisted customer was $18.02 during the first year, $21.74 during the second year and $51.68 during year three of the decoupling evaluation period.

Table IV.3: Residential Electric Bill Impact (Annual) – DR 30.11

Three Year Residential Annual Bill Impact				
	Year 1	Year 2	Year 3	Average
Bill Assisted				
Usage (kWh)	12,840	11,470	11,724	12,011
Total bill	$ 1,294.39	$ 1,060.42	$ 1,205.37	$ 1,186.72
Bill excluding Schedule 142	$ 1,273.39	$ 1,036.22	$ 1,147.47	$ 1,152.36
Schedule 142 bill impact	$ 21.00	$ 24.20	$ 57.91	$ 34.37
Schedule 142 bill impact percent	1.65%	2.34%	5.05%	3.01%
Non-Bill Assisted			9.03%	
Usage (kWh)	11,020	10,381	10,458	10,620
Total bill	$ 1,105.01	$ 955.91	$ 1,070.88	$ 1,043.94
Bill excluding Schedule 142	$ 1,087.00	$ 934.17	$ 1,019.20	$ 1,013.46
Schedule 142 bill impact	$ 18.02	$ 21.74	$ 51.68	$ 30.48
Schedule 142 bill impact percent	1.66%	2.33%	5.07%	3.02%

The bill impact percentage is measured by the Schedule 142 bill impact as a percent of the monthly bill, excluding Schedule 142 rate. For Bill Assisted customers, the Schedule 142 bill impact percent was 1.65% in the first year, 2.34% for the second year, and 5.05% for the third year. For Non-Bill Assisted customers, the Schedule 142 percentage impacts are 1.66%, 2.33% and 5.07% for years 1, 2, and 3, respectively. Annual and monthly percentage impacts are equivalent. The Schedule 142 percentage impacts increased each year for both Bill Assisted and Non-Bill Assisted customers. This is expected due to the Schedule 142 rate increase that occurred each year during the evaluation period.

Viewing the cumulative Schedule 142 rate impact, the percentage impact on electric Bill Assisted residential customers average bills was a 9.03% over three years; the three-year cumulative impact on Non-Bill Assisted customers was. 9.06%. Annual and monthly percentage impacts are equivalent.

Table IV.4 presents a comparison of the relative bill impacts of the Schedule 142 rates on Bill Assisted and Non-Bill Assisted residential electric customers. During the three-year evaluation period, Bill Assisted customers experienced a very slightly larger average monthly bills ($0.25 in year 1, $0.20 in year 2 and $0.52 per monthly billing in year 3. Bill Assisted electric customers similarly experienced slightly larger average annual bill impacts than Non-Bill Assisted electric customers ($2.98 in year 1, $2.46 in year 2 and $6.22 per monthly billing in year 3). For this table, Year 1 is July 2013-June 2014; year 2 is July 2014-June 2015 and year 3 is July 2015-June 2016

Table IV.4: Bill Assisted and Non-Bill Assisted Electric Impact Comparisons – DR 30.11

Three Year Average Schedule 142 Electric Bill Impacts				
Average Monthly Impact				
	Non-Bill Assisted	Bill Assisted	Difference	% Difference
Year 1	$ 1.50	$ 1.75	$ 0.25	16.67%
Year 2	$ 1.81	$ 2.02	$ 0.21	11.60%
Year 3	$ 4.31	$ 4.83	$ 0.52	12.06%
Average	$ 2.54	$ 2.87	$ 0.33	13.44%
Average Annual Impact				
	Non-Bill Assisted	Bill Assisted	Difference	% Difference
Year 1	$ 18.02	$ 21.00	$ 2.98	16.54%
Year 2	$ 21.74	$ 24.20	$ 2.46	11.32%
Year 3	$ 51.68	$ 57.91	$ 6.23	12.05%
Average	$ 30.48	$ 34.37	$ 3.89	13.30%

The dollar differences in bill impact between Bill Assisted and Non-Bill Assisted residential electric customers is only a slight amount, though it increases over the three years. The percentage difference is more noticeable.

We attribute the difference in Bill Assisted and Non-Bill Assisted customer impacts to differences in usage levels. Because Schedule 142 is a volumetric charge, the impact increases in direct proportion to customer usage. Table IV.5 illustrates monthly usage patterns and differences between Bill Assisted and Non-Bill Assisted residential customers. The difference is calculated as Bill Assisted usage less Non-Bill Assisted usage, with a positive number indicating that Bill Assisted usage exceeds Non-Bill Assisted usage for the month or year. Bill Assisted customer usage exceeded Non-Bill Assisted customer usage by 14.18% in year one, 9.50% in year two, and 10.79% in year three.

Table IV.5: Bill Assisted and Non-Bill Assisted Electric Usage Trends – DR 30.11

Three Year Residential Electric Usage Trends													
Year One Usage (kWh)													
	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Annual
Bill-Assisted	745	732	710	840	1,091	1,498	1,537	1,503	1,355	1,155	901	773	12,840
Non-Bill Assisted	698	713	710	909	1069	1375	1215	1129	1013	824	710	656	11,020
Difference	47	19	1	-68	22	123	323	374	342	331	191	117	1,821
% Difference	6.27%	2.62%	0.09%	-8.11%	2.03%	8.20%	21.00%	24.89%	25.24%	28.65%	21.16%	15.14%	14.18%
Year One Usage (kWh)													
	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Annual
Bill-Assisted	704	697	707	701	931	1,356	1,394	1,253	1,142	984	861	739	11,470
Non-Bill Assisted	727	722	666	771	1088	1198	1139	893	933	849	702	694	10,381
Difference	-22	-24	41	-70	-157	158	255	360	209	135	159	45	1,090
% Difference	-3.15%	-3.49%	5.79%	-9.95%	-16.86%	11.67%	18.30%	28.70%	18.30%	13.76%	18.51%	6.10%	9.50%
YearThree Usage (kWh)													
	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Annual
Bill-Assisted	697	690	679	760	963	1,392	1,529	1,334	1,183	1,006	761	730	11,724
Non-Bill Assisted	732	722	661	770	1097	1238	1207	973	971	739	714	633	10,458
Difference	-35	-32	17	-10	-133	154	321	360	212	267	47	97	1,266
% Difference	-5.01%	-4.60%	2.53%	-1.35%	-13.84%	11.04%	21.02%	27.02%	17.94%	26.51%	6.21%	13.31%	10.79%

Figure IV.2 illustrates seasonal usage patterns for Bill Assisted and Non-Bill Assisted residential customers during the three-year evaluation period. Bill Assisted customers show a pattern of higher energy use (kWh) from December through May, suggesting higher electric space-heat costs.

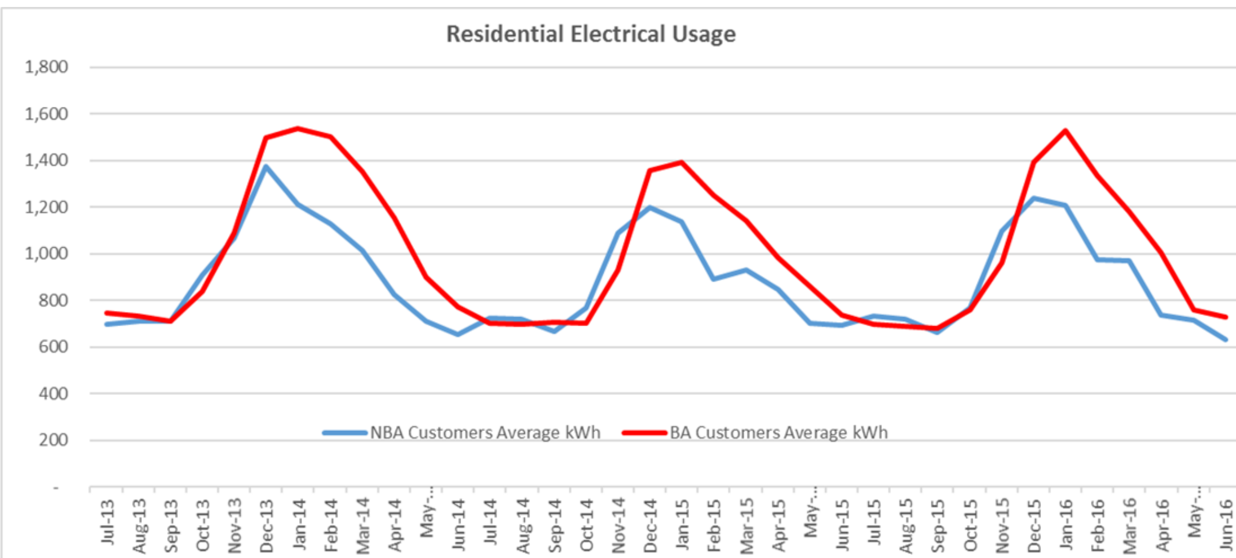
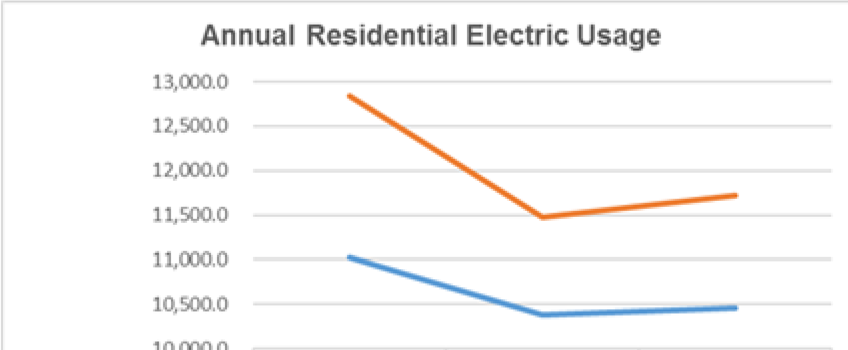


Figure IV.2: Monthly Bill Assisted and Non-Bill Assisted Residential Electric Usage (kWh) – DR 30.11

Figure IV.3 presents an overview of the three-year trends. Bill Assisted customers experienced higher usage rates during each of the three years that decoupling has been in place at PSE. From Year 1 to Year 2, both Assisted and Non-Bill Assisted customers experienced a decrease in usage of 10.67% and 5.80%, respectively. In Year 3, both groups experienced an increase in usage, with Bill Assisted customers increasing at 2.21% and Non-Bill Assisted customers increasing at a lower rate of 0.75%.



	Year 1	Year 2	Year 3
Non-Bill Assisted	11,019.6	10,380.6	10,458.4
Bill Assisted	12,840.3	11,470.2	11,723.9

Figure IV.3: Figure Graph of Annual Residential Electrical Usage (kWh) – DR 30.11

The overall conclusion is that energy usage by Bill Assisted and Non-Bill Assisted electric customers is essentially similar. However, since electric Bill Assisted customers tend to use slightly more energy,[22] the mechanism has a small potential over a span of several years to shift costs to low-income customers in the same pattern that would be experienced by any grouping of higher-use customers under cost-of-service rates. This is especially true if, on average, the rate of conservation is lower for low-income customers.[23] Continued and intensified efforts to improve energy efficiency in low-income homes can help mitigate this potential impact.

[22] The energy comparison here is not carried down to the next level of analysis, which could standardize for household size and housing type. This means that the analysis at the top level may mask an underlying "mixture" problem.

[23] Cost shifting could occur in the future if average usage decreases for regular residential customers at a faster rate than it decreases for low-income (Bill Assisted) customers. It might take several cycles for a pattern of this type to become pronounced.

Decoupling Effect on Low-Income Natural Gas Customers

The decoupling impact on low-income residential natural-gas customers is measured by changes in monthly billings that are attributed to the Schedule 142 decoupling rate applicable to all residential natural-gas customers. The natural gas Schedule 142 impact analysis mirrors the method used to evaluate residential electric customer impacts.

The Schedule 142 natural-gas rate was changed several times during the three-year evaluation period, which extended from July 1, 2013 to June 30, 2016. Table IV.6 indicates that the rate for natural gas was initially set at $0.0210100 per Therm on July 1, 2013. The rate decreased to $.0067700 per Therm on May 1, 2014. It was then increased to $.039300 on May 1, 2015 and again to $.071570 on May 2016.

Table IV.6: Schedule 142 Natural Gas Residential Rates (Schedules 23 & 53) – DR 30.11.

Schedule 142 Natural Gas Residential Rates		
Rate per Therm	Rate Change	Effective Date
$ 0.021010		01-Jul-13
$ 0.006770	$ (0.01424)	01-May-14
$ 0.039300	$ 0.03253	01-May-15
$ 0.071570	$ 0.03227	01-May-16

Table IV.7 and Table IV.8 summarize respectively monthly and annually the bill impacts of Schedule 142 on residential natural gas (Schedules 23 & 53) customers for the three evaluation years. Year 1 is Jul 2013-Jun 2014, year 2 is Jul 2014-Jun 2015 and year 3 is Jul 2015-Jun 2016. The decoupling Schedule 142 rate resulted in an average monthly bill impact for Bill Assisted customers of $1.19 during the first year, $0.52 during the second year, and $2.26 during the third year. For Non-Bill Assisted customers, the decoupling Schedule 142 rate resulted in an average monthly bill impact of $1.31 during the first year, $0.50 during the second year, and $2.43 during the third year.

Table IV.7: Residential Natural Gas (Sch. 23 & 53) Bill Impact (Monthly) – DR 30.11

Three Year Residential Monthly Bill Impact				
	Year 1	Year 2	Year 3	Average
Bill Assisted				
Usage (Therms)	61	50	53	55
Total bill	$ 70.02	$ 60.04	$ 65.30	$ 65.12
Bill excluding Schedule 142	$ 68.83	$ 59.53	$ 63.04	$ 63.80
Schedule 142 bill Impact	$ 1.19	$ 0.52	$ 2.26	$ 1.32
Schedule 142 bill impact (percent)	1.73%	0.87%	3.58%	2.06%
Non-Bill Assisted				
Usage (Therms)	66	54	58	59
Total bill	$ 74.96	$ 63.79	$ 70.24	$ 69.66
Bill excluding Schedule 142	$ 73.64	$ 63.28	$ 67.82	$ 68.25
Schedule 142 bill Impact	$ 1.31	$ 0.50	$ 2.43	$ 1.41
Schedule 142 bill impact (percent)	1.78%	0.79%	3.58%	2.05%

As illustrated in Table IV.8, the annual average Schedule 142 impact for natural gas Bill Assisted customers was $14.29 during the first year, $6.22 during the second year and $27.09 during year three of the decoupling evaluation period. The average annual bill impact for Non-Bill Assisted customers was $15.75 during the first year, $6.02 during the second year and $29.11 during year-three of the decoupling evaluation period.

Table IV.8: Residential Natural Gas (Sch. 23 & 53) Bill Impacts (Annual) – DR 30.11

Three Year Residential Annual Bill Impact				
	Year 1	Year 2	Year 3	Average
Bill Assisted				
Usage (Therms)	727	602	641	641
Total bill	$ 840.24	$ 720.53	$ 783.56	$ 783.56
Bill excluding Schedule 142	$ 825.95	$ 714.31	$ 756.47	$ 756.47
Schedule 142 bill Impact	$ 14.29	$ 6.22	$ 27.09	$ 27.09
Schedule 142 bill impact (percent)	1.73%	0.87%	3.58%	3.58%
Non-Bill Assisted				
Usage (Therms)	787	648	697	697
Total bill	$ 899.46	$ 765.42	$ 842.89	$ 842.89
Bill excluding Schedule 142	$ 883.71	$ 759.40	$ 813.78	$ 813.78
Schedule 142 bill Impact	$ 15.75	$ 6.02	$ 29.11	$ 29.11
Schedule 142 bill impact (percent)	1.78%	0.79%	3.58%	3.58%

For Bill Assisted customers, the Schedule 142 impact percentage was 1.73% during the first year, 0.87% in year two and 3.58% in year three. For Non-Bill Assisted customers the percentage impact was $1.78%, 0.79%, and 3.58% respectively for each of the three years. Considering the cumulative rate change over three years, the percentage impact on natural gas Bill Assisted residential customers average bills was 6.18%; the cumulative impact on Non-Bill Assisted customers was. 6.15%. Annual and monthly percentage impacts are equivalent.

Table IV.9 presents a comparison of the relative bill impacts of the Schedule 142 rates on Bill Assisted and Non-Bill Assisted residential natural gas (Schedules 23 & 53) customers. The overall conclusion is that energy usage by Bill Assisted and Non-Bill Assisted natural gas customers is essentially similar. While impacts were very similar for the two groups, the Bill Assisted customers experienced slightly lower bill impacts during two of the three years of evaluation. On average for natural gas residential customers, over the three-year evaluation period, Bill Assisted customer's Schedule 142 impact was 6.44% less than the impact on Non-Bill Assisted customers because the Bill Assisted natural gas customers use slightly less energy.[24]

Table IV.9: Bill Assisted vs. Non-Bill Assisted Residential Natural Gas (Sch. 23 & 53) Impact – DR 30.11

Three Year Average Schedule 142 Gas Bill Impacts				
Average Monthly Impact				
	Non-Bill Assisted	Bill Assisted	Difference	% Difference
Year 1	$ 1.31	$ 1.19	$ (0.12)	-9.25%
Year 2	$ 0.50	$ 0.52	$ 0.02	3.31%
Year 3	$ 2.43	$ 2.26	$ (0.17)	-6.93%
Average	$ 1.41	$ 1.32	$ (0.09)	-6.44%
Average Annual Impact				
	Non-Bill Assisted	Bill Assisted	Difference	% Difference
Year 1	$ 15.75	$ 14.29	$ (1.46)	-9.25%
Year 2	$ 6.02	$ 6.22	$ 0.20	3.31%
Year 3	$ 29.11	$ 27.09	$ (2.02)	-6.93%
Average	$ 16.96	$ 15.87	$ (1.09)	-6.44%

Table IV.10 illustrates the monthly usage patterns for Bill Assisted and Non-Bill Assisted customers over the three-year evaluation period.

[24] The energy comparison here is not carried down to the next level of analysis, which could standardize for household size and housing type. This means that the analysis at the top level may mask an underlying "mixture" problem.

Table IV.10: Bill Assisted and Non-Bill Assisted Natural Gas Usage Trends (Schedules 23 & 53) – DR 30.11

Three Year Residntial Gas Usage Trend													
Year One Usage (Therms)													
	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Annual
Bill Assisted	21.50	19.70	19.10	40.36	69.15	110.37	109.39	110.88	90.93	66.60	42.00	27.34	727.33
Non-Bill Assisted	17.03	17.71	25.46	66.66	92.56	134.38	120.28	113.76	86.58	57.44	31.64	23.63	787.14
Difference	4.47	1.99	-6.36	-26.30	-23.40	-24.01	-10.89	-2.88	4.35	9.15	10.37	3.71	-59.81
% Difference	20.79%	10.08%	-33.28%	-65.18%	-33.84%	-21.75%	-9.95%	-2.60%	4.78%	13.74%	24.68%	13.57%	-8.22%
Year Two Usage (Therms)													
	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Annual
Bill Assisted	20.70	17.63	18.78	24.80	56.29	92.90	97.10	80.48	71.11	56.07	41.38	24.65	601.88
Non-Bill Assisted	17.80	16.45	20.25	37.26	94.33	106.23	101.41	75.01	70.33	59.12	31.32	18.90	648.42
Difference	2.90	1.18	(1.47)	(12.46)	(38.04)	(13.33)	(4.31)	5.46	0.78	(3.04)	10.06	5.75	(46.53)
% Difference	14.00%	6.68%	-7.85%	-50.26%	-67.58%	-14.35%	-4.44%	6.79%	1.09%	-5.43%	24.31%	23.33%	-7.73%
Year Three Usage (Therms)													
	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Annual
Bill Assisted	17.67	16.96	19.99	30.58	57.24	100.51	114.00	90.03	78.74	55.61	32.24	27.09	640.67
Non-Bill Assisted	15.53	16.58	24.94	39.83	98.40	117.31	117.18	86.98	83.22	43.15	31.30	22.30	696.73
Difference	2.14	0.38	-4.95	-9.25	-41.16	-16.80	-3.18	3.06	-4.48	12.46	0.93	4.79	-56.06
% Difference	12.13%	2.23%	-24.76%	-30.24%	-71.90%	-16.71%	-2.79%	3.39%	-5.69%	22.40%	2.89%	17.69%	-8.75%

Monthly usage is very similar for the two groups, with Bill Assisted customer usage slightly lower than usage for Non-Bill Assisted customers each year by -7.73% to -8.75%. Figure IV.4 presents the seasonal usage patterns for Bill Assisted and Non-Bill Assisted residential natural gas (Schedules 23 & 53) customers during the three-year evaluation period. The curves overlap in the spring and summer. Bill Assisted customers use less natural gas in the fall and winter months.

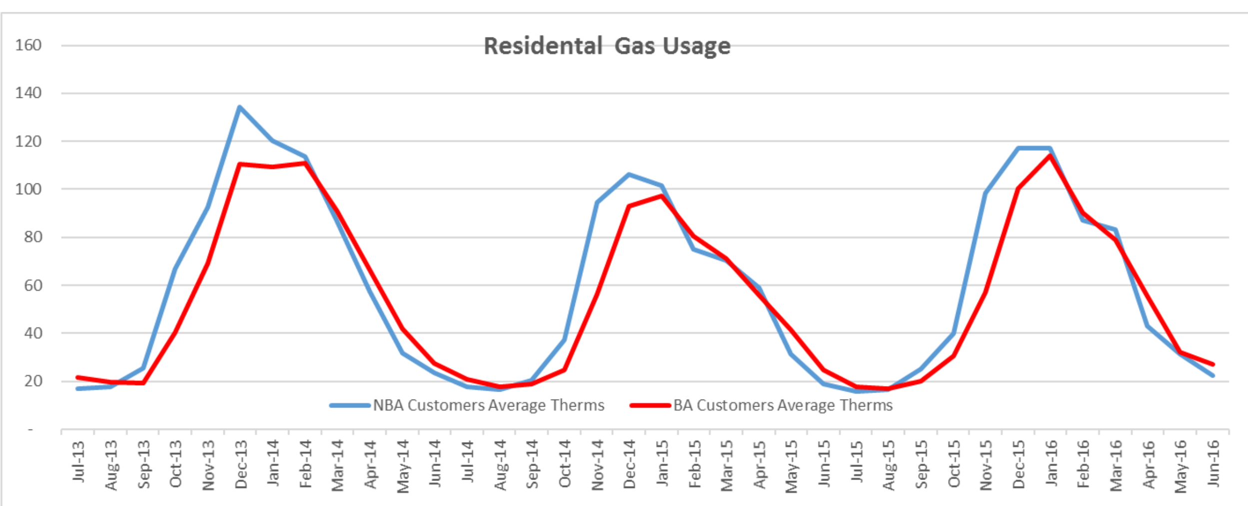


Figure IV.4: Monthly Bill Assisted & Non-Bill Assisted Residential Gas (Therms) (Sched. 23 & 53) – DR 30.11

Analysis of Energy Bill Assistance

To help alleviate energy costs PSE provides energy bill payment assistance through PSE HELP grants and other energy assistance grants funded by LIHEAP, Warm Home Fund, Native American tribes, faith-based groups and other government organizations. This report documents trends in low-income energy assistance grants before and during the evaluation period. This analysis first presents a summary of trends in the PSE HELP program and then presents trends for other low-income bill assistance programs not funded but administered through PSE and provided to PSE low-income clients.

PSE Bill Assistance HELP Grants

The PSE HELP grant is the largest of the energy assistance grants provided through PSE. Table IV.11 and Table IV.12 summarize monthly and annual data[25] on total amounts and total number of PSE HELP grants for both electric and natural gas customers combined. Table IV.13 shows the size of average PSE HELP grants.

Table IV.11: PSE Help Grant Amounts – DR 30.63 & 30.69

Total PSE HELP Grants						
	July 10 - June 11	July 11- June 12	July 12 -June 13	July 13- June 14	July 14 -June 15	July 15- June 16
	Year -2	Year -1	Year 0	Year 1	Year 2	Year 3
July	$ 556,590	$ 918,828	$ 681,519	$ 966,485	$ 1,175,294	$ 961,743
August	$ 259,991	$ 542,297	$ 567,647	$ 801,797	$ 931,513	$ 772,642
September	$ 360,344	$ 466,554	$ 495,040	$ 1,193,071	$ 863,559	$ 832,072
October	$ 1,026,752	$ 1,487,285	$ 1,425,348	$ 1,386,091	$ 1,266,807	$ 1,524,406
November	$ 1,306,441	$ 1,827,937	$ 2,863,887	$ 1,987,101	$ 2,259,278	$ 2,252,935
December	$ 2,226,097	$ 1,499,644	$ 1,569,431	$ 1,577,810	$ 1,621,713	$ 1,766,211
January	$ 531,058	$ 754,986	$ 933,199	$ 947,911	$ 1,076,701	$ 1,092,033
February	$ 1,236,461	$ 647,193	$ 721,651	$ 960,561	$ 1,076,198	$ 1,254,770
March	$ 1,605,132	$ 865,968	$ 905,462	$ 1,160,024	$ 1,152,657	$ 1,435,666
April	$ 1,288,359	$ 1,240,873	$ 1,403,195	$ 1,355,061	$ 1,172,048	$ 1,053,777
May	$ 1,308,868	$ 1,165,010	$ 1,215,000	$ 1,390,138	$ 1,119,985	$ 1,146,390
June	$ 1,157,952	$ 985,467	$ 1,132,236	$ 1,707,370	$ 1,369,757	$ 1,248,462
Total	$ 12,864,045	$ 12,402,042	$ 13,913,615	$ 15,433,420	$ 15,085,510	$ 15,341,107

[25] The PSE HELP grant data in this section is organized to be consistent with the decoupling evaluation periods from (July 1 to June 30). The evaluation period annual bill assistance data may differ from annual bill assistance data that is compiled on a billing assistance program-year basis (October 1 to September 30).

Table IV.12: Number of PSE Help Grants – DR 30.63 & 30.69

Number of PSE HELP Grants						
	July 10 - June 11	July 11- June 12	July 12 -June 13	July 13- June 14	July 14 -June 15	July 15- June 16
	Year -2	Year -1	Year 0	Year 1	Year 2	Year 3
July	1,374	2,433	1,617	2,223	2,516	2,516
August	719	1,452	1,451	1,777	1,584	1,584
September	848	1,026	1,130	3,361	1,839	1,839
October	2,045	2,916	2,751	2,836	3,631	3,631
November	2,432	3,404	5,515	4,354	5,437	5,437
December	4,773	2,782	3,072	3,924	4,414	4,414
January	1,209	1,805	2,104	2,963	3,104	3,104
February	2,890	1,697	1,778	3,124	3,390	3,390
March	3,884	2,223	2,271	3,487	3,789	3,789
April	3,256	3,233	3,582	3,407	2,821	2,821
May	3,411	3,065	2,889	3,084	2,863	2,863
June	3,040	2,163	2,566	3,504	3,089	3,089
Total	29,881	28,199	30,726	38,044	38,477	38,477

Table IV.13: Average PSE Help Grants – DR 30.63 & 30.69

Average PSE HELP Grant						
	July 10 - June 11	July 11- June 12	July 12 -June 13	July 13- June 14	July 14 -June 15	July 15- June 16
	Year -2	Year -1	Year 0	Year 1	Year 2	Year 3
July	$ 405.09	$ 377.65	$ 421.47	$ 447.35	$ 465.75	$ 418.11
August	$ 361.60	$ 373.48	$ 391.21	$ 479.05	$ 475.94	$ 446.10
September	$ 424.93	$ 454.73	$ 438.09	$ 435.17	$ 458.09	$ 452.11
October	$ 727.28	$ 510.04	$ 502.59	$ 498.22	$ 453.68	$ 409.38
November	$ 751.62	$ 537.00	$ 519.29	$ 498.67	$ 448.26	$ 420.84
December	$ 314.19	$ 539.05	$ 510.88	$ 483.70	$ 398.02	$ 394.09
January	$ 624.47	$ 418.27	$ 443.54	$ 411.54	$ 362.65	$ 355.71
February	$ 223.94	$ 381.37	$ 405.88	$ 388.39	$ 336.77	$ 374.03
March	$ 222.96	$ 389.55	$ 398.71	$ 372.19	$ 332.17	$ 371.94
April	$ 381.10	$ 383.81	$ 391.74	$ 374.41	$ 344.79	$ 385.18
May	$ 341.55	$ 380.10	$ 420.56	$ 401.18	$ 365.15	$ 398.19
June	$ 324.17	$ 455.60	$ 441.25	$ 440.01	$ 396.10	$ 418.61
Total	$ 389.92	$ 439.80	$ 451.58	$ 435.68	$ 398.48	$ 399.87

Figure IV.5 illustrates the trends in both PSE HELP grant amounts and number of grants. The grant amounts are measured on the right vertical axis and the number of grants is measured on the left vertical axis. After a decrease in 2012, both total grant amounts and the total number of PSE HELP grants began to increase in 2013 and 2014. The number of grants and the amounts given have remained stable over the three evaluation years 2014, 2015, and 2016.

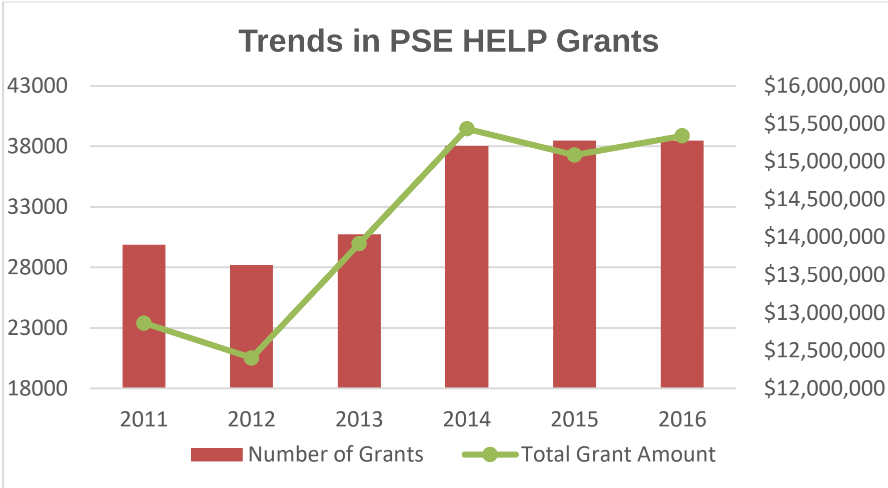


Figure IV.5: Six-Year Trend in Number and Total Amounts of PSE HELP Grants– DR 30.63 & 30.69

Figure IV.5: Six-Year Trend illustrates the trends in both PSE HELP grant amounts and number of grants. The grant amounts are measured on the right vertical axis and the number of grants is measured on the left vertical axis. After a decrease in 2012, both total grant amounts and the total number of PSE HELP grants began to increase in 2013 and 2014. The number of grants and the amounts given have remained stable over the three evaluation years 2014, 2015, and 2016. There is a clear decline in the average grant size from 2013 during six-year analysis (Figure IV.6). However, the average PSE HELP grant size stabilized from 2015 through 2016.

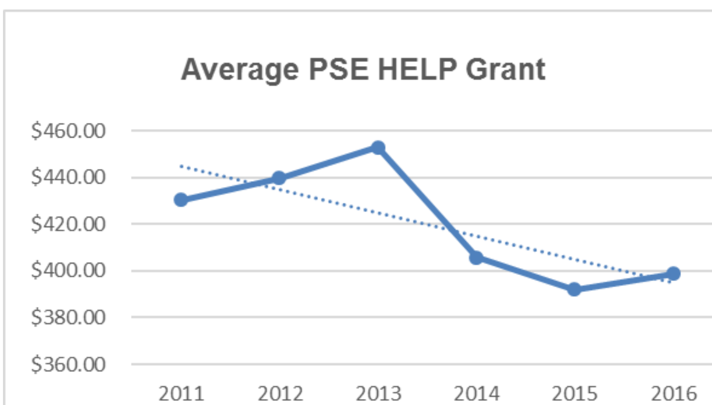


Figure IV.6: Trend in Average PSE HELP Grant – DR 30.63 & 30.69

Other PSE Administered Bill Assistance Grants

This section provides a broader view presenting trends of all the energy assistance grants administered through PSE but funded by other organizations. The multiple grants taken together present a more complete picture of bill payment assistance available to PSE customers.

Table IV.14 presents a six-year trend for the PSE HELP grants, LIHEAP grants, the Warm Home Fund and others including native American tribes, faith based organizations, and government organizations. The energy grant data used in this section was provided by PSE as response to DR 30.13_Att A 121697-UE 121705-UG PSE Resp GIL PEACH DR 30.13_Attach A, DR 30.63_Att A 121697-UE 121705-UG PSE Resp GIL PEACH DR 30.63_Attach A and DR 30.69_Att A 121697-UE 121705-UG PSE Resp GIL PEACH DR 30.69_Attach A and DR 30.69_Attachment A Supplemental Response.[26] Information based on energy assistance program-year is provided through 2016 based on billing assistance grants program-year October 1 through September 31[27].

Table IV.14: Bill Assistance Grants Administered Through PSE – DR 30.13, 30.63 & 30.69

Bill Assistance Grant Totals				
	LIHEAP	PSE HELP	Other	Total
2010	$ 14,098,800	$ 11,955,220	$ 6,470,171	$32,524,191
2011	$ 14,576,086	$ 13,614,799	$ 5,757,089	$33,947,974
2012	$ 11,119,822	$ 12,218,569	$ 4,415,259	$27,753,650
2013	$ 9,258,459	$ 15,130,762	$ 2,204,449	$26,593,670
2014	$ 9,836,285	$ 15,442,433	$ 4,211,120	$29,489,838
2015	$ 8,603,900	$ 14,681,601	$ 4,349,383	$27,634,884
2016	$ 8,717,759	$ 15,370,931	$ 5,735,622	$29,824,312

Figure IV.7 provides a graphic illustration of the trends in grant amounts. Total bill assistance grant funding decreased significantly between 2010 and 2013. Much of the decline is attributed to the decrease in the LIHEAP grant, which declined from over $14,098,800 in 2010 to $9.258,459 in 2013, a decrease of $4,840,341 or -34%. The PSE HELP grant has helped fill the gap in the LIHEAP funding reduction with increase in funding from $11,955,220 in 2010 to $15,370,931 in 2016, an increase of $3,415,711 or 29%. The PSE bill assistance grants began to exceed the LIHEAP grants in 2012 and this trend has continued through 2016.

[26] DR 30.69 has an initial response plus a supplemental response (providing additional months of data). Where the response to DR 30.69 is citied, to supplemental response is also included in the analysis.

[27] Energy assistance grant data for this analysis of all bill assistance grants administered by PSE is reported on the basis of the energy assistance program-year, which extends from October 1 to September 31. The energy assistance program year is different from the decoupling evaluation year, which extends from July 1 to June 30. The evaluation period bill assistance data may differ from bill assistance data compiled on the basis of the energy assistance program year.

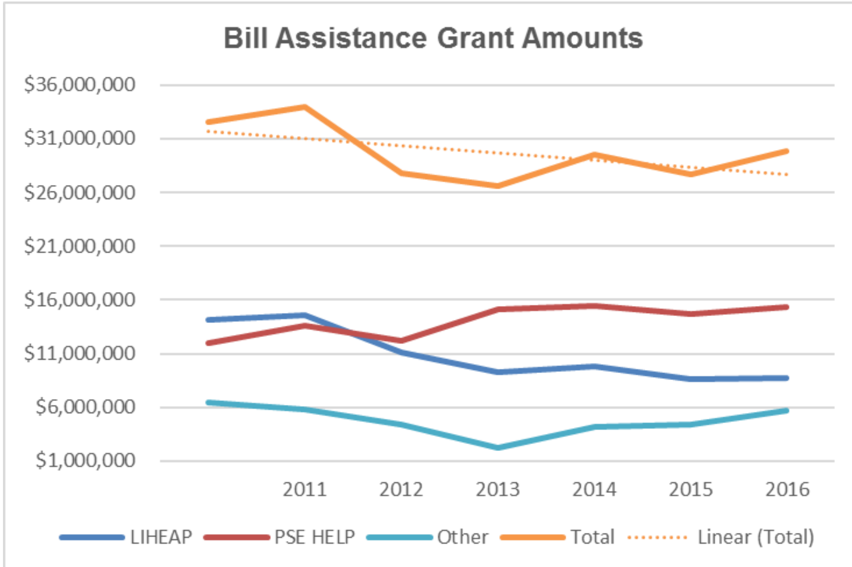


Figure IV.7: Trends in Bill Assistance Grant Amounts – DR 30.63 & DR 30.69

Figure IV.8 presents the trends in both grant amounts and number of grants for all bill assistance programs taken together. The grant total amounts are measured on the right vertical axis and the number of grants is measured on the left vertical axis. After a significant decrease in 2012 and a slight decrease in 2013, both total grant amounts and the total number of grants increased in 2014 and began to drop again in 2015 and 2016.

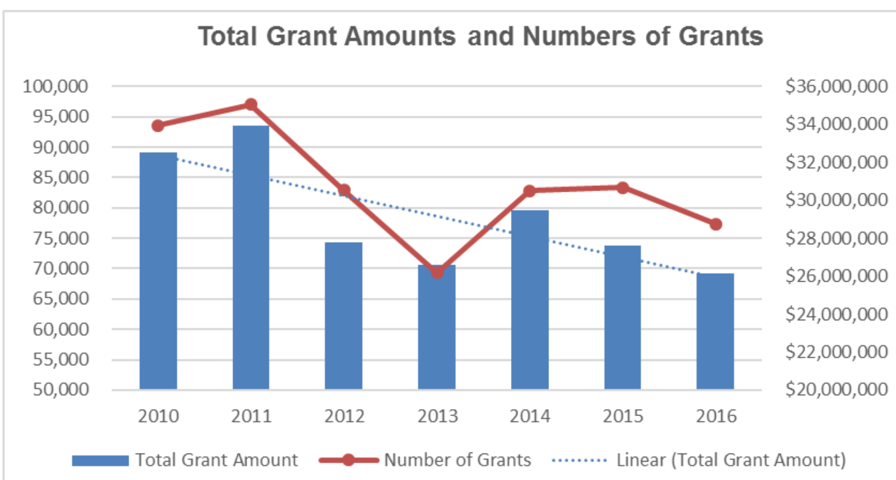


Figure IV.8: All Grant Programs - Grant Amounts and Number of Grants – DR 30.63 & 30.69

Table IV.15 presents a breakdown of the number of bill assistance grants from all funding sources. The number of LIHEAP grants decreased by 10,421 grants from 34,018 to 23,597 or 31% between 2010 and 2013. During the 2010 to 2013 period the number of PSE HELP grants increased by 6,738 from 27,151 to 33,889 or 25%. From the period

2013 to 2016 the number of LHEAP grants increased by 2,170 and the number of PSE grants increased by 3,783. The number of other grants decreased from 32,388 to 11,830 or 63% between 2010 and 2013. Trends in the other grants category also reversed direction after 2013 and increased from 11,830 to 22,532 or 90% between 2013 and 2016. The total number of grants decreased from 93,557 to 69,316 between 2010 and 2013. The negative trend in total grants also reversed in 2013 as the number of grants increased by 16,583 or 24% between 2013 and 2016.

Table IV.15: Trends in Number of Bill Assistance Grants Administered by PSE – DR 30.63 & 30.69

Number of Bill Assistance Grants				
	LIHEAP	PSE HELP	Other	Total
2010	34,018	27,151	32,388	93,557
2011	35,986	31,851	29,183	97,020
2012	26,325	27,486	29,089	82,900
2013	23,597	33,889	11,830	69,316
2014	25,031	35,341	22,436	82,808
2015	24,566	37,238	21,552	83,356
2016	25,767	37,600	22,532	85,899

Figure IV.9 illustrates the trends in average bill assistance grant size over the six-year period. The average grant size for all grants combined has remained fairly stable at $348 per grant in 2010 and $347 in 2016. Bill assistance data presented for comparison of all grants administered by PSE is based on a program year October 1 to September 30.

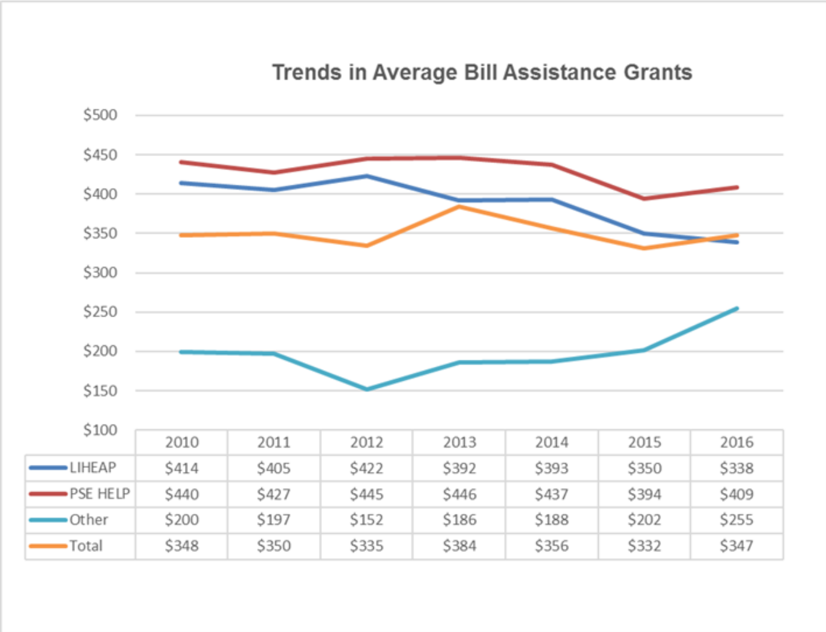


Figure IV.9: Trends in Average Bill Assistance Grants – DR 30.63 & 30.69

Low Income Out-of-Pocket Analysis

The section addresses Bill Assisted customers' out-of-pocket expenditures for energy provided by the PSE. All data in this section is based on the PSE decoupling year July-June rather than the energy assistance program year. For the purposes of this analysis, out-of-pocket expenditures are defined as the average annual bill for a Bill Assisted customer less the average PSE HELP grant.[28]

Table IV.16 presents an analysis of the average annual PSE HELP grant compared to the average annual energy bill for Bill Assisted customers during the three-year decoupling evaluation period. Natural gas and electric customer impacts are analyzed separately because the average PSE HELP grant and the average energy bill is different for gas and electric customers.

On average, electric Bill Assistance customer's out-of-pocket expenditure for energy services was $745.04 or 63% of the average energy bill. For natural gas customers, the average out-of-pocket expenditure was $467.32 or 60% of the average energy bill. Electric customers receive larger HELP grants but they also pay a higher percentage of their bill out-of-pocket. The percentage out-of-pocket decreased after the first year of decoupling and increased slightly after the second year for both natural gas and electric Bill Assisted customers.

Table IV.16: Low Income Out-of-Pocket Energy Expenditures – DR 30.11 & 30.69

PSE Bill Assisted Customer Impact				
Electric	**Year 1**	**Year 2**	**Year 3**	**Average**
Average Bill	$ 1,294.39	$ 1,060.42	$ 1,205.37	$ 1,186.73
Schedule 142 Bill Impact	$ 14.29	$ 6.22	$ 27.09	$ 15.87
Average Annual PSE HELP Grant	$ 470.57	$ 424.42	$ 430.08	$ 441.69
Out-of-Pocket Expenditures	$ 823.82	$ 636.00	$ 775.29	$ 745.04
% Out-of-Pocket Expenditures	64%	60%	64%	63%
Natural Gas				
Average Bill	$ 840.24	$ 720.53	$ 783.56	$ 781.44
Schedule 142 Bill Impact	$ 21.00	$ 24.20	$ 57.91	$ 34.37
Average Annual PSE HELP Grant	$ 337.61	$ 315.89	$ 288.88	$ 314.13
Out-of-Pocket Expenditures	$ 502.63	$ 404.64	$ 494.68	$ 467.32
% Out-of-Pocket Expenditures	60%	56%	63%	60%

[28] Note that a household with both PSE electric and natural gas services has two PSE accounts and may receive HELP benefits for both accounts.

Out-of-pocket expenditures declined slightly for both electric and natural gas customers over the three-year decoupling evaluation period, however the size of the decline is small and showed an increase from the second to the third year. Figure IV.10 and Figure IV.11, respectively, illustrate changes in out-of-pocket expenditures for electric and natural gas Bill Assisted customers.

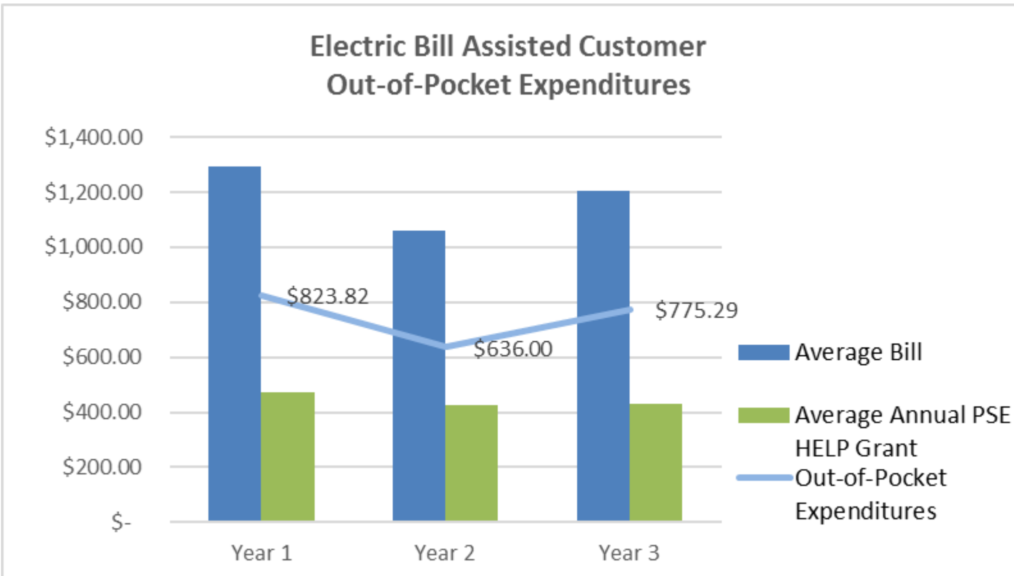


Figure IV.10: Trends in Average Electric PSE HELP Grants – DR 30.63 & 30.69

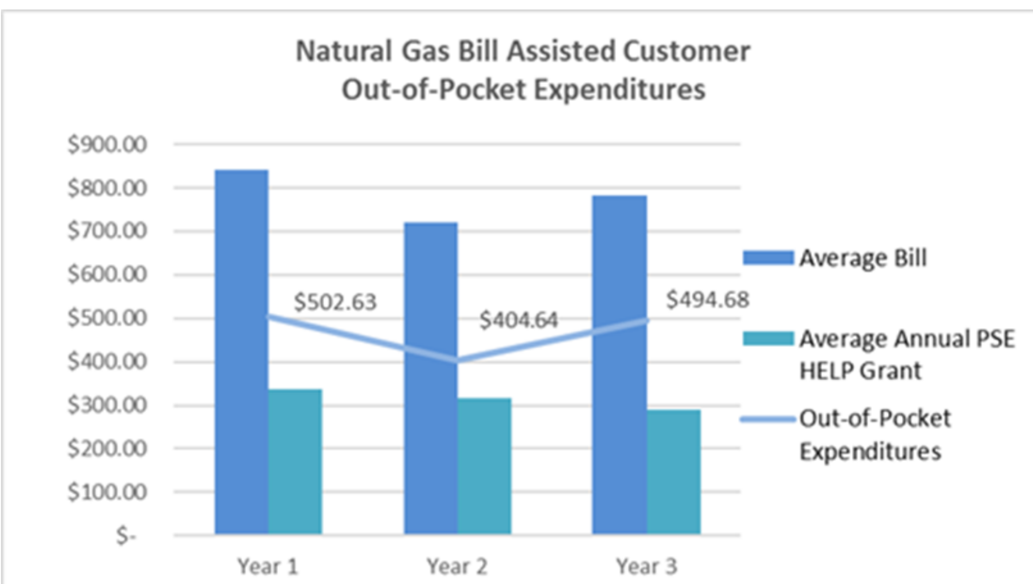


Figure IV.11: Trends in Average Natural Gas PSE HELP Grants – DR 30.63 & 30.69

Approximate Analysis of Weatherization Expenditures

An approximate analysis of Low-Income Weatherization Expenditures is shown for natural gas low-income (Table IV.17), non-low-income natural gas homes (Table IV.18) and for the full natural gas portfolio excluding low-income (Table IV.19).

Table IV.17: Cost per Therm – Gas Low-Income Weatherization – Exhibit 1

Natural Gas Low-Income Residential Programs (Actual)			
Year	**Expenditures**	**Savings Achieved, Therms**	**Ratio of $/Therm**
2011	$ 712,248	50,745	14.04
2012	$ 378,512	22,622	16.73
2013	$ 372,176	32,948	11.30
2014	$ 305,326	24,370	12.53
2015	$ 268,098	18,815	14.25

Table IV.18: Cost per Therm - Other Natural Gas Residential Programs – Exhibit 1

Natural Gas Non-Low-Income Residential Programs (Actual)			
Year	**Expenditures**	**Savings Achieved, Therms**	**Ratio of $/Therm**
2011	$ 5,687,204	1,595,632	3.56
2012	$ 5,725,705	1,730,229	3.31
2013	$ 5,940,964	1,568,247	3.79
2014	$ 6,807,747	1,737,216	3.92
2015	$ 6,679,463	1,450,130	4.61

Table IV.19: Cost per Therm – Total Gas Portfolio (Except Low-Income) – Exhibit 1

Total Portfolio: Natural Gas, Less Low-Income Weatherization (Actual)			
Year	**Expenditures**	**Savings Achieved, Therms**	**Ratio of $/Therm**
2011	$ 13,824,592	5,135,976	2.69
2012	$ 12,062,430	5,181,878	2.33
2013	$ 10,590,046	6,505,513	1.63
2014	$ 10,286,692	3,551,815	2.90
2015	$ 10,685,478	3,062,011	3.49

Funding Changes

The change in low-income residential weatherization spending from 2013 to 2014 is shown in Table IV.20, for 2013 to 2014, in Table IV.21 for 2014 to 2015, and for 2015-2016 in Table IV.23. An overall perspective for the three years is provided in Order 07, which is referenced to the Multi-Party Agreement and directs this change in funding[29] As a part of the Settlement Agreement (as directed by the Commission), PSE added $500,000 to the 2014 Schedule 201 Electric Program Budget and $100,000 to its Schedule 201 investor contribution.[30] These budgets support weatherization of low-income houses (Table IV.20). Note that the actual increase is larger than the $500,000 amount.[31] These are additions recur yearly, through the term of the rate plan.

Table IV.20: Change in Low-Income Weatherization Budget with Initiation of Decoupling – DR 20.39

Low-Income Weatherization (2013 vs. 2014)				
Source	**2013**	**2014**	**Difference**	**Percentage**
Electric Tariff	2,425,462	3,098,684	673,222	27.8%
Gas Tariff	301,309	369,443	68,134	22.6%
Shareholder Contribution	300,000	400,000	100,000	33.3%
Total	3,028,784	3,870,141	841,356	27.8%

As shown in Table IV.21, the second Evaluation Year showed a small net addition to the budget for the tariff schedules, inclusive of an increase of 7.1% for Electric Schedule 201 and a 27.4% decrease for natural gas Schedule 201.

With somewhat different numbers (since the shareholder contribution is not included), the *PSE Conservation Savings Goals and Budgets* links the budgets with anticipated energy savings. Table IV.21 shows the planning contrast for 2015 vs. 2014 low-income Schedule 201 weatherization. As shown in the table, there was a spending drop for gas weatherization of about 27% and a spending increase for electric weatherization of about 7% from 2014 to 2015. This result is consistent with the pattern in Table IV.23.[32]

[29] Paragraphs 177 and 178; pages 76 and 77 of Order 07, Dockets UE-121697 and UG-121705 (consolidated), Dockets UE-130173 & UG-130138 (consolidated), dated June 25, 2013.

[30] Source: Response to H. GIL PEACH & ASSOCIATES Data Request No. 01.19.

[31] Source for Table IV.20 is Response to H. GIL PEACH & ASSOCIATES Data Request No. 20.39.

[32] Source for Table IV.24 Planning Exhibit 1's.

Table IV.21: Change in Low-Income Weatherization Funding from First to Second Decoupling Year

Low-Income Weatherization (2014 vs. 2015)				
Source	**2014**	**2015**	**Difference**	**Percentage**
Electric Tariff	3,098,684	3,318,140	219,456	7.1%
Gas Tariff	369,443	268,098	-101,345	-27.4%
Shareholder Contribution	400,000	400,000	0	0.0%
Total	3,870,141	3,988,253	118,111	3.1%

Table IV.22: Change in Low-Income Weatherization Funding from Second to Third Decoupling Year – DR 30.39

Low-Income Weatherization (2015 vs. 2016)				
Source	**2015**	**2016**	**Difference**	**Percentage**
Electric Tariff	3,318,140	3,386,625	68,485	2.1%
Gas Tariff	268,098	283,478	15,380	5.7%
Shareholder Contribution	400,000	400,000	0	0.0%
Total	3,988,253	4,072,119	83,866	2.1%

Table IV.23: Change from beginning of Decoupling through Third Year – DR 20.39 & 30.39

Low-Income Weatherization (2013 vs. 2016)				
Source	**2013**	**2016**	**Difference**	**Percentage**
Electric Tariff	2,425,462	3,386,625	961,163	39.6%
Gas Tariff	301,309	283,478	-17,831	-5.9%
Shareholder Contribution	300,000	400,000	100,000	33.3%
Total	3,028,786	4,072,119	1,043,333	34.4%

The net change in funding for weatherization from the year prior to decoupling through the end of the third year of decoupling is an addition of 1,043,333 (34.4%), as shown in

Table IV.23. There is an overall increase in electric funding and a small decrease in gas funding, for an overall increase in low-income weatherization funding during the three years of decoupling.[33]

Table IV.24: 2014-2015 Low-Income Spending & Savings (Conservation Rider Goals and Budgets) - Exhibit 1

Low-Income Weatherization						
Grouping	**Year**	**Electric Program Budgets**	**Natural Gas Program Budgets**	**Energy Savings (kWh)**	**Energy Savings (Therms)**	**Number of Households Served**
	2014	3,098,684	369,443	1,571,000	27,391	Not Available
	2015	3,318,140	268,098	1,571,000	18,815	Not Available
Change ($)		219,456	-101,345	0	-8,576	
Change (%)		7.1%	-27.4%	0.0%	-31.3%	

Using PSE Conservation Savings Goals and Budgets information (Table IV.25), for regular residential programs there was a budget decrease of 1% for electricity conservation between 2014 and 2015. Non-Bill Assisted residential natural gas (Schedules 23 & 53) conservation programs (Table IV.25) saw a decrease of about 11.5% from 2014 to 2015.[34]

[33] Source for Table IV.23 Response to H. GIL PEACH & ASSOCIATES Data Request No. 20.39 & Response to H. GIL PEACH & ASSOCIATES Data Request No. 30.39.

[34] Source for Table IV.25: Planning Exhibit 1's.

Table IV.25: 2014-15 Regular Res. Spending & Savings (Conservation Rider Goals and Budgets) – Exhibit 1

Residential Programs (Except Low-Income Weatherization)						
Grouping	**Year**	**Electric Program Budgets**	**Natural Gas Program Budgets**	**Energy Savings (kWh)**	**Energy Savings (Therms)**	**Number of Households Served**
Regular Residential	2014	42,006,316	6,362,648	131,817,000	1,639,166	Not Available
	2015	44,356,173	6,679,863	130,451,000	1,450,131	Not Available
Change ($)		2,349,857	317,215	-1,366,000	-189,035	Not Available
Change (%)		5.6%	5.0%	-1.0%	-11.5%	Not Available

Table IV.26: 2015-2016 Low-Income Spending & Savings (Conservation Rider Goals and Budgets) – Exhibit 1

Low-Income Weatherization						
Grouping	**Year**	**Electric Program Budgets**	**Natural Gas Program Budgets**	**Energy Savings (kWh)**	**Energy Savings (Therms)**	**Number of Households Served**
	2015	3,318,140	268,098	1,571,000	18,815	Not Available
	2016	3,386,625	283,479	1,560,000	18,641	Not Available
Change ($)		68,485	15,381	-11,000	-174	
Change (%)		2.1%	5.7%	-0.7%	-0.9%	

Table IV.27: 2015-2016 Regular Res. Spending & Savings (Conservation Rider Goals and Budgets – Exhibit 1

Residential Programs (Except Low-Income Weatherization)						
Grouping	**Year**	**Electric Program Budgets**	**Natural Gas Program Budgets**	**Energy Savings (kWh)**	**Energy Savings (Therms)**	**Number of Households Served**
	2015	44,356,173	6,679,863	130,451,000	1,450,131	Not Available
	2016	42,089,341	7,076,049	131,489,000	1,839,996	Not Available
Change ($)		-2,266,832	396,186	1,038,000	389,865	
Change (%)		-5.1%	5.9%	0.8%	26.9%	

From 2015 to 2016, low-income spending for both electricity and natural gas increased, while energy savings for both decreased very slightly (Table IV.26). For residential programs other than low-income, the electric-program budget decreased while the natural gas program-budget increased. Electric energy savings increased slightly while gas savings increased substantially (Table IV.27).

Customers Served

Information on customers served was not available.

Modifications to Low-Income Conservation Programs

For low-income programs, there have been no changes to client program eligibility.[35] Puget Sound Energy defers to the Washington State Department of Commerce on issues related to client eligibility.[36] Similarly, there have been no substantial changes to low-income weatherization programs and measures.[37] In the second evaluation year, PSE began operating its electric program in accordance with the revised WAC 480-109-100(10). Since this revision does not affect the installation of prescriptive measures, it has no effect on low-income weatherization (LIW) electric conservation.

However, this WAC revision provides utilities with the option of funding low-income conservation projects that have been deemed by implementing agencies (State-appointed entities allowed to install conservation measures in low-income dwelling units) to be cost-effective and consistent with the Weatherization Manual (maintained by the Washington Department of Commerce).[38] This change allows utilities to classify low-income projects that meet a Savings to Investment Ratio (SIR ratio) of => 1.0 as cost-effective, based on the state approved Targeted Retrofit Energy Analysis Tool (TREAT).[39] PSE began compliance with the revised rule in June 2015.

[35] Source: Responses to H. GIL PEACH & ASSOCIATES Data Requests Nos. 30.10, 20.17, 20.09, 01.14 and 1.20).

[36] Source: Response to H. GIL PEACH & ASSOCIATES Data Request No. 01.20.

[37] Source: Response to H. GIL PEACH & ASSOCIATES Data Request No. 01.15.

[38] In addition to weather normalization, TREAT audit software has a provision for entering in the previous twelve months of energy use information for a dwelling and the program can use this information to ratio its prediction of the amount of energy savings. This feature partially corrects for the tendency of USDOE approved audit software to substantially over-predict energy savings by providing an empirical true-up to actual home usage for the model.

[39] Source: Response to H. GIL PEACH & ASSOCIATES Data Request No. 20.40. TREAT is a software product of Performance Systems Development, http://psdconsulting.com/software/treat/.

Section Summary

Bill impacts, payment assistance, weatherization, and program budgets are summarized below. These are followed by an overall summary for this section of the study.

Bill impacts

Schedule 142 applies equally, although not in relation to ability to pay, to low-income and non-low-income customers because PSE does not have a separate low-income rate. Electric bill impacts for non-low-income and low-income residential customers over the three decoupling years were small, but growing (Table IV.3). The same pattern exists for natural gas bill impacts (Table IV.7). These increases in bills would have occurred with or without decoupling.[40] Low-income electric customers use essentially the same, but slightly more kWh than non-low-income electric customers, so their bills tend to be slightly higher (Figure IV.2). Low-income gas customers tend to use essential the same, but slightly under less gas than non-low-income gas customers (Figure IV.4) so their bills are slightly lower. These differences in bills are not meaningful.

The total grant amount available to low-income customers is substantially less today than prior to decoupling. This is due to the reduction of federal LIHEAP funding, which had been temporarily increased due to the Great Recession. PSE has substantially increased the funding for HELP grants but this does not make up the loss of LIHEAP funding. In response to these changes, there has been a tendency toward giving lower grant amounts in order to be able to provide grants to more low-income customers.

Weatherization Spending

With regard to energy efficiency for Billing Assisted customers, there was a substantial increase in weatherization program funding (about 28%) from 2013 to 2014 for both gas and electricity. From 2014 to 2015, Billing Assisted gas funding dropped by about 27% while electric funding increased by almost 7%. Due to the relative sizes of the Bill Assisted electric and gas programs, overall this was an increase from 2014 to 2015 of about 3% (Table IV.24: 2014-2015 Low-Income Spending). In contrast, from 2014 to 2015, funding for Non-Bill Assisted residential energy efficiency programs rose 5.6%

[40] To be clear, we assert that the revenue requirement is a real number in the material world and that the decoupling mechanism approaches this number (otherwise the mechanism would not have been approved and put into operation). Alternatively, there might have been one or more traditional rate cases in which PSE would have had the burden to demonstrate its costs and revenues to justify one or more rate increases. The task of either a decoupling approach or a rate case approach (or of any other acceptable approach) would be to approximate as closely as possible the actual revenue requirement. In order to challenge this technical perspective, a party would need to demonstrate a different revenue requirement, not simply assert that the outcome of an alternative approach is unknown because the traditional rate case alternative did not occur in the real world.

for electricity and 5% for natural gas (Table IV.25). Overall, from 2013 to 2015 (from before decoupling to the close of the third decoupling year) funding for low-income weatherization rose 34.4%, with a strong increase in electric funding and a small decline in natural gas funding (Table IV.23).

Weatherization

There were no changes to the low-income weatherization program, except a WAC revision that may allow processing of some additional low-income weatherization as cost-effective. For weatherization, in terms of dollars per unit of conserved energy achieved, cost is rising per unit of energy savings for electric programs. This trend is shown for low-income weatherization (Table IV.20) and non-low-income residential (Table IV.21). Cost in dollars per unit of conserved energy achieved is only slightly higher for natural gas programs. Cost for natural gas low-income weatherization is shown in Table IV.17 and for gas residential non-low-income in Table IV.18. These changes are independent of decoupling and are typical of the ending of a particular program "wave."

Program budgets

Overall, the budgets for low-income weatherization have increase 34.4% over the three decoupling years. This includes a substantial increase in electric funding (39.6%), a decrease in gas funding (-5.9%) and an increase in the shareholder contribution of 33.3%). The overall budget increase is $1,043,333 (Table IV.23).[41]

[41] With regard to energy efficiency for Billing Assisted and Non-Billing Assisted customers, there was a substantial increase in Billing Assisted weatherization program funding (about 28%) from 2013 to 2014 that affected gas and electricity, relatively to the same degree. Pursuant to the Commission's Order, PSE increased annual billing-assistance funding for low-income customers by $1,000,000 (recurring each year during the term of the rate plan) plus the average increase in residential rates from Schedule 142. In addition, PSE increased funding for low-income residential weatherization by $500,000 (recurring each year during the term of the rate plan), plus a shareholder contribution of $100,000 per year.

V. Trends in Conservation Performance

Task elements 4 and 5 deal with trends in the performance of the Company's electric and gas conservation programs since the inception of the decoupling mechanisms. Here we report program performance, other trends and other indicators.

Figure V.1: Conservation Performance

Task Elements 4 & 5: Identity Trends in Performance Identification of conclusive trends in the performance of the Company's electric and gas conservation programs since the inception of the decoupling mechanism (based on information already available as part of the Company's biennial conservation achievement evaluations filed with the Commission in the second quarter of every "even" calendar year). Trends could include: changes in senior management roles as they relate to energy efficiency, numbers of presentations to the Board, significant changes in the program budgets or savings levels as reported.

Program Performance

Budgets with projected and achieved energy savings are shown for electricity conservation programs in Table V.1 and for natural gas conservation programs in Table V.2.

- Savings goals have declined for both electricity and gas programs during the decoupling years. This was also the pattern prior to decoupling.
- Performance (in terms of MWh and millions of dollars saved) consistently exceeds goals. This was also the general pattern prior to decoupling.
- The costs per conserved kWh and per conserved therm have varied, but have tended to increase during decoupling (Table V.3 & Table V.4).

- Since beginning decoupling, PSE has met the goal of achieving more than its EIA target. A conservation goal was established in 2002 in a Stipulation Agreement and, again in 2010, with the enactment of the EIA.

- In nominal terms, for electric DSM (Table V.1), there was a meaningful increase in the DSM budget in the year prior to decoupling, a decrease in the year decoupling started and a small increase in 2014 (the first full budget year during decoupling).[42] Then, there was a further small increase for 2015 and a small decrease for 2016. There is no evidence of a conclusive trend.

- In nominal terms, for conservation of natural gas (Table V.2), the budget for natural gas DSM had a sharp decrease in 2012 (down about 30% from 2011); then decreased by only about two percent (2%) in 2013; then by nearly ten percent (10%) in 2014. Then the budget increased by about 12% in 2015, and by over 10% for 2016. Program funding for 2016 is slightly more than spending planned for 2013 (an increase of about 1%). This means there is essentially no net change for gas for 2016. Yearly budgets do not show a conclusive change.

- In (approximate) real terms, the overall program budget has increased by less than one percent in contrast to the budget in the year prior to decoupling. The electricity budget decreased by less than one-tenth of one percent and the gas budget increased 7.3%. Overall, since gas sales are considerably less than electricity sales, the blended total represents an increase of 0.8% in contrast to the year prior to decoupling (Table V.5).

- In overview, for both electricity and natural gas, there is no clear pattern of change in conservation program performance against goals during decoupling vs. prior to decoupling. In both cases, performance is good.

[42] NEEA savings are included in both the "MWh Goal" and "MWh Saved" totals as part of the overall Energy Efficiency portfolio for each year. See Response to H. GIL PEACH & ASSOCIATES Data Request No. 20.52.

Table V.1: Electricity Conservation Budgets & Goals – DR 20.15, 30.18 & Exhibit 1

Conservation Rider: Electric Budget												
Year	**Residential**	**Business**	**Regional Efforts**	**Support**	**Pilots**	**Other Electric Programs**	**EES Research & Compliance**	**Total**	**% Change in Total Budget**	**MWh Goal**	**MWh Saved**	**Achieved vs. Goal**
2011	$ 32,965,589	$ 46,433,266	$ 5,260,640	$ 4,618,636	$ -	$ 1,515,773	$ -	$ 90,793,904		340,119	348,926	102.6%
2012	$ 42,699,404	$ 41,841,180	$ 5,260,640	$ 3,514,281	-	$ 1,648,961	$ 3,171,946	$ 98,136,412	8.09%	336,600	339,500	100.9%
2013	$ 42,477,000	$ 38,522,000	$ 5,261,000	$ 3,568,000	$ -	$ 835,000	$ 3,738,000	$ 94,401,000	-3.81%	333,520	361,400	108.4%
2014	$ 45,105,000	$ 36,638,496	$ 5,260,640	$ 3,358,605	$1,572,459	$ 399,763	$ 3,485,575	$ 95,820,538	1.50%	344,405	378,500	109.9%
2015	$ 47,674,312	$ 32,672,929	$ 4,771,922	$ 5,575,677	$1,267,712	$ 3,638,342	$ 3,806,632	$ 99,407,526	3.74%	277,605	282,500	101.8%
2016	$ 45,475,966	$ 35,390,334	$ 5,200,000	$ 6,096,731	$ 976,899	$ 1,765,586	$ 3,154,491	$ 98,060,007	-1.36%	NA	NA	NA

Note: For a complete representation of PSE's annual conservation savings and expenditures by program, please see Section X (Reference Appendix I), an extract of PSE's "Exhibit 1: Savings and Expenditures" from its Annual Report of Energy Conservation Accomplishments.

Table V.2: Natural Gas Conservation Budgets & Goals – DR 20.15, 30.18 & Exhibit 1

Conservation Rider: Natural Gas Budget											
Year	**Residential**	**Business**	**Regional Efforts**	**Support**	**Pilots**	**EES Research & Compliance**	**Total**	**% Change in Total Budget**	**Millions of Therms Goal**	**Millions of Therms Saved**	**Achieved vs. Goal**
2011	$11,039,916	$6,952,079	$0	$1,228,461	$0	$0	$19,220,456		4.79	5.19	108.4%
2012	$6,936,722	$5,291,990	$0	$537,252	$0	$632,221	$13,398,185	-30.29%	4.86	5.20	107.0%
2013	$6,863,000	$4,987,000	$0	$554,000	$0	$777,000	$13,181,000	-1.62%	4.65	6.54	140.6%
2014	$6,732,091	$3,925,110	$0	$609,988	$248,630	$411,323	$11,927,142	-9.51%	3.88	4.35	112.1%
2015	$6,947,561	$4,006,015	$738,000	$914,537	$233,902	$482,420	$13,322,435	11.70%	3.08	3.24	105.2%
2016	$7,359,528	$4,748,313	$1,086,677	$829,632	$181,029	$508,537	$14,713,716	10.44%	NA	NA	NA

Note: For a complete representation of PSE's annual conservation savings and expenditures by program, please see Section X (Reference Appendix I), an extract of PSE's "Exhibit 1: Savings and Expenditures" from its Annual Report of Energy Conservation Accomplishments.

Table V.3: Cost per Conserved kWh – DR 20.15 & Exhibit 1

Electricity Saved & Unit Cost			
Year	**MWh Saved**	**Total Budget**	**Dollars per kWh**
2011	348,256	$ 90,793,904	0.26
2012	339,500	$ 98,136,412	0.29
2013	361,400	$ 94,401,000	0.26
2014	378,500	$ 95,820,538	0.25
2015	277,605	$ 99,407,526	0.36

Note: Based on actual kWh and planning budget.

Table V.4: Cost per Conserved Therm – DR 20.15 & Exhibit 1

Natural Gas Saved & Unit Cost			
Year	**Millions of Therms Saved**	**Total Budget**	**Dollars per Therm**
2011	5.19	19,220,456	3.70
2012	5.20	13,398,185	2.58
2013	6.54	13,181,000	2.02
2014	4.35	11,927,142	2.74
2015	3.24	13,322,435	4.11
Note: Based on actual kWh and planning budget.			

Table V.5: Nominal and Approximate Real Budget Change – DR 20.15, 30.18 & Exhibit 1

Three Decoupled Years: Budget Change				
Program Budget	**2013**	**2016**	**Change**	**% Change**
Nominal				
Electric	94,401,000	98,060,007	3,659,007	3.9%
Gas	13,181,000	14,713,716	1,532,716	11.6%
Total	107,584,013	112,773,723	5,191,723	4.8%
Approximate Real (BLS CPI)				
Electric	98,177,040	98,060,007	(117,033)	-0.1%
Gas	13,708,240	14,713,716	1,005,476	7.3%
Total	111,885,280	112,773,723	888,443	0.8%
Note: The Bureau of Labor Statistics CPI Calculator (BLS CPI-U) equates the buying power of one dollar in 2013 to the buying power $1.04 in 2016. See: http://data.bls.gov/cgi-bin/cpicalc.pl).				

In the background, one of the factors influencing gas conservation is the relative decrease in commodity cost of natural gas due to fracking. This lowers avoided cost and so reduces cost-effective economic potential when using the required cost tests. This is also the general trend in the US and follows the dramatic increase in the production of fracked gas. From the approaching gas scarcity of not many years ago, the US has become the major producer of natural gas (Figure V.2).[43] With the increased abundance of supply, cost has decreased.

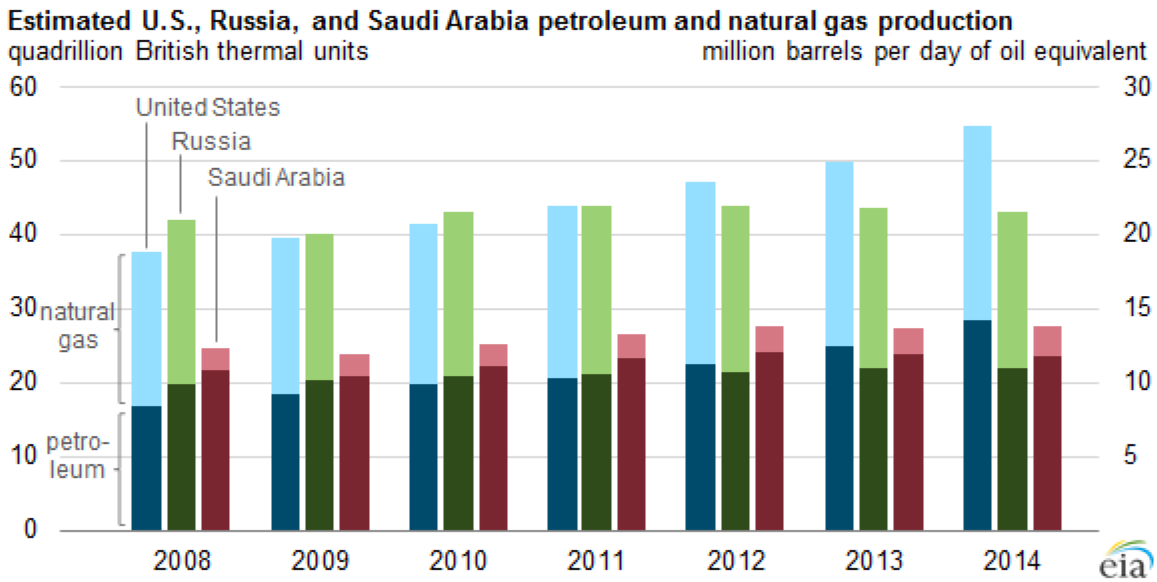


Figure V.2: U.S. Becomes Largest Producer of Natural Gas (EIA).

PSE is now a major contributor to NEEA's regional gas market transformation program. PSE participates in and is a major funder of the Natural Gas Advisory Committee

Other Trends

While there have been no net structural changes in senior management roles since decoupling was initiated,[44] PSE shifted the reporting of its director of Energy Efficiency from the Vice-President of Corporate Affairs to a newly-appointed Vice-President of Customer Solutions. In June 2016, The Vice-President of Customer Solutions resigned and now the Director of Energy Efficiency reports to the Senior Vice-President of Customer Experience and Chief Customer Officer. These are the organizational changes for the three-year study. They appear not to be related to performance.

[43] Source: Energy Information Administration (http://www.eia.gov/todayinenergy/detail.cfm?id=20692).

[44] Interpretation of Responses to H. GIL PEACH & ASSOCIATES Data Request No. 01.22, DR 20.19 and DR 30.19.

There have been no Energy Efficiency department-specific presentations to the PSE Board of Directors since decoupling (the last was in 2008).[45] PSE operates a Customer Energy Management Group, along with ancillary services (including Market Research, Resource Planning, and Marketing) staffed with a combined FTE of approximately 120 to cover all functions for delivery of energy efficiency and low-income assistance services.

There were no meaningful changes to staffing for Energy Efficiency or to staffing for Low-Income Weatherization or Bill Assistance for the first Evaluation Year.[46] There was one meaningful change for the second evaluation year: the Renewables organization, consisting of the Green Power Program (a revenue neutral O&M program) and Net Metering (the Conservation rider funds administrative costs) was added to the Residential Energy Management organization. This is meaningful because it begins to indicate a possible breaching of silos as part of an industry trend.[47] This change occurred in decoupling, but it might alternatively have occurred outside of decoupling since the combination of Energy Efficiency and Renewables is an industry trend.

Other Indicators

There is a positive outlook on decoupling among PSE management and staff. From the perspective of Puget Sound Energy, these are some positive results from decoupling:[48]

(1) By removing the "throughput incentive" in which a substantial portion of fixed costs was recovered through volumetric energy sales, any financial disincentive to encourage its customers from engaging in energy efficiency efforts has been mitigated.

(2) Second, decoupling removes the financial disincentive so that the Company can support customers' engagement with rooftop solar and other distributed

[45] Responses to H. GIL PEACH & ASSOCIATES Data Request No. 01.23, DR 20.22 and DR 30.20.

[46] Interpretation of Response to H. GIL PEACH & ASSOCIATES Data Request No. 01.29.

[47] California, New York, Massachusetts and the National Association of Regulatory Utility Commissioners (NARUC) exemplify the industry trend of classification of Energy Efficiency and Renewables within the category of Distributed Energy Resources (DERs). In the NARUC guide, "A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE)." *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*, Prepared by the Staff Subcommittee on Rate Design, 2016.

[48] Response to H. GIL PEACH & ASSOCIATES Data Request No. 01.32 and observation/discussion.

generation projects that enable customers to have more control over energy needs, providing value to customers in terms of reduction of customer bills and to society in terms of environmental improvements.[49,50]

These advantages take on increased value for effective grid management.[51]

In addition, we note that, in interviews, we were told that in previous years the emphasis had been on *reaching* targets. Now, when a program *exceeds* its target, the program manager and team can keep going. They report no indication of any perception by executive management of a problem in exceeding targets and attribute this to decoupling since any financial disincentive is removed. Prior to this, Energy Efficiency management consistently encouraged Program Staff to actively manage programs to maximize energy savings within programs, but this is different from exceeding targets. The first has to do with getting the best return for a planned program target, the second with moving beyond that goal.[52]

[49] Robust solar is included in Puget Sound Energy's new Integrated Resource Plan.

[50] Reviewers note that this comment coupling conservation with distributed generation is not within scope. For example, that a net metering customer is fundamentally different from a customer that merely pursues energy conservation without combining energy conservation with a distributed energy resource. Also, a reviewer notes that the study does not provide data to demonstrate that decoupling is the right mechanism to address issues associated with distributed energy resources. We agree that the DSM silo does not traditionally incorporate distributed energy resources but elsewhere we are working on projects that have moved past this barrier. Facing forward, we advocate breaking silos as a general practice in order to increase value and monetize benefits. On the cost reduction and improved service potential of breaking down silos, see: Tett, Gillian, *The Silo Effect: The Peril of Expertise and the Promise of Breaking Down Barriers*. New York: Simon & Schuster, 2015.

[51] A reviewer, in review of the first Evaluation Year decoupling study raised the question of whether this statement about "added value" in the current industry disruptive process is germane to the evaluation of PSE's mechanism, and, instead, may be an unrelated policy argument. We are simply noting the fact that PSE's decoupling specifically *takes on added value* in the context of the current disruption of markets occurring in several jurisdictions and in the global context of climate adaptation.

[52] These two statements may appear contradictory: staff now feels more openness to exceed targets yet in the past management also encouraged maximizing energy savings. However, maximizing energy savings can mean making programs as efficient and effective as possible within a target, while exceeding targets means proceeding through targets so we see the statements as complementary. The change here is not "black and white", but it is a kind of "greenlight". Specifically, activity is greenlighted without a "Decoupling 2.0" revenue flow to monetize a reward (to serve as a "demand-pull" for the utility). In other words, we are talking here about a subtle change in organizational culture. A reviewer notes an alternative interpretation: PSE maximized acquisition of energy efficiency prior to decoupling and maximizes it today. We feel there is a subtle difference and a new "greenlight"; however, we agree that the effect is small.

PSE adaptively manages its programs and portfolio on a consistent basis – this is a key requirement, especially since PSE is the only IOU that proactively adjusts its UES-measure savings values *annually*. Additionally, PSE releases all-comers RFPs for new and existing outsourced conservation programs, and tries to work collaboratively and transparently with the CRAG to develop and report on conservation achievements. Over the past several years, Energy Efficiency management supported new and innovative marketing strategies (such as "Rock the Bulb", "Re-Energized by Design", and the recent "Energy Upgrades"), leading-edge programs and pilots (web-enabled thermostats, Energy Reporting pilots), and embraced new technologies (ductless heat pumps, heat pump water heaters, LEDs and T-LEDs, for example). PSE discusses its conservation achievements in detail in *Annual Reports of Energy Conservation Achievements*, filed with the Commission by March 1st each year. As an organization, PSE was active in moving conservation forward prior to decoupling and is continuing that trend in decoupling.

The change reported in discussions with energy efficiency staff is a subtle change of nuance in organizational culture. There was not a negative view of exceeding targets and there were no negative consequences for exceeding the electric or gas savings targets and goals. Still, in large and complex organizations, for staff to know that executive management will not see any negative consequences, financial or otherwise, in exceeding energy efficiency goals creates a sense of positive assurance to staff that they are aligned with management in doing so. Utility organizational culture is very careful in nature. Within this kind of organizational context, decoupling creates a kind of "green light."[53]

Section Summary

Conservation performance is good, much the same in decoupling as it was prior to decoupling. Approximately real budgets are not much different from the year prior to decoupling. Decoupling removes barriers to energy conservation by increasing certainty of revenue recovery but it does not create a positive "pulling force" by monetizing part of the value of conservation in the form of new incentives for the utility. PSE's leadership and staff tend to support deregulation and see positive benefits.

[53] A reviewer, in commenting on the study for the first Evaluation Year, suggested that this section is overly speculative and/or makes policy arguments that are not appropriate for this evaluation, and so should be revised or removed. If we had no experience with organizational analysis or with the cultures of gas, electric and water utilities as operating organizations, then such a section might be overly speculative. However, we do have substantial experience in these areas. Decoupling does not occur in a vacuum; the context for decoupling is a policy context conditioned by the material reality of the need for energy conservation. We report what we see as a kind of pattern recognition from which readers may make policy arguments.

VI. Identification of Any Adverse Impacts

Task element 6 in the Amended Petition is focused on the possibility of adverse impacts caused by or associated with decoupling (Figure VI.1).

Task Element 6: Identification of Any Adverse Impacts

Identification of any conclusive evidence to suggest that the decoupling mechanisms adversely impacted customer service, distorted price signals for customers resulting in lower participation in conservation programs, or eroded the utility's incentive to control costs and improve operational efficiency.

Figure VI.1: Identify Adverse Impacts

What Adverse Impacts Might There Be?

Generally, any reform may have unanticipated and unintended consequences. One possible consequence of decoupling has been speculated to be a drop in the level of customer services. Another is a customer response to decoupling price signals, which increase price in the following cycle if there is less energy use than planned in the current cycle. Then, there is the area of cost control and operational efficiency – with increased surety of revenue recovery and the drives associated with a sales mentality removed, would staff become less oriented to cost control and would efficiency decline? The answer to each of these sub-questions is "No". The variations in cost caused by the adjustment mechanism are too small to negatively affect conservation. Some of the service indicators, however, are negative. We interpret this as due to difficult weather in 2015, but suggest this as an area to watch for 2016 and 2017. The possible adverse impacts could be at the conservation level or more broadly at the company level. The one unanticipated and unintended consequence was cumulative deferral due to the interaction of the 3% yearly rate cap and the weather sensitivity of natural gas residential decoupling group (Schedules 23 & 53). This interaction drives one result: delaying revenue recovery for more than two years. Delayed revenue recovery has an effect on GAAP accounting. Whether these results are perceived as adverse impacts depends upon perspective.

The Need to Look for Unintended Consequences

In ethics, a fundamental question is "how can a thing that is quite apparently good also have negative consequences?" Or, in an organizational analysis, a root question is, "how can a change that is clearly functional also entail dysfunctional consequences?" In economic analysis, it is not unusual for economists to estimate the value of a forest in terms of equivalent dollar value of lumber while treating the ecosystem as an externality. In evaluation, we are required to look for unintended and adverse impacts of regulatory reforms.[54]

Large integrated utilities have strong internal planning so utility personnel can often see the future better than people in other kinds of organizations that do not make the same kinds of investment in forecasting and planning functions. This is a major strength. Yet because regulated utilities are a kind of profit-oriented business and carry out an essential public service function, which would otherwise be a requirement of government, they can be subject both to classic problems of market failure and to classic problems of government failure.[55] It is only by application of intelligence and strict internal discipline that they avoid problems. Looking for unintended consequences and adverse impacts is part of that discipline.

[54] For example, required testing in schools tends to undermine the value of the tests. "The more any quantitative social indicator is used for social decision-making, the more subject it will be to corruption pressures and the more apt it will be to distort and corrupt the social processes it is intended to monitor." Campbell, D.T., Assessing the Impact of Planned Social Change, *Evaluation and Program Planning*, 1979, 2, 67-90. Planning economists have put it this way: If the state sets indicators for performance to a production plan but enforces the results on the indicators with heavy consequences (such as liquidation of the manager for failure to meet plan targets), production processes tend to meet or excel on the officially adopted indicators while losing other qualities that may be essential to customers such as durability or fitness for use. See Heilbroner, Robert, "Socialism," in *The Concise Encyclopedia of Economics* (http://www.econlib.org/library/Enc1/Socialism.html). In sociotechnical analysis, there is the similar contradiction of "normal accidents" in complexly interactive technical systems – in complex systems, the more the possibilities for interaction among components (the "interactive complexity" of system) and the more "tightly coupled" (in the sense of a change in one element leading to a direct change in others automatically), the more likely there will be an unanticipated accident. Moreover, incremental "fixes" (designed to eliminate "human errors" in order to prevent some kinds of accidents) increase interactive complexity; and so, without meaning to, increase the probability of an unanticipated accident. Perrow, Charles, *Normal Accidents, Living with High-Risk Technologies*. Princeton, New Jersey: Princeton University Press, 1999 (first published by Basic Books, 1984).

[55] Cowen, Tyler, *The Theory of Market Failure, A Critical Examination*. Fairfax, Virginia: George Mason University Press, 1988; Wallis, Joe & Brian Dollery, *Market Failure, Government Failure, Leadership and Public Policy*. London: MacMillan Press Ltd., 1999 & New York City: St. Martin's Press, 1999; Wolf, Charles (Jr.), *Markets or Governments, Choosing Between Imperfect Alternatives, Second Edition*. Cambridge, Massachusetts & London: MIT Press, a RAND book, first published in 1988, third printing 1997.

We will look here at customer service, price signals, cost control & operational efficiency, external factors, and cumulative deferrals. Cumulative deferral is an unintended rate consequence of the Schedule 142 decoupling mechanism. As observed, it is a function of short cycles in the weather (Section VII).

Customer Service

PSE has operated for many years using a series of service quality indices (SQI) and reliability measures.[56] These permit examination of customer service metrics over time. In examination of selected Puget Sound Energy Service Quality Index and Electric Service Reliability Reports for 2011, 2012, 2013, 2014 and 2015 (

Table VI.1 through Table VI.5) there is no evident pattern of adverse impact to customer service through the second year of decoupling.[57] However in 2015, four performance problems register in the service quality indicators. The measurement overlap of this data with Evaluation Years is partial, but enough time has passed so as to make the overlap unimportant for 2015. Indicators for 2016 will be available in 2017.

Customer Satisfaction

As shown in

Table VI.1, indicators of customer satisfaction usually exceed target levels. There is a dip for Quanta Gas in 2012, prior to decoupling and a dip in answering performance for the Customer Access Center for 2013 also prior to decoupling. This dip coincides with implementation of a new Customer Information System (CIS). We treat 2013 as the last year prior to initiation of decoupling (although there is an overlap). However,

[56] PSE's Response to H. GIL PEACH & ASSOCIATES Data Request No. 01.24, with Attachments A, B and C (service quality reports for 2011, 2012 and 2013; also, Response to H. GIL PEACH & ASSOCIATES Data Request No. 20.21, Attachment A (service quality report for 2014).

[57]

Table VI.1 through Table VI.5 are developed from information provided in PSE's Response to H. GIL PEACH & ASSOCIATES Data Request No. 01.24, with Attachments A, B and C (service quality reports for 2011, 2012 and 2013; also, Response to H. GIL PEACH & ASSOCIATES Data Request No. 20.21, Attachment A (service quality report for 2014) and Response to H. GIL PEACH & ASSOCIATES Data Request No. 30.21, Attachment A (2015 Annual Puget Sound Energy Service Quality and Electric Service Reliability Report).

during decoupling, the answering performance indicator fails to meet target again in 2015.[58]

[58] PSE's response to H. GIL PEACH & ASSOCIATES Data Request No. 30.64 notes that "The decoupling mechanism was not a direct or remote cause of the 2015 performance result. As shown on page 12 of the 2015 Annual Puget Sound Energy ("PSE") Service Quality and Electric Service Reliability Report ("Report"), the 2015 performance result was negatively affected by the circumstances related to changing collection and disconnection procedures, unseasonal storms in August, technology system failures, and staffing issues."

Appointments

For appointments (Table VI.2) there is a drop below target for Service Provider Construction Appointments Kept – Quanta Gas for 2013, but the size of the drop (one percentage point) is not meaningful. We treat 2013 as the last year prior to decoupling (although there is an overlap). This indicator was not reported for 2014 and was on target for 2015.

Gas Operations

For gas operations

Table VI.3), there are no problems.

Electric Operations

Here (Table VI.4), one of the indicators is out of range and for that reason problematic. This occurs during decoupling in 2015.[59] .

Electric Service Reliability

For electric reliability (Table VI.5), both the SAIDI[60] and SAIFI[61] indicators are out of range for 2015 and therefore problematic.

In summary, review of PSE's service quality indicators shows four problematic indicators, all in 2015. The common element in the explanations for these indicators in the *2015 Annual Puget Sound Energy Service Quality and Electric Service Reliability Report* is weather. Weather would happen with or without decoupling and difficult weather years occur. If the 2015 results continue to show as part of a pattern in 2016 and 2017, there

[59] PSE's response to H. GIL PEACH & ASSOCIATES Data Request No. 30.64 notes that "The decoupling mechanism was not a direct or remote cause of the performance result. As indicated on page 24 of the Report, the 2015 performance result of 258 minutes was due to fewer available Quanta crews for the secondary incidents as more crews were assigned to emergency storm duty."

[60] PSE's response to H. GIL PEACH & ASSOCIATES Data Request No. 30.64 notes that: "PSE met the requirement of this measurement with the approval of the Washington Utilities and Transportation Commission ("WUTC") to exclude the catastrophic storms that occurred in August and November 2015. The WUTC order providing the exclusion can be found at the following link: https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=2074&year=2007&docketNumber=072300. PSE's customer report card with the final performance result of 272 minutes per customer per year can be found at: http://pse.com/accountsandservices/NewToPSE/Documents/2774_SQI_Report_Card_2015_wb.pdf."

[61] PSE's response to H. GIL PEACH & ASSOCIATES Data Request No. 30.64 notes that "$SAIFI_{5\%}$ <5% Non-Major Storm (< 5% customers affected) SAIFI: PSE met the requirement of this measurement. PSE's performance of 1.11 interruptions per customer per year for this measurement is better than the benchmark of 1.30 interruptions, *i.e.*, customers experienced, on average, 0.19 less interruptions than the benchmark."

should be a closer investigation. For now, we accept difficult weather as the core explanation.

Table VI.1: Indicators of Customer Satisfaction – DR 1.24, 20.21, 30.21

Measures of Service Quality 2011 - 2015 Indicators of Customer Satisfaction						
Key Measurement	**Benchmark/ Description**	**2011**	**2012**	**2013**	**2014**	**2015**
WUTC complaint ratio	No more tht 0.40 complaints per 1,000 customers, including all complaints filed with UTC	0.28	0.24	0.25	0.21	0.23
Customer Access Center transactions customer satisfaction	At least 90% satisfied (rating of 5 or higher on a 7-point scale)	0.95%	0.95%	91%	93%	94%
Field Service Operations transactions customer satisfaction	At least 90% satisfied (rating of 5 or higher on a 7-point scale)	0.96%	0.98%	95%	96%	96%
Service Provider Customer Satisfaction -- Pilchuck	At least 84% satisfied (rating of 5 of higheron a 7-point scale)	0.85%	Not Applicable (service provider changed)			
Service Provider Customer Satisfaction -- Quanta Electric	At least 77% satisfied (rating of 5 or higher on a 7-point scale)	0.81%	80%	NA	99%	Not Reported
Service Provider Customer Satisfaction -- Quanta Gas	At least 84% satisfied (rating of 5 of higheron a 7-point scale)	0.87%	82%	NA	99%	Not Reported
Customer Access Center answering performance	At least 75% of calls answered by a live representative within 30 seconds of request to speak with a live operator	0.77%	79%	66%	76%	70%
Note: Shaded cells show indicators registering below goal.						

Table VI.2: Appointments Indicators– DR 1.24, 20.21, 30.21

Measures of Service Quality 2011 - 2014: Operations Services - Appointments						
Key Measurement	**Benchmark/ Description**	**2011**	**2012**	**2013**	**2014**	**2015**
Appointments Kept	At least 92% of appointments kept	100%	100%	99%	100%	100%
Service Provider New Customer Construction Appointments Kept - Pilchuck	At least 98% of appointments kept	100%	NA - Service provider changed			
Service Provider New Customer Construction Appointments Kept - Quanta Electric	At least 98% of appointments kept	100%	99%	100%	Not Reported	99%
Service Provider New Customer Construction Appointments Kept - Quanta Gas	At least 98% of appointments kept	100%	98%	97%	Not Reported	98%
Note: Shaded cells show indicators registering below goal.						

Table VI.3: Indicators for Gas Operations – DR 1.24, 20.21, 30.21

Measures of Service Quality 2011 - 2015: Operations Services - Gas						
Key Measurement	**Benchmark/ Description**	**2011**	**2012**	**2013**	**2014**	**2015**
Gas Safety Response Time	Within 55 minutes from customer call to arrival of field technician	29 minutes	30 minutes	32 minutes	31 minutes	29 minutes
Secondary Safety Response Time - Pilchuck	Within 60 minutes from first response assessment completion to second response arrival	51 minutes	NA - Service provider changed			
Secondary Safety Response Time - Quanta Gas	Within 60 minutes from first response assessmente completion to second response arrival	53 minutes	48 minutes	46 minutes	47 minutes	46 minutes
Service Provider Standards Compliance - Pilchuck	At least 95% compliance with site audit checklist points	99%	NA - Service provider changed			
Service Provider Standards Compliance - Quanta Gas	At least 97% compliance with site audit checklist points	99%	98%	98%	98%	99%

Table VI.4: Indicators for Electric Operations – DR 1.24, 20.21, 30.21

Measures of Service Quality 2011 - 2015: Operations Services - Electric						
Key Measurement	**Benchmark/ Description**	**2011**	**2012**	**2013**	**2014**	**2015**
Electric Safety Response Time	Within 55 minutes from customer call to arrival of field technician	51 minutes	51 minutes	53 minutes	53 minutes	54 minutes
Service Provider Standards Compliance - Quanta Electric	At least 97% compliance with site audit checklist points	99%	98%	98%	98%	99%
Secondary Non-Emergency Safety Response and Restoration Time - Core Hour -- Quanta Electric	Within 250 minutes from the dispatch time to the restoration of non-emergency outage during core hours	234 minutes	239 minutes	243 minutes	248 minutes	258 minutes
Secondary Non-Emergency Safety Response and Restoration Time - Non-Core Hour -- Quanta Electric	Within 316 minutes from the dispatch time to the restoration of non-emergency restoratio of non-emergency outage during non-core hours.	273 minutes	270 minutes	274 minutes	282 minutes	297 minutes
Note: Shaded cells show indicators registering below goal.						

Table VI.5: Indicators of Electric Service Reliability – DR 1.24, 20.21, 30.21

Measures of Service Quality 2011 - 2015: Electric Service Reliability - SAIFI & SAIDI						
Key Measurement	**Benchmark/ Description**	**2011**	**2012**	**2013**	**2014**	**2015**
SAIFI(5%) <5% Non-Major Storm (< 5% customers affected)	No more than 1.30 interruptions per year per customer	1.02 interruptions	0.92 interruptions	0.86 interruptions	1.05 interruptions	2.18 interruptions
SAIDI (Total 5-Year Average) Total (all outages 5 year average)	No more than 320 minutes per customer per year	281 minutes	245 minutes	247 minutes	312 minutes	760 minutes
Note: Shaded cells show indicators registering below goal.						

Price Signals

Decoupling involves a projection of expected energy use for specific decoupling groups made up of rate schedules.[62] In the decoupling mechanism, when a group decreases energy usage so that the average for the group is below the planning projection, the decoupling adjustment will increase the group's cost per unit (cost per kWh; cost per therm; or cost per kW) for the next cycle.

- During the first Rate Year, only the K-factor (the projected percentage increase developed in the planning period) amount was collected for the first ten months of the year. This amount is not different from the amount that would have been collected in an ordinary rate increase for that period.

[62] An exception is that for Schedules 26 & 31 (only), the mechanism is based on projection of demand rather than energy.

- During the second Rate Year, deferral amounts were included in customer bills in addition to the K-factor. The very small bill increases when deferral amounts were included would not have signaled any advantage or disadvantage to participation in conservation programs.

- During the third Rate Year, rate and bill changes for some decoupling groups were larger but were still small.

For (only) two decoupling groups, the 3% cap came into play and limited bills. As a customer strategy, it remains true that participation in conservation programs can substantially lower bills and more than offset a number of small rate increases over a number of years. A small rate increase or decrease does not have a signal strength to outbalance the cost advantage of using fewer units. So, it does not provide a signal to disengage from energy conservation. The conclusion for the deferral adjustments for the first, second and third Evaluation Years is that there are *no adverse impacts on energy conservation from price signals*. This is not the same thing as being neutral: decoupling has a strong effect in removing barriers to conservation. But in a situation in which the utility is already doing a good amount of conservation, it is highly unlikely (given the strong positive pre-period) that an additional very small positive conservation effect could be detected, even if there were one. Though decoupling removes barriers, it does not create a “demand-pull.” There is no “pulling force” because it does not have the “Decoupling 2.0”[63] monetization of incentives for the utility. The obvious way to implement a demand-pull would be to include, within the design, the monetization of some of the conservation value as one or more new revenue streams to the utility.

Cost Control & Operational Efficiency

We have found no indication of any adverse effect of decoupling on the utility’s incentive to control costs. While conservation programs that exceed their targets or their planned expenditures are now not an automatic concern of executive management, we do not

[63] Decoupling 2.0 is a shorthand way that people working on evaluation of decoupling refer to the addition to the decoupling mechanism of a reliable new revenue stream for the utility for meeting or surpassing energy efficiency and conservation (and possibly including distributed energy resource, demand control or micro-grid) goals. These goals could be of any type. The critical concept is to create a “demand-pull” that creates a continuing revenue stream by monetizing some of the values attached to the goals. In discussion about decoupling, the kind of decoupling in play for PSE for the time window studied would be called “Decoupling 1.0”. If values of energy efficiency (and possibly including micro-girds, and other distributed energy resources than energy efficiency and demand control) were partially monetized to create a continuing payment stream to the utility, we call the combined package “Decoupling 2.0”.

classify this as an adverse impact but as a positive impact, since a goal of the decoupling pathway is to increase energy conservation.[64,65]

- Theoretically, by removing the focus on sales, utility executive management will be able to focus more effectively on other goals. Because cost recovery proceeds in a decoupled utility following a target revenue requirement that has already been projected in a commission proceeding, costs have been anticipated. So, a focus on cost control can function within this *already established revenue requirement* to improve earnings. PSE cannot increase profits by increasing sales, but can *only positively improve profits by improving cost control and operational efficiency*.[66]

- In our interactions with management and staff, we found no indications of any lack of attention to cost control and operational efficiency; we tested this with some direct questions. We believe that the company maintains a careful and prudent approach to controlling costs and we found no indication of any form of dysfunction or fractionalization within the organization.

[64] A reviewer, in its review of the study of the first Evaluation Year noted that PSE's budgets and targets for energy conservation were increasing year-over-year for most of the past decade.

[65] A reviewer, in its first Evaluation Year review, suggested that conservation spending is because these costs are passed directly through to the customers via the Schedule 120 tariff rider, and evaluation should take that into consideration. The evaluation team believes that increased conservation spending *is* one of a set of indicators of success and, actually, one of the primary indicators used to contrast the effects of decoupling. The BECAR studies are a place that provides third-party evaluative verification of conservation spending within the context of other indicators of program success, so any problem with conservation spending would be flagged there (and conservation claims would be adjusted for verification if there were a problem). For the validity of the conservation effect (including conservation spending as a component), this decoupling examination relies on the BECAR studies, which incorporate extensive conservation program evaluation including site visits. We take the pass-through of conservation costs to customers into account as the way utilities work. It is just a fact and is not a negative. The directive that energy conservation is a positive comes from the government of the State of Washington and from the WUTC policy on decoupling as well as from the realities of the material world and the rapidity of climate change; and from DSM being the least costly resource.

[66] A reviewer, in its review of the first Evaluation Year study, noted that it believes it is still imperative that PSE maintain proper cost controls for its conservation programs. The point we assert here is that decoupling provides increased incentive to maintain disciplined cost control. A reviewer raises the theoretical question of a utility that does not have an established revenue requirement, particularly one experiencing low load growth. Comments in review of the second Evaluation Year study state that a (theoretical) utility that does not have an established revenue requirement, particularly one experiencing low load growth, will have a stronger incentive to control costs in order to achieve its Return on Equity. PSE has been implementing operational efficiencies to control cost, presented in an update to the Commission on Decoupling and Rate Plan Efficiencies on August 28, 2014. In this plan, a number of cost reduction efforts are listed in three immediate areas: specific cost reductions, infrastructure reductions and improved financing factors. Longer-term process and technology efficiencies are also addressed. Also, a number of cost and service reports have been filed with the Commission. For information on these cost reduction efforts, please see PSE's Response to H. GIL PEACH & ASSOCIATES Data Request No. 04.01, dated May 7, 2015.

- We found dedication to high performance, individual and group achievement of strong technical proficiency and a sense of personal and business commitment to public service.

- We found no indication of any cynicism, apathy or disaffection during the formal workday or in informal discussions with management and staff. Staff holds each other, corporately, to high standards.

- The overall annual average increase in O&M is lower than the historical growth rate and has slowed compared to that presented in the ERF/Decoupling proceedings (2.0% versus 3.8%).[67] The electric annual growth rate in cost per customer of 3.5% is below the electric historical growth rate of 4.7% presented in the ERF/Decoupling proceedings. The natural gas annual growth rate represents a decrease in cost per customer at -0.7% compared to the 2.2% historical natural gas growth rate presented in the ERF/Decoupling proceedings.[68]

The commission structured the decoupling so as to provide PSE an improved opportunity to earn its authorized return, but set the decoupling mechanism in a way that require PSE to improve the efficiency of its operations in order to actually earn its authorized return.[69] This provides an incentive for cost control and to improve operational efficiency.

[67] See response to H. GIL PEACH & ASSOCIATES Data Request No. 30.37.

[68] See response to H. GIL PEACH & ASSOCIATES Data Request No. 20.36; including supporting tables in Attachment A. Also see the response to H. GIL PEACH & ASSOCIATES Data Request No. 20.37

[69] Dockets UE-1216907 and UG-121705 (consolidated), Order 07, Final Order Granting Petition and Dockets UE-13137 and UG-130138 (consolidated), Order 07, Final Order Authorizing Rates, Page 74, ¶171. Also, see Pages 89-90, ¶214-215.

As noted previously, in the discussion of service quality, the indicators are good, which is an indirect indication of operational efficiency. We find that, for the three years of decoupling, there is *no adverse impact on cost control or operational efficiency*.

External Factors: Accustomed Variation

This subsection attempts to establish normal variation in cost due to weather. Throughout this study, we look primarily for internal variables and particularly for "tractable" variables – variables that can be set or changed. But sometimes a factor outside of program control is important, such as weather.[70] Figure VI.2 shows average therms per residential customer per year. Figure VI.3 shows the contrasting result for normal weather.[71]

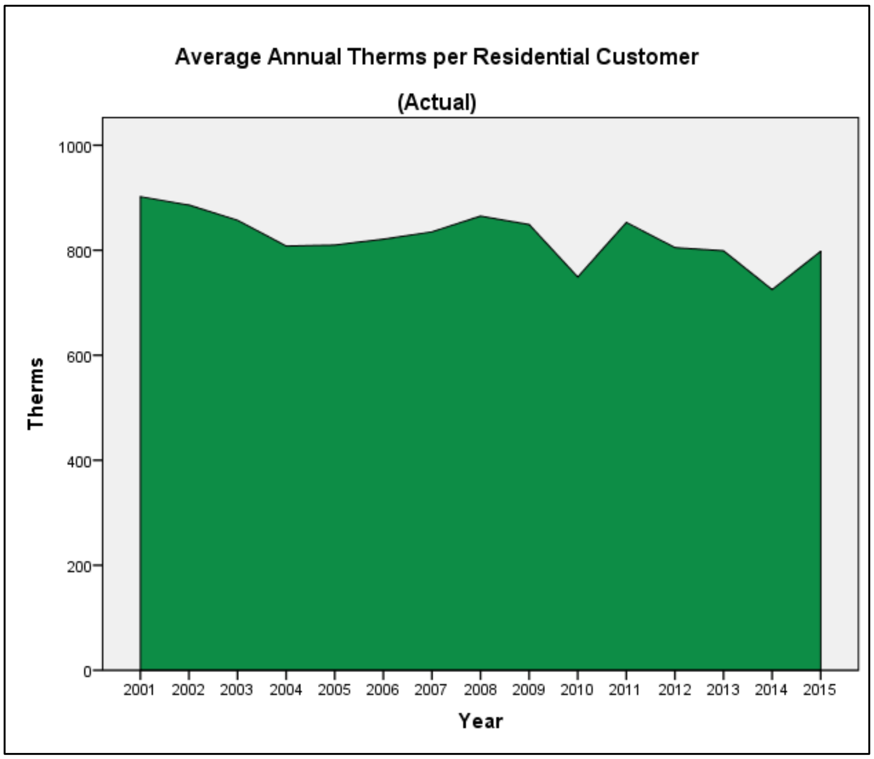


Figure VI.2: Actual Therms per Average Residential Natural Gas (Sch. 23 & 53) Customer – DR 30.29

[70] Only the residential sector is analyzed here because it is weather sensitive. The other sectors are either not weather sensitive or very much less so.

[71] Figure VI.2 through Figure VI.14 are developed on the Response to H. GIL PEACH & ASSOCIATES Data Request No. 30.29.

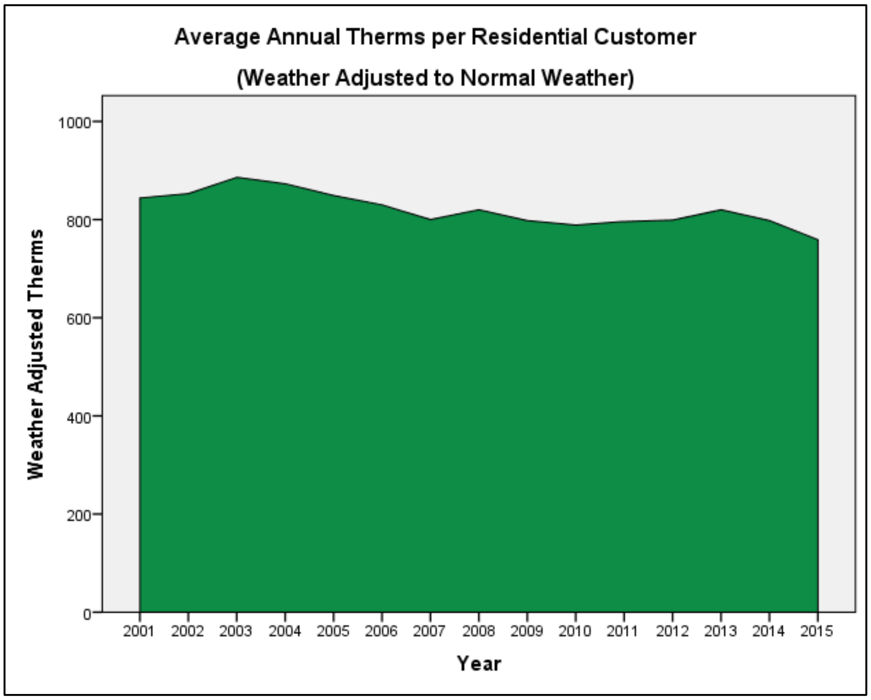


Figure VI.3: Normalized Therms per Average Residential Natural Gas (Sch. 23 & 53) Customer – DR 30.29

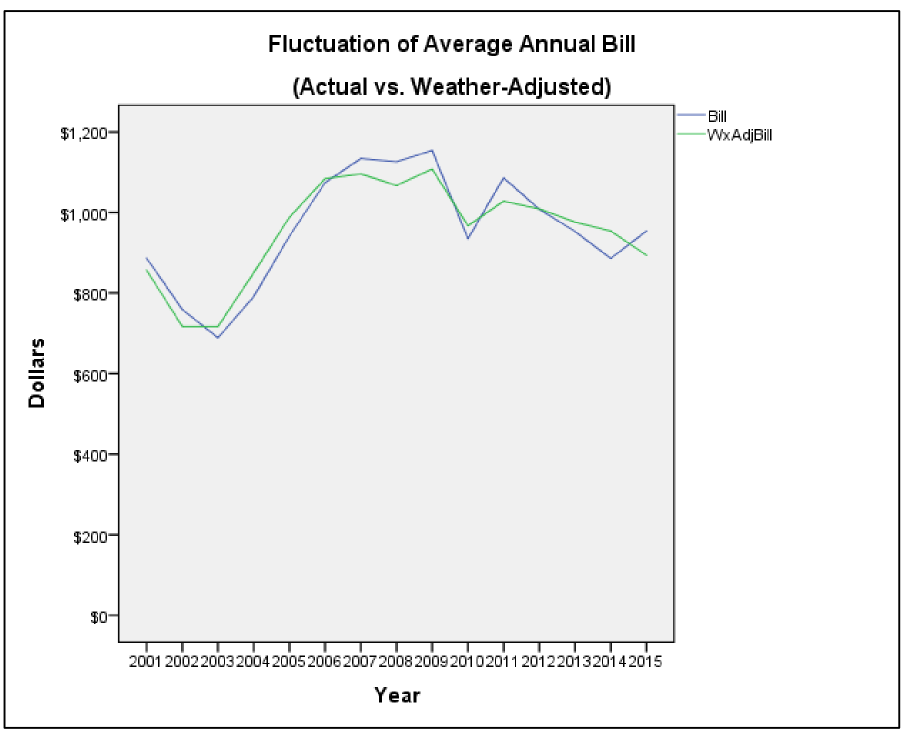


Figure VI.4: Average Annual Residential Customer Bill for Natural Gas (Sch. 23 &53) – DR 30.29

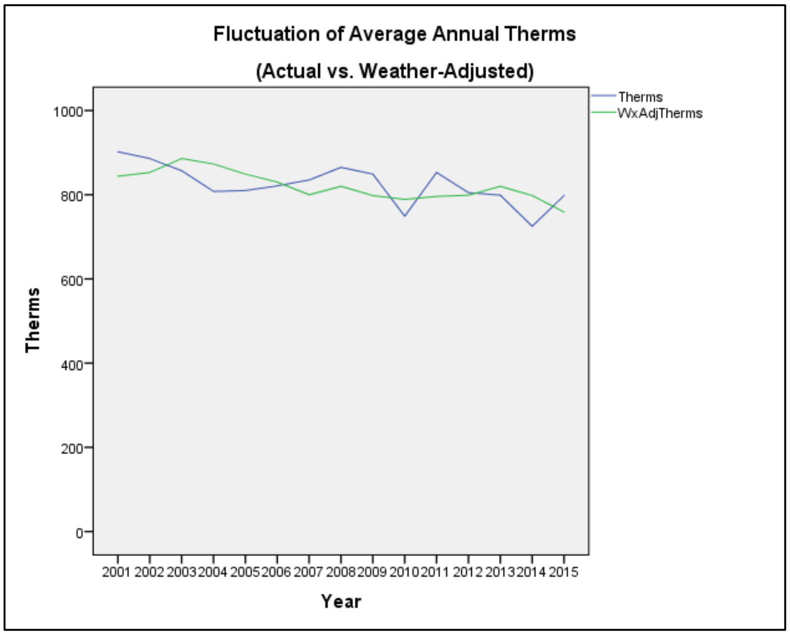


Figure VI.5: Comparison of Actual vs. Weather Normalized Therms per Year (Sch. 23 & 53) – DR 30.29

Figure VI.5 overlays Figure VI.2 and Figure VI.3 to provide a sharper contrast of normal weather variation. As shown in Figure VI.6, average yearly residential use of natural gas fluctuates within a band of plus or minus ten percent (+/- 10%).

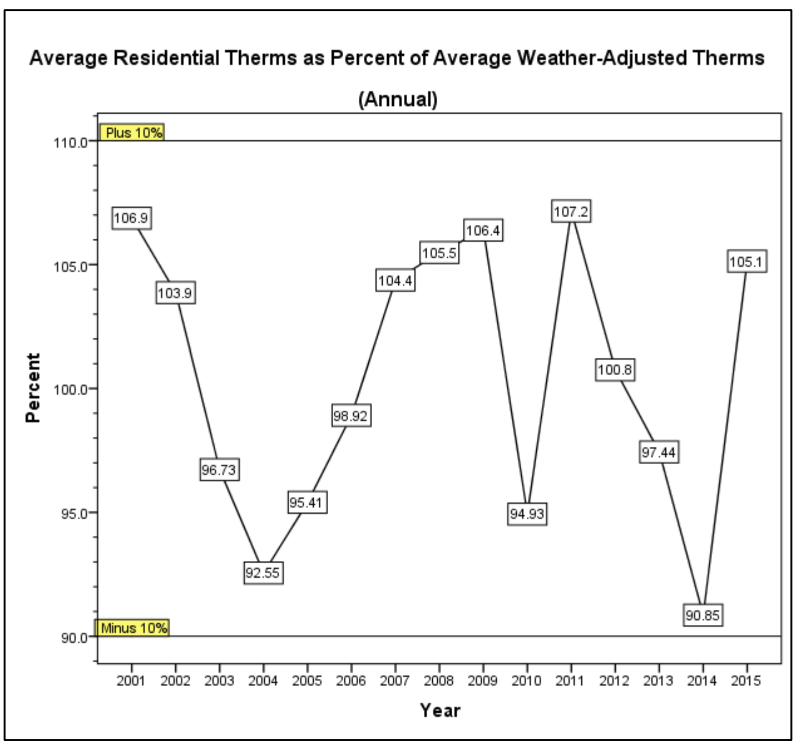


Figure VI.6: The 10% Band for Average Annual Use of Residential Natural Gas (Schedule 23 & 53)

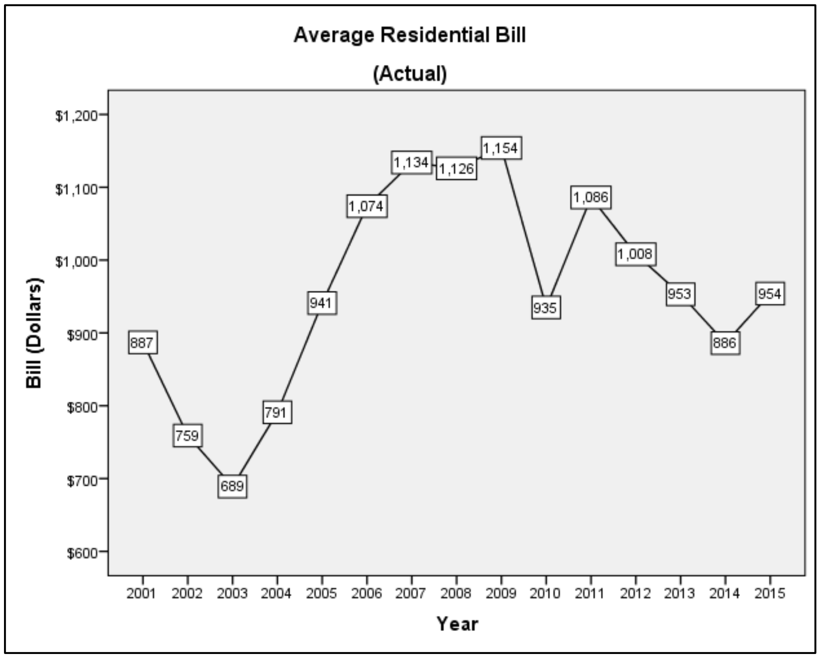


Figure VI.7: Average Annual Bill for Residential Natural Gas (Sch. 23 & 53) – DR 30.29

Figure VI.7 shows the average annual residential bill from 2001 through 2014. There is an initial rise, a tendency towards leveling, and the beginning of a decline. Figure VI.8 shows that average yearly residential cost of natural gas fluctuates with a band of plus and minus 8%.

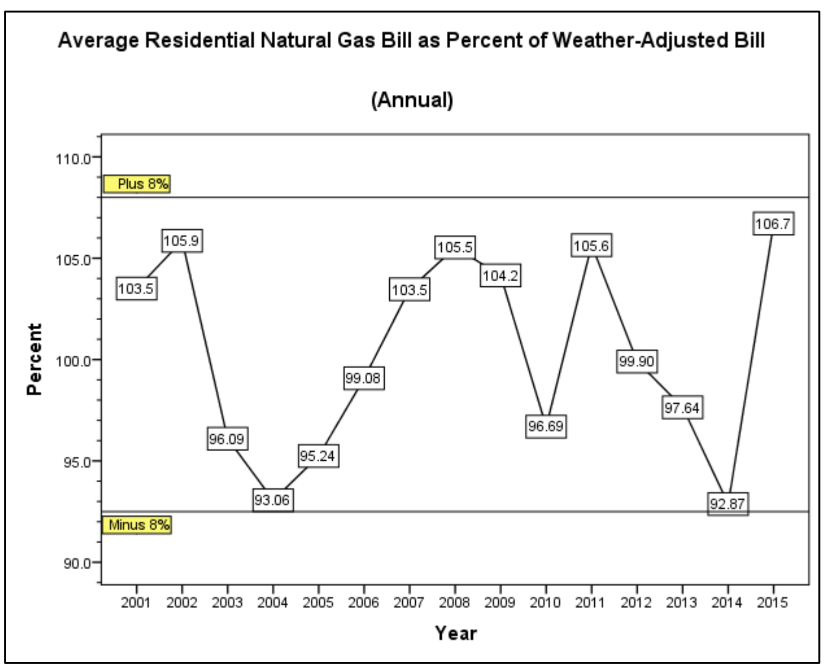


Figure VI.8: The +/- 8% Band for Annual Residential Gas Cost (Sch. 23 & 53) due to Weather – DR 30.29

For electricity, actual average residential kWh usage is shown in Figure VI.9. Average residential usage, if weather had been normal, is shown in Figure VI.10. These two graphs are included to emphasize the relatively small effect of yearly changes in electric energy use compared to the size of energy use in any year. The information in these graphs is shown as an overlay in Figure VI.11 to contrast actual with weather-adjusted energy use.

Figure VI.12 shows that the year-to-year kWh variation as a percentage of weather-adjusted kWh ranges from plus three (3%) percent to minus three percent (-3%).

Figure VI.13 shows how the average household annual bill for electricity has changed since 2001, with an initial rise, a tendency towards leveling, and a beginning of a decline. Figure VI.14 shows the yearly difference in cost as a percentage of weather-adjusted bill. The yearly fluctuation shown in the graph ranges from approximately three percent (3%) on the plus side to approximately minus three percent (-3%) on the minus side.

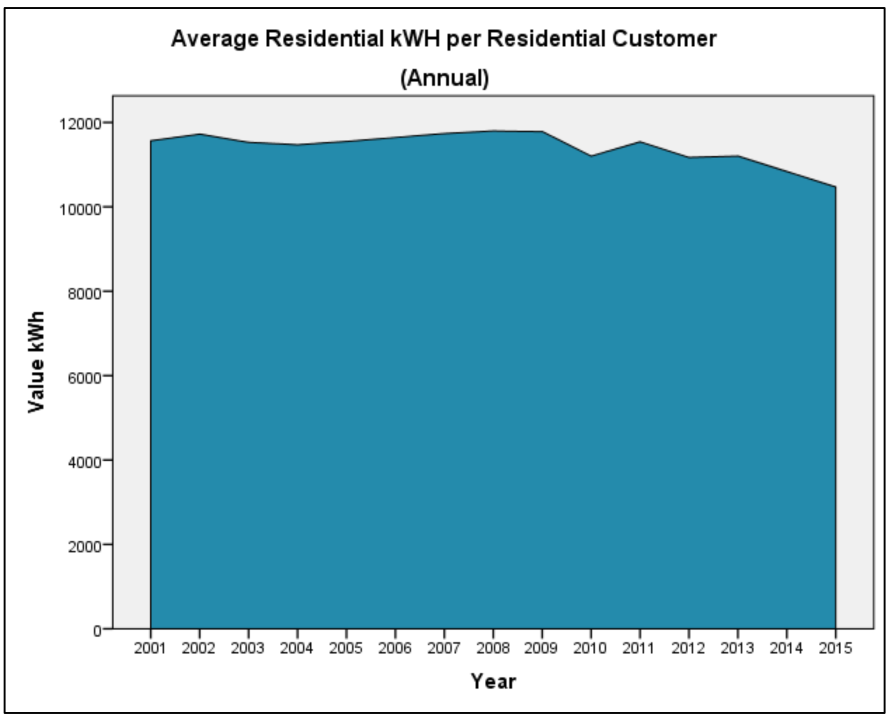


Figure VI.9: Actual Average Residential kWh by Year – DR 30.29

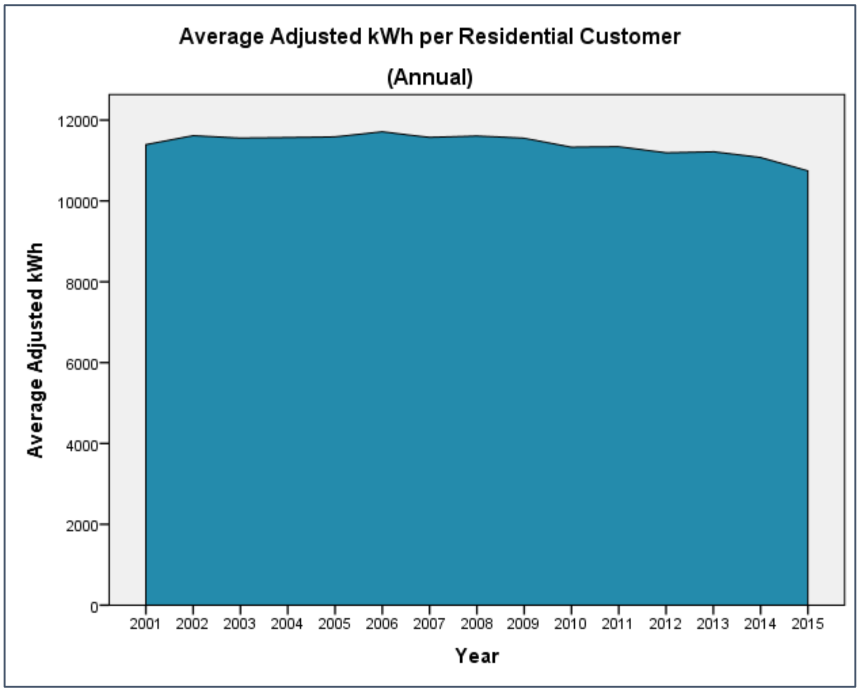


Figure VI.10: Average kWh by Year if Years had been Normal Weather Years – DR 30.29

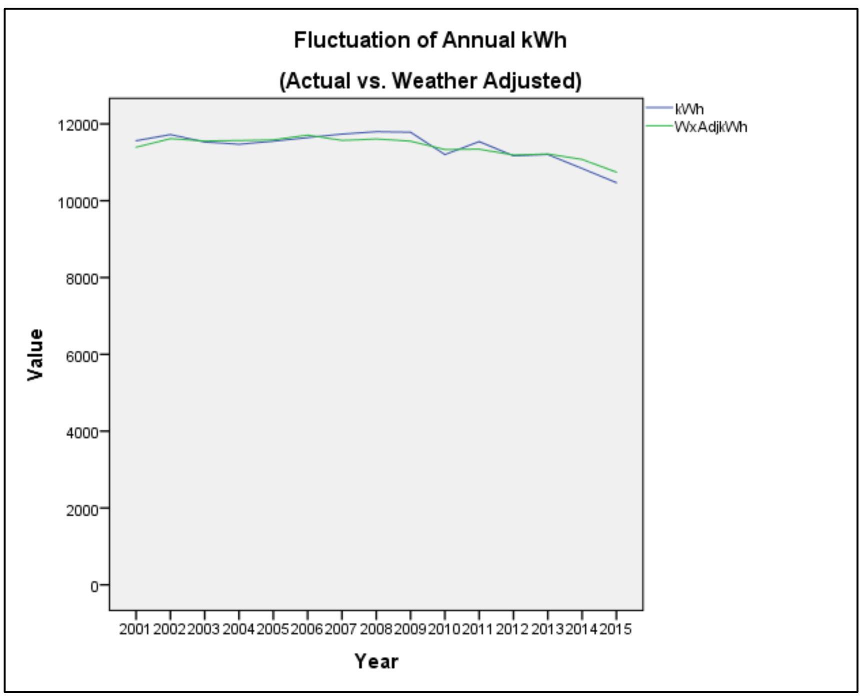


Figure VI.11: Actual vs. Weather Normalized kWh – DR 30.29

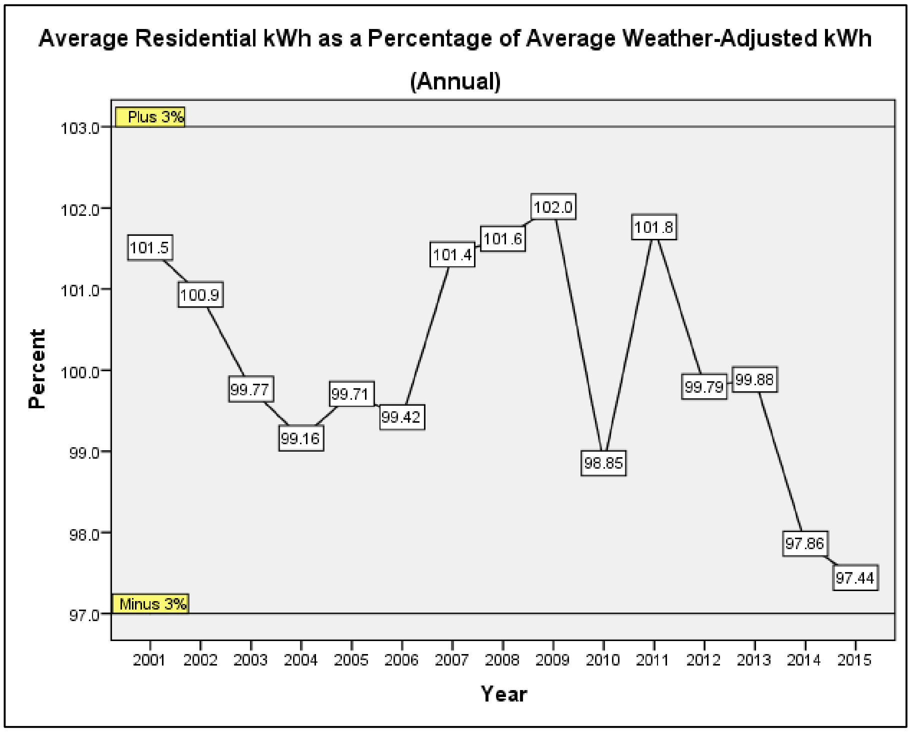


Figure VI.12: The +/- 3% Band for Annual Residential kWh due to Weather – DR 30.29

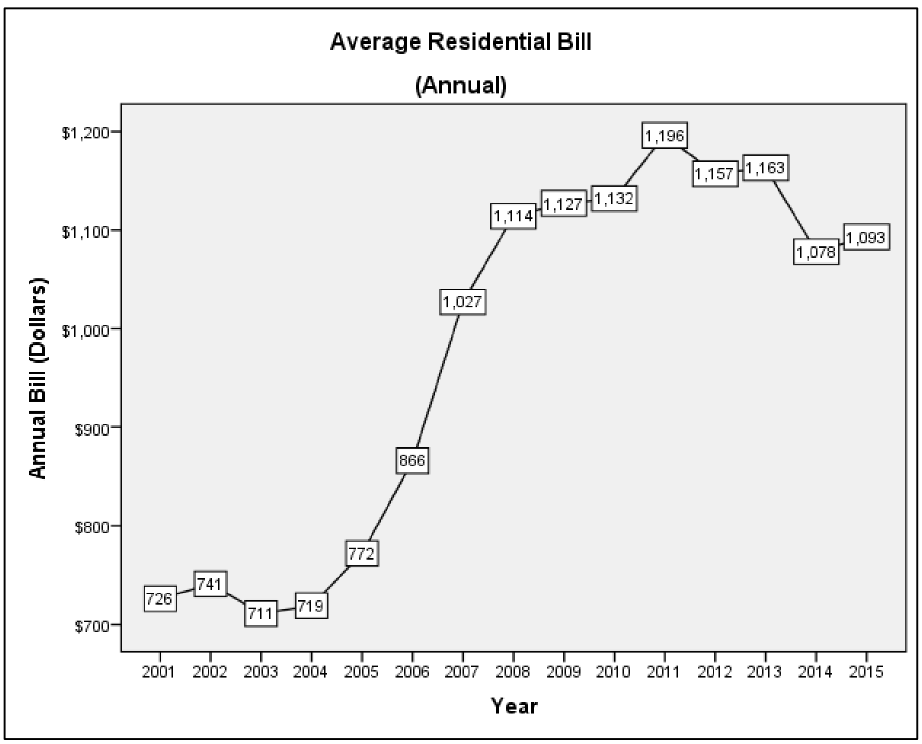


Figure VI.13: Average Residential Electric Bill – DR 30.29

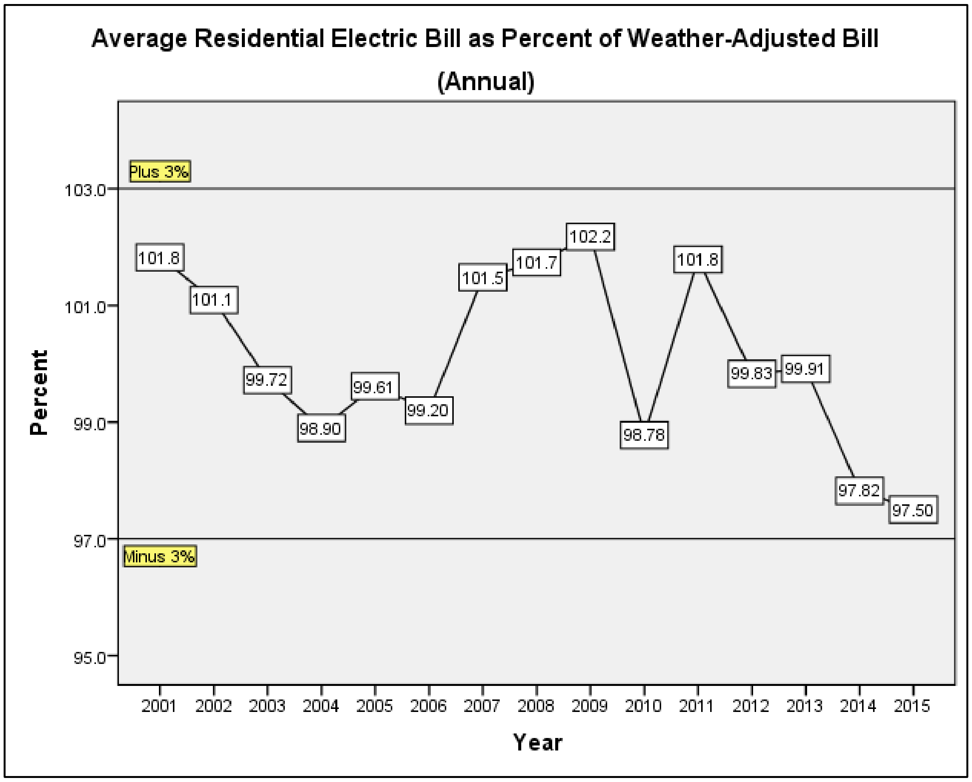


Figure VI.14: The +/-3% Band for Average Annual Residential Electric Bill due to Weather -- DR 30.29

Figure VI.2 through Figure VI.14 provide pictures of the relative size of yearly bill variations to which residential customers are likely to have become accustomed due to weather effects (there is even more variation or "noise" in the data due to month by month seasonal effects). Without including seasonality, changes within the household, or gas cost changes, the band for residential natural gas (Schedules 23 & 53) customers is +/-8%. The band for residential electricity service is +/- 3%. As long as decoupling effects are within these bands, the effects will likely not be discernable by customers from normal variation. *In Section VII, we look more closely at decoupling carryover impacts. These should be understood within the context of the normal range of weather variations.*

As noted, one other factor in cost control is that the commodity cost of gas shows large swings (see Section XII, Figure XII.5 & Figure XII.6).

Cumulative Deferral

Here, we simply note the effect of cumulative deferral caused by the operation of the cap. The cap operates like a pressure relief valve in a mechanical system. If the increase goes above three percent (3%), the value opens and the pressure is released causing the rate (and to a large extent also bills) to be limited. The deferred portion of revenue goes to the following year. There are short sets of years within which the cost of natural gas cycles down or cycles up due to weather cycles. It is not unusual to have two or three similar weather years in a row, making up one side of a cycle (see Section XII). Therefore, deferrals may easily carryover and build across two to three or more years. To deal with this problem, we suggest a simple adjustment by analogy of resetting the pressure relief valve from three percent (3%) to five percent (5%). It is shown in Section VII of this study that this change would have prevented the cumulative deferral problem observed. The future, of course, is an open question. For more on carryover, see Section VII.

Section Summary

The problematic results for four performance indicators for 2015 will need to be watched for 2016 and 2017. There is nothing in the working of the decoupling mechanism that would discourage conservation – conservation remains very much in each customer's interest. We find no adverse impact on cost control or operational efficiency based on data available. The fact that exceeding conservation targets is not an automatic concern of executive management may be considered a positive impact.[72] Plus, PSE's annual average increase in O&M costs has declined when compared to the historical growth rate presented in the decoupling rate plan proceedings under Docket Nos. UE-121697, et al.[73] We establish a kind of "normal" annual weather variation in bills for residential electricity of +/- 3% (Figure VI.13) and for residential natural gas of +/- 8% (Figure VI.8). Due to the cap, overall rate variation is kept at or below 3%.

Cumulative deferral resulting in carryover to more than two years might be considered an adverse effect. For the first three Evaluation Years, *we find no conclusive evidence to suggest that the decoupling mechanism has any adverse effect* that cannot be handled though a simple adjustment analogous to adjusting a pressure relief valve in a mechanical system.[74] Whether cumulative deferral over a short warming cycle is an adverse effect, is a matter of perception. However, we document that it does occur.

[72] A reviewer, in its review of the study of the first Evaluation Year commented that that conservation spending is *not* a measure of success because these costs are passed directly through to the customers via the Schedule 120 tariff rider, and evaluation should take that into consideration. The evaluation team believes that increased conservation spending *is* one of a set of indicators of success and, actually, one of the primary indicators used to contrast the effects of decoupling.

[73] See Response to H. Gil Peach & Associates Data Request No. 30.37.

[74] A reviewer, in reviewing the first Evaluation Year study, requested that the limitation of the finding of no adverse impacts be more explicitly acknowledged. We now have three Evaluation Years of information, so the original conclusion is modified to acknowledge the problem of cumulative increase in deferral.

VII. Review of Deferral Balances

In this section, we review the operation of the decoupling mechanism's impact on deferral balances, deferral amortization and the 3% soft cap on rate changes due to Schedule 142. We also review the impact of weather on use per customer and therefore on deferral rates and balances. We conclude this section with an analysis of the impacts of the component parts of Schedule 142 by rate schedule.

Task Element 6: Examine the Impact of Decoupling on Deferral Balances

This section examines the operation of the decoupling mechanism's impact on deferral balances, deferral amortization and the 3% soft cap. The examination includes the impact of weather on use per customer.

Figure VII.1: Impact of Decoupling on Deferral Balances

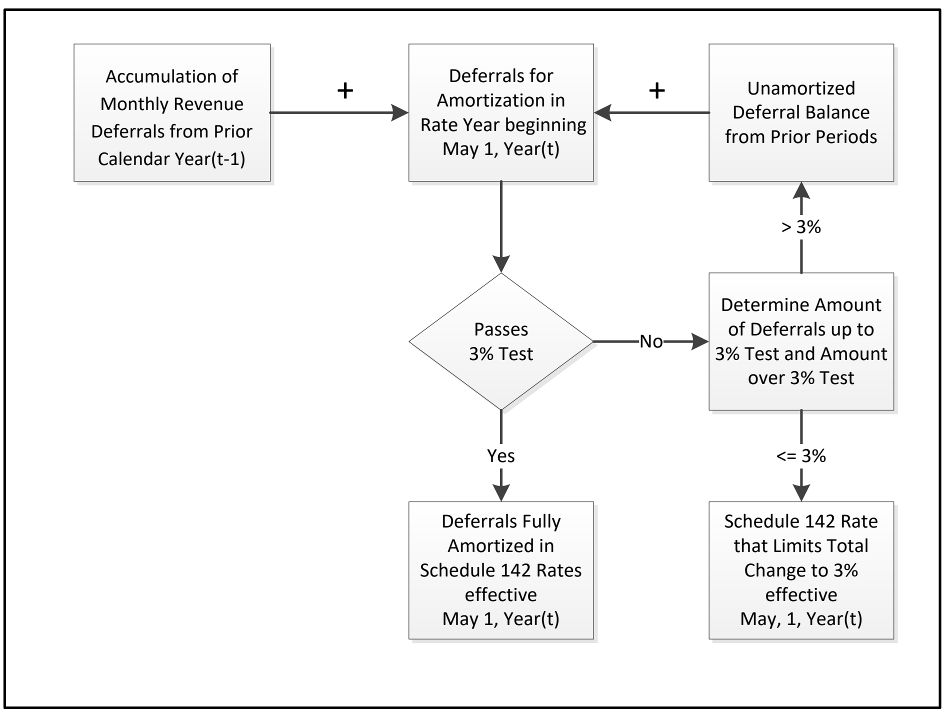


Figure VII.2: Overview of Deferral Accounting and the 3% Test

Figure VII.2 presents a simplified overview of how deferral accounting works in the decoupling mechanism. Each month, the difference between actual delivery revenue and allowed delivery revenue is calculated as deferred revenue. A positive deferral balance means actual revenue has been lower than allowed revenue and vice versa. Cumulative deferred revenue over the course of a calendar year is amortized in Schedule 142 rates, effective the following May 1st. Unamortized deferral balances from previous periods, if any, are added with prior year deferrals before amortization. The resulting Schedule 142 rate, including both the deferral and K-factor components, is then subject to the 3% test which caps the percent change in rates due to Schedule 142 to no more than 3%. If the percent change in rates due to Schedule 142 is not over 3%, the full amount of the deferral balance is amortized in the new Schedule 142 rate. If the 3% cap is reached, deferrals amortized in rates are lowered to 3% and the balance of unamortized deferrals is carried forward to the following rate year where the process repeats.

The three percent rate test is illustrated in the tab titled "3% Test" in Attachments B and C to PSE's Response to H. Gil Peach Data Request No. 30.07. To calculate this test, the prior calendar year weather normalized revenues are first determined for each rate group. Since these revenues include current Schedule 142 revenues, these Schedule 142 revenues are subtracted in order to calculate revenues at levels consistent with those approved in PSE's Expedited Rate Filing ("ERF"). The net revenues (referred to in the file as "Adjusted ERF Normalized Revenues") are then divided by the weather-normalized volumes to derive an average (base) rate. The current Schedule 142 rates are then added to those average base rates. This is used as the baseline (referred to in the file as the "Average Rate Including Schedule 142") upon which the 3% test is conducted. The proposed increase in Schedule 142 rates is then divided by the current baseline rate to determine whether the proposed increase exceeds 3%. If so, the rate increase is limited to 3%, otherwise the full amount of the proposed increase is included the proposed Schedule 142 rates.

Review of Deferral Balances and Impact of Three Percent Cap

Under typical operating conditions, it is reasonable to expect that any deferral balance accumulated from the preceding calendar year would be fully amortized into rates in the new rate year effective May 1st. The Amended Petition for Decoupling Mechanisms states that reaching the 3% soft cap would be an "unlikely event" because delivery revenues only account for about one-third of total revenues.[75] This means that deferral

[75] DOCKETS UE-121697 and UG-121705, AMENDED PETITION FOR DECOUPLING MECHANISMS, Attachment A, p5 and Attachment B, p6.

of delivery revenues would need to be about 9% or more to reach the 3% cap in total rates. The history of the 3% test is shown in Table VII.1.

Table VII.1: Actual Results of 3% Rate Change Test – DR 30.59

	2014 Filing	2015 Filing	2016 Filing
	Rates Effective May 1, 2014	Rates Effective May 1, 2015	Rates Effective May 1, 2016
Electric Decoupling Groups			
Residential	0.1%	2.9%	1.5%
Non-Residential	1.1%	2.4%	-0.1%
Schedules 12 & 26	1.3%	1.7%	1.2%
Schedules 10 & 31	0.7%	5.1%	2.0%
Gas Decoupling Groups			
Residential (Schedules 23 &53)	-1.3%	4.2%	7.3%
Non-Residential	2.4%	0.8%	2.5%
Source: DR 30.59 Attachment A			

As shown in Table VII.1, the 3% test is applied to the four electric decoupling rate groups and the two gas decoupling rate groups with each filing for Schedule 142 rate adjustments. There have been three instances where the 3% cap was exceeded (highlighted in Table VII.1) and deferrals were not fully amortized in Schedule 142 rates. The 3% cap was reached for electric Schedule 31 customers in the 2015 filing. As a result, a portion of deferral balances for Schedule 31 customers were carried forward into the next rate year (2016 filing). Because the 3% test was passed for Schedule 31 customers in the 2016 filing, unamortized deferral balances from prior periods did not persist beyond May 1, 2016 for this group of customers.

Residential gas customers (Schedules 23 & 53) also reached the 3% cap on rates in the 2015 filing but, unlike electric Schedule 31 customers, residential gas customers reached the 3% cap again with the 2016 filing. This means that deferred revenue balances were carried forward in both filings. Table VII.2 shows the magnitude of these deferral balances for both electric Schedule 31 and gas residential rate groups when the 3% test impacts treatment of deferrals.

Table VII.2: Deferred Revenue for Gas and Electric Customer Groups Impacted by 3% Cap – DR 30.42

Line No.		2015 Filing Rates Effective May 1, 2015	2016 Filing Rates Effective May 1, 2016	
	Electric Schedule 10 & 31			
1	Estimated Amortization Balance as of April 30 of filing year	$ (7,166)	$ 1,126	
2	Deferred Balance at End of last CY	$ 1,856,220	$ 1,883,997	(1)
3	Interest Balance at End of last CY	$ 20,522	$ 80,218	
4	Earnings Test Adjustment	$ -	$ (508,095)	
5	Total Deferred Revenues to Amortize	$ 1,869,576	$ 1,457,245	
6	Amount of Line 1 to Amortize Post 3% Rate Test	$ -	$ 1,457,245	
7	Deferred Revenues Not Amortized due to Rate Test	$ 1,869,576	$ -	
	Gas Residential (Schedules 23 & 53)			
8	Estimated Amortization Balance as of April 30 of filing year	$ (856,350)	$ 1,275,520	
9	Deferred Balance at End of last CY	$ 22,137,962	$ 53,970,360	(2)
10	Interest Balance at End of last CY	$ 67,481	$ 1,592,833	
11	Earnings Test Adjustment	$ (938,416)	$ (4,062,386)	
12	Total Deferred Revenues to Amortize	$ 20,410,676	$ 52,776,327	
13	Amount of Line 4 to Amortize Post 3% Rate Test	$ 12,204,208	$ 24,039,360	
14	Deferred Revenues Not Amortized due to Rate Test	$ 8,206,468	$ 28,736,968	

(1) 2016 Filing includes $1.9M not amortized in 2015 Filing

(2) 2016 Filing includes $8.2M not amortized in 2015 Filing

Source: DR 30.42 Attachment A (>3% Test Summary)

Total deferred revenue to amortize is the sum of the estimated amortization balance, the deferral balance from last calendar year with interest and shared earnings. Deferred revenues from the prior year filing not amortized due to the rate test are included in the deferral balance from last calendar year. The potential for increasing deferral balances associated with consecutive Schedule 142 filings impacted by the 3% cap is shown in Table VII.2. First, consider electric Schedule 31, which accumulated $1.87 million for amortization. The entire balance was carried forward to the 2016 filing. However, because the 3% cap was not reached in the 2016 filing all deferred revenue for amortization was amortized in Schedule 142 rates. Hence, no electric Schedule 31 deferrals from the 2016 filing were carried forward for the 2017 filing.

Explanation of 5.1% Unconstrained Increase for Schedule 31 for Rates Effective May 2015

Electric Schedules 10 & 31 reached the 3% rate test limit with an unconstrained increase calculated to be 5.07%.[76] The primary reason that this unconstrained rate increase was so high (relative to the other years within the three-year evaluation period of this study) is the significant deferral that accrued in the prior calendar year. As shown in line 2 of Table VII.2, these schedules accrued almost $1.9 million in deferred revenue in calendar year 2014. This is relative to under $28 million in allowed test year delivery revenue (shown in line 2 of the same tab of the "Rate Change Calc 10,12, 26, 31" tab of Data Request 20.07, Attachment B.

The primary contributor to this deferred revenue can be traced to the difference between the expected kW demand in 2014 and the amounts actually experienced. The rates calculated to go into effect for this rate group assumed 3.47 million kW in billing determinants for the 12 months beginning May 1, 2014 (see the line 24 in the tab titled "Rate Change Calc 26&31" in Attachment G to PSE's Response to H. Gil Peach & Associates Data Request No. 1.05). Ultimately (as shown in lines 5 and 9 of the tab titled "Elec Sch 31 Deferral Calc 2014" in Attachment B to PSE's Response to H. Gil Peach Data Request No. 20.07), this rate group only had slightly less than 3.2 million kW, roughly a 10% decrease.

Other factors that contributed to the high level of deferrals in 2014 include: (a) the inherent upward pressure put on deferrals by the annual rate plan increases to allowed delivery revenue per customer, (b) the lag between the time the rate plan increases were applied to allowed revenue per customer (January 1, 2014) and when the volumetric Schedule 142 rates went into effect that reflected the rate plan increases (May 1, 2014) and (c) the fact that Schedules 10 & 31 had a rate decrease under Schedule 142 during calendar year 2014 that absorbed a portion of the capacity to recover higher future costs (as illustrated in lines 35-39 in the tab titled "Elec Sch 31 Deferral Calc 2014" in Attachment B of PSE's Response to H. Gil Peach & Associates Data Request No. 20.07).

The gas residential rate group is the other group that experienced unamortized deferrals due to the 3% cap. For this group, we see from Table VII.2 that consecutive application of the 3% cap in both the 2015 filing and the 2016 filing resulted in increased levels of deferred revenue carried into the next Schedule 142 filing. In the 2015 filing, $12.2 million was amortized in rates effective May 1, 2015 and $8.2 million was carried forward

[76] Attachment B of PSE's Response to H. Gil Peach & Associates Data Request No. 20.07 for rates effective May 1, 2015.

into the 2016 filing, with interest. With the 2016 filing, $24 million was amortized in rates effective May 1, 2016. Despite this being nearly twice the level amortized in rates the preceding rate year ($12.2 million), unamortized deferrals carried forward into the next filing (2017) rose to $28.7 million.

Explanation of Application of the Earnings Test

The earnings test is illustrated in the tab titled "Electric Earn Test" in Attachment B to PSE's Response to H. Gil Peach & Associates Data Request No. 30.07 and the tab titled "Gas Earn Test" in Attachment C to PSE's Response to H. Gil Peach & Associates Data Request No. 30.07. To calculate this test, PSE's restated rate base (as reported in its Commission Basis Report (CBR) for the prior calendar year) is first multiplied by its authorized rate of return (currently 7.77%) to determine the "Maximum Net Operating Income." This maximum amount is compared to the restated net operating income ("NOI") from the CBR in the prior calendar year. If the restated NOI exceeds the maximum allowed NOI, 50 percent of the difference between the restated and maximum NOI is returned to customers. This amount is grossed up by PSE's "gross conversion factor" that accounts for PSE's federal income taxes and adjustment for revenue sensitive items (primarily state utility tax).

In 2015, PSE exceeded its allowed revenue by approximately $14.8 million for electric service and $6.8 million for gas service. After sharing and gross ups, the amount shared with customers in rates effective May 1, 2016 were approximately $11.9 million for electric service and $5.5 million for gas service. Again, these calculations are reflected on the above-mentioned tabs in Attachments B and C to PSE's Response to H. Gil Peach & Associates Data Request No. 30.07.

The $11.9 million in electric revenue and $5.5 million in gas revenue is then allocated across electric and gas decoupling rate groups in proportion to their relative share of margin revenue (i.e., allowed revenue per customer multiplied by the number of customers served) in the prior calendar year (i.e., the period in which the over-earning occurred). These calculations are presented in the tab titled "Earnings Test Allocation" in Attachments B and C of PSE's Response to H. Gil Peach & Associates Data Request No. 30.07.

The allocated amount of shared revenue is then applied against the allowed delivery revenue that would otherwise be recovered in the rate year. For example, recoverable delivery revenue from residential electric customers in rates effective May 1, 2016 was approximately $7.2 million lower as a result of the allocated over-earnings for 2015. This is slightly less than 2% of the approximately $372 million in Test Year Allowed Delivery Revenue shown in line 2 of the rate calculations. These calculations are shown in the line titled “2015 Earnings Test Adjustment” in the rate change calculation sheets in Attachments B and C of PSE’s Response to H. Gil Peach & Associates Data Request No. 30.07.

Most of the impact of the earnings test to date was experienced for rates effective May 1, 2016. A small amount of over-earnings was also experienced for gas service in rates effective May 1, 2015. The amount shared with gas residential customers, for example, was slightly less than $1 million. These calculations are presented in Attachment C to PSE’s Response to H. Gil Peach & Associates Data Request No. 20.07.

Impacts of Accumulating Deferral Balances

We turn now to a consideration of some of the issues associated with accumulating deferral balances. Our comments are focused on the gas residential rate group but apply to any rate group impacted by consecutive years in which the 3% cap applies. Although it has only been a single rate group in which the 3% cap was a factor in two consecutive years, the growth in unamortized deferral balances for gas residential customers is cause for investigation and ongoing monitoring. We will review explanations for the growing deferral balance later in this section but the primary driver is simply warmer-than-normal weather. There is no guarantee that weather will return to normal in the near term and if the warm weather experienced in the last few years persists, then unamortized balances in the gas residential rate group can be expected to grow.[77]

The possibility of growing and persistent deferral balances was recognized and referred to by Washington Utilities and Transportation Commission (WUTC) staff as “Snowballing Deferral Balance”.[78] Such a situation creates two issues; a growing “debt” owed by residential gas customers and untimely collection of revenue by PSE. A growing gas debt burden represented by accumulating deferral balances continues to put upward pressure on rates with each new rate year. Perhaps a larger concern for residential customers is what happens in the event of a significantly colder than normal year. When that happens, customers experience significantly higher bills not only from the cost of energy in the current period but also from the accelerated payback of the debt owed in

[77] We do expect short warming cycles and short cooling cycles (each of one to four or sometimes seven years) to balance. This might require waiting from one to seven years. Though Washington’s climate is warming, the climate warming trend is small for this study compared with cyclical weather changes. Although, in principle, normal weather should be redefined to take climate trend into account, it is not necessary to do so for this study due to its three-year analysis window (see Reference Appendix III for discussion of weather effects).

[78] Staff memo, Chris McGuire, Energy Policy Analyst, Washington Utilities and Transportation Commission, UE-160367 and UG-160368, April 28, 2016.

the form of amortized deferrals from prior periods. Of course, the deferral balance would be retired much more quickly with colder than normal weather but it also places a heavier financial burden on customers.

A development exists that also might be viewed as having adverse impact on PSE through prolonged recovery of deferred revenue. PSE believes that, to be consistent with Generally Accepted Accounting Practice, deferred decoupling revenue should be collected within two years of the period it was recognized.[79] The application of the rate test at the 3% level is currently not expected to achieve that objective, particularly for Gas Residential customers (Schedules 23 & 53). PSE estimates that the $28.7 million of unamortized revenue due to the Rate Test (see last line of Table VII.2) will not be fully recovered until April of 2018.[80]

One possible remedy for the issues created for customers and PSE from carrying deferral balances is to adjust the level of the Rate Test so that more, if not all, deferred revenue is amortized into rates. PSE has run simulations and determined that a Rate Test of 4.8% would have resulted in full amortization of deferred revenue.[81] In our opinion, the WUTC should consider raising the level of the Rate Test to 5% to reduce the possible adverse impacts of growing deferral balances on customers and PSE.

Trends in Use per Customer and Other Factors Impacting Deferral Balances

It is important to understand trending use per customer because of the impact use per customer has on deferred revenues. A change in monthly use per customer from the level experienced in the ERF Test Year (July 2011 - June 2012) translates to a change in monthly deferrals in the opposite direction, if all other things are equal. Lower use per customer in a Rate Group, for example, translates to higher revenue deferrals, again, all things being equal. It is important to note that this would not be the case if PSE accurately projects the level of use per customer in the applicable rate year of each Schedule 142 filing.

[79] PSE response to H. GIL PEACH & ASSOCIATES Data Request No. DR 30.42. Note, however, that GAAP principles are inherently in tension with each other. The two-year rule involves one principle that keeps revenue recovery timely; keeping incurred revenue together with eventually realized revenue across years is another. When the inherent tension among GAAP principles is activated in a practical situation, there is an ethical requirement to make a choice and provide documentation. While GAAP is formally flexible in this way, a company may select to follow a traditional practice.

[80] PSE response to H. GIL PEACH & ASSOCIATES Data Request No. DR 30.42.

[81] PSE response to H. GIL PEACH & ASSOCIATES Data Request No. DR 30.59.

For residential customers, and to a lesser extent commercial customers, weather is a dominant factor when it comes to understanding changes in use per customer. This is especially true for gas residential customers where space heating accounts for a large portion of total energy use. This section begins with an examination of weather patterns over the last three evaluation years to add context to the review of use per customer that follows.

Actual Compared to Normal Weather

Figure VII.3 shows the difference between actual and normal heating degree days (HDD) from January 2013 through September 2016. A negative value means warmer than normal weather (*i.e.,* actual HDDs were less than normal).

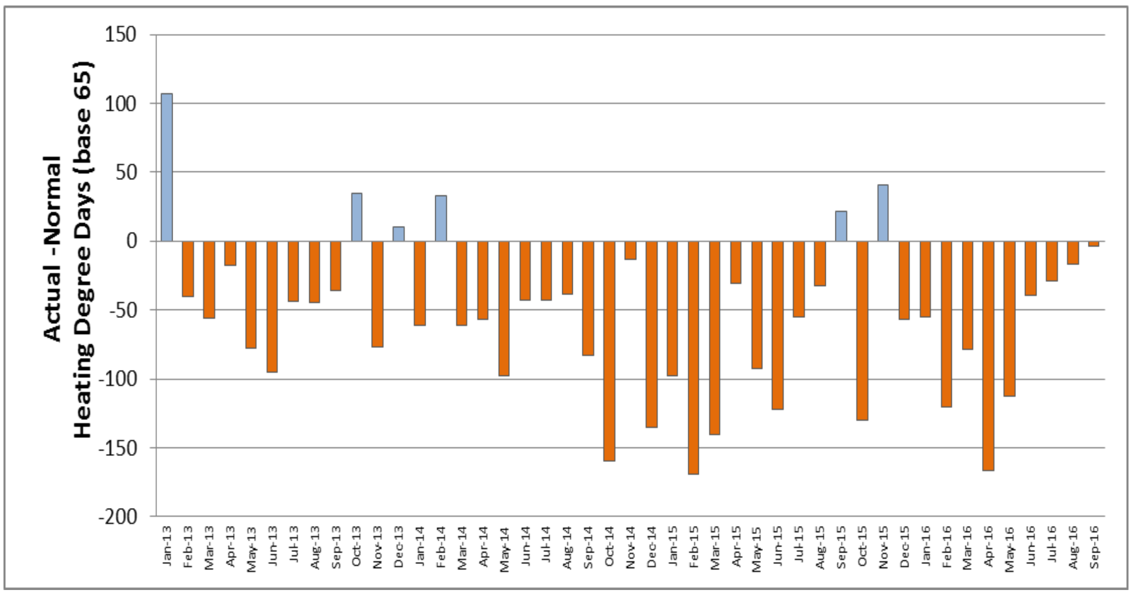


Figure VII.3: Difference between Actual and Normal Monthly Heating Degree Days (HDD), PSE – DR 30.62

Actual weather has been colder than normal in only 6 months of the 45 months of history shown in Figure VII.3. The monthly data show a consistent and prolonged pattern of warmer than normal weather but it is difficult to see the magnitude of the weather variance from normal. Table VII.3 shows actual HDD and normal HDD after annualizing the monthly data to show the last three evaluation years.

Table VII.3: Actual vs. Normal Heating Degree Days – DR 30.62

	12 Months Ending		
	Jun-14	Jun-15	Jun-16
Actual	4,471	3,771	4,072
Normal	4,915	4,895	4,856
Percent Difference	-9%	-23%	-16%
Source: DR 30.62			

Actual HDD have been lower than normal HDD in each of the last three evaluation years. The difference as a percent of normal has ranged from -9% in the year ending June 2014 to -23% in the year ending June 2015. For Evaluation Year 3, ending in June 2016, actual HDD were 16% lower than normal. This pattern of warmer weather over the first three evaluation years is useful for understanding historical use per customer over the same periods.

Since a short warming cycle had the largest impact on the one decoupling group that shows cumulating deferral, it is tempting to see if the weather trend or weather cycles could or should be incorporated into the decoupling design. So far, the problem of cumulating deferrals has occurred for only one decoupling group: Residential natural gas (Schedules 23 & 53), for which the major variation since 2001 has been extreme changes both up and down in commodity cost, followed by moderate changes due to short weather cycles of warming and cooling. The climate-warming trend does not have to be considered. Though leading to a very different world over a 100 to 140 years, the slope of the trend line is much too small in size over a five-year period to warrant taking the trend into account (see the *Weather Appendix* in *Section XII*). However, changing how weather or background factors such as the commodity cost of natural gas are included in a decoupling calculation cannot change the required revenue requirement. The only thing that could be affected by modifying the approach is the allocation of costs across years.

It would be productive to include a weather person/climate adjustment person within the planning group; someone who understands how weather cycles and climate adjustment work could alert the planning group to likely cumulative deferral patterns and how long they might be expect to run.

Annual Use per Customer

Use per customer (UPC) by electric and gas rate schedules is shown in Table VII.4 for the ERF Test Year (July 2011 – June 2012) and each of the first three evaluation years. The evaluation years are repeated in two sections, actual UPC expressed as the percent difference from the ERF Test Year and weather normalized UPC, also as a percentage difference from the ERF Test Year.

Table VII.4: Annual Use per Customer compared to ERF Test Year – DR 30.62

	ERF Test Year UPC	Actual Use per Customer			Normalized Use per Customer		
		Percent Difference from ERF			Percent Difference from ERF		
	July 2011 - June 2012	July 2013 - June 2014	July 2014 - June 2015	July 2015 - June 2016	July 2013 - June 2014	July 2014 - June 2015	July 2015 - June 2016
A	B	C	D	E	F	G	H
--------- Electric ---------							
Residential Group:	kWh						
Schedule 7	11,220	-1.2%	-7.1%	-6.4%	-0.2%	-4.2%	-3.8%
Non-Residential Group:							
Schedules 8 & 24	23,085	0.9%	0.5%	1.8%	0.8%	0.9%	2.5%
Schedules 11 & 25	406,765	0.9%	-0.6%	-1.4%	0.7%	-0.7%	-1.3%
Schedule 29	22,415	4.9%	24.6%	18.8%	4.1%	21.9%	16.4%
Schedule 35	4,067,400	10.5%	31.0%	18.2%	10.5%	31.0%	18.2%
Schedule 40	6,314,895	-15.5%	-20.0%	-22.5%	-15.7%	-20.1%	-22.5%
Schedule 43	795,123	-0.2%	-11.4%	-7.9%	1.4%	-6.9%	-4.5%
Schedule 46 & 49	30,449,562	-16.2%	-13.6%	-18.1%	-16.2%	-13.6%	-18.1%
Schedule 12 & 26 Group:	KW						
Schedules 12 & 26	5,839		0.9%	1.0%	NA	NA	NA
Schedule 10 & 31 Group:							
Schedules 10 & 31	6,722		0.2%	2.0%	NA	NA	NA
--------- Gas ----------							
Residential Group:	Therms						
Schedules 23 & 53	795	-1.0%	-18.4%	-12.4%	4.0%	-3.9%	-2.3%
Non-Residential Group:							
Schedule 31	3,752	2.5%	-12.2%	-5.7%	6.6%	-0.8%	2.2%
Schedule 31T							
Schedule 41	40,184	25.2%	11.1%	16.8%	27.3%	19.1%	22.2%
Schedule 41T	176,110	-0.6%	-2.6%	0.8%	-0.2%	-0.3%	2.6%
Schedule 86	40,232	-10.0%	-22.1%	-12.9%	-4.2%	-6.1%	-2.4%
Schedule 86T	26,572	225.5%	288.5%	338.2%	225.5%	288.5%	338.2%
Source: DR 30.62							

Table VII.4 presents a great deal of information (in summary form) useful for determining changes in UPC from the Test Year and how much of that change is likely due to weather. The first section of the table (columns C, D and E) is useful for seeing how much and in which direction UPC has changed since the Test Year. The second section (Columns F, G and H) is useful for seeing how much of the change in actual UPC was likely due to weather. A change in actual UPC (columns C, D and E) with a similar pattern as the drop in HDD shown in Table VII.3 is indicative of a weather sensitive customer group. Something other than weather could coincidently be causing a weather-like pattern in actual UPC, although the evidence of weather sensitively is much greater when weather normalization (Columns F, G and H) removes or greatly reduces the pattern in actual UPC.

Only two electric rate schedules, Schedule 7 (residential group) and Schedule 43 (non-residential group), appear to be somewhat weather sensitive. Actual UPC in both groups follow a pattern of warmer than normal weather and much of that pattern is removed by normalization. Three gas rate schedules, Schedule 23 (residential group), Schedule 31 (non-residential group) and Schedule 86 (non-residential group) also appear to be weather sensitive. These weather sensitive electric and gas rate schedules are more susceptible to relatively larger accruals of revenue deferrals from consecutively colder or warmer than normal weather. In the case of warmer than normal weather, accrual balances contribute to the possibility of reaching the 3% Rate Cap for weather sensitive rate schedules.

Some rate schedules have experienced large changes in UPC since the Test Year; these changes appear unrelated to weather. UPC in both electric Schedule 29 and Schedule 35 has been significantly higher than the Test Year. Higher UPC in these schedules would, all other things being equal, contribute to higher UPC for the Electric Non-Residential Rate Group as a whole. The reverse is true for electric Schedule 40 and Schedule 46 and 49. UPC has dropped for these rate schedules, working to offset increases elsewhere in the Non-Residential Rate Group. Two gas schedules from the Non-Residential Group have experienced large non-weather related increases in UPC: Schedules 41 and 86T.

Large changes in UPC within a rate schedule can be caused by disproportionate growth in customers on one end or the other of the UPC distribution for that schedule, by large customers changing rate schedules and by large energy efficiency projects. Many of these changes within rate groups offset between schedules. Since deferrals are calculated at the Rate Group level, the variation in UPC from the Test Year is minimized by offsetting changes at the rate schedule level.

It should also be noted that the electric residential and gas residential rate groups' UPC remains lower than the Test Year UPC even after adjusting for weather. For electric residential customers in the last two evaluation years, normalized UPC was about 4% lower than the Test Year. For gas residential customers, normalized UPC was about 4% lower than normal in the year ending June 2015 and 2% lower than normal in the year ending June 2016. This is only two years of results; even if UPC has shifted or is trending lower for electric or gas residential customers, these kinds of gradual changes should be able to be accommodated within the 3% Rate Test. It is the large changes in use per customer that can trigger the 3% Rate Test. In such cases, unamortized deferral balances may become an issue unless the change is temporary.

Attribution of Schedule 142 Impacts by Rate Schedule

Schedule 142 rate impacts reflect a number of things besides the amortization of decoupling deferrals, which is traditionally the only rate impact of decoupling. Included in the Schedule 142 rate impacts is the planned escalation of allowed delivery revenue (K-factor) and balances in deferral and amortization accounts due to some unique features of PSE's decoupling mechanism. Variances from projected use per customer (which PSE forecasts in the annual rate filings to set rates) are also picked up in the decoupling deferrals, as is the lag between when K-factor increases go into effect on Jan 1st and when new Schedule 142 rates take effect on May 1st. It is important to note that these unique features do not impact the total revenue PSE will receive but only impact the timing of when PSE will receive these revenues. To accurately illustrate the impacts from decoupling and the K-factor increases on rates and revenues, it is important to break out the total Schedule 142 impact into multiple components to include a component that tracks the impact of PSE's forecast methodology and the lag in rates mentioned above. To accomplish this breakout, it is necessary to recalculate the Schedule 142 filings in such a way as to isolate the impact of each single component from the others. Results from this simulation are shown in Table VII.5 for electric rate schedules and Table VII.6 for gas rate schedules.[82]

These tables show the Total Rate impact broken out by Deferral Amortization, Forecast and Other components and K-factor for both the 2015 Filing (effective May 1, 2015) and 2016 Filing (effective May 1, 2016). The Total Decoupling impact on rates is also shown as the sum of the Deferral and Forecast and Other components. The Total Rate column is the sum of the Total Decoupling and K-factor columns. As the name implies, the Total Rate column shows the revenue from a change in the Schedule 142 rate, expressed as a percentage of projected rate year revenue calculated at current rates (rates prior to the effective date of the proposed Schedule 142 rate change). These percentage numbers are not changed by the simulation effort to break out the component parts. Deferral Amortization & K-factor impacts represent impacts excluding the forecasted Schedule 142 rate methodology. In other words, these two components are calculated by relying on Test Year assumptions rather than forecast year assumptions. Deferral Amortization impacts also don't include deferrals due to the lag between when K-factor increases go into effect on January 1st and when rates take effect on May 1st. The "Forecast & Other" column picks up impacts associated with the forecast methodology, lag between K-factor increases and when rates go into effect, and 3% Rate Test, where applicable.

We see in Table VII.5 that the Total Rate impact on electric rate schedules ranged mostly between 2% and 3% in 2015 and 0% to 2% in 2016. Deferral Amortization

[82] The results of this simulation are provided by PSE in response to DR 30.66

(calculated as described above) shows the estimated impact of the decoupling mechanism after accounting for the K-factor and removing the forecast methodology. After isolating the Deferral Amortization in this manner, we see that it ranges from 0% to 2% in the 2015 Filing and is mostly between -1% and 0% in the 2016 Filing. Barring a permanent shift in use per customer from the Test Year, this is the expected pattern after isolating the decoupling impact. In some years, revenue deferrals are positive and in some years they are negative, which causes Deferral Amortization to take on the same pattern. When taken together, the Deferral Amortization and Forecast and Other make up the Total Decoupling Impact.

Table VII.5 shows that the K-factor ranges around 1% for most rate schedules. By definition, the allowed volumetric delivery revenue per customer increases by the K-factor (3% for electric customers) annually. Since delivery revenue accounts for about a third of total revenue, a 3% increase in delivery expenses translates to a K-factor impact on revenue of around 1%. The variation around 1%, is consistent between filings and reflects the mix of delivery and power related costs for different rate schedules. The Forecast and Other component ranges from about 0% to 2.5% in the 2015 Filing and -1% to 0% in the 2016 Filing.

We see in Table VII.6 that the Total Rate impact on gas rate schedules ranged between 0.4% and 2.9% in 2015 and roughly 2% to 5% in 2016. Deferral Amortization (calculated as described above) shows the estimated impact of the decoupling mechanism after accounting for the K-factor and removing the forecast methodology. After isolating the Deferral Amortization in this manner, we see that it ranges from 1.2% to 4.7% in the 2015 Filing and between 1% and 3% in the 2016 Filing. For residential customers, the Deferral Amortization component is about 2% in both filings, due mainly to significantly warmer than normal weather driving use per customer lower than the Test Year. The positive values for the Deferral Amortization component in both Filings show variance from Test Year assumptions in both cases. This table shows the K-factor ranging around 1% for most rate schedules and increasing between the 2015 Filing and the 2016 Filing. By definition, the allowed volumetric delivery revenue per customer increases by the K-factor (2.2% for gas customers) annually. Delivery revenue as a percentage of total revenue has been increasing in recent years with the drop in the commodity cost of gas and is now about 50%. Since delivery revenue now accounts for about half of total revenue, a 2.2% increase in delivery expenses translates to a K-factor impact on revenue of around 1.1%. The variation around 1.1% is consistent between filings and reflects the mix of delivery and energy related costs for different rate schedules. The Forecast and Other component ranges from -4.6% to 0% in the 2015 Filing and 0% to 0.2% in the 2016 Filing.

Table VII.5: Attribution of Schedule 142 Impacts by Electric Rate Schedule – DR 30.66

	May 1, 2015						May 1, 2016					
		A	B	C=A+B	D	E=C+D		A	B	C=A+B	D	E=C+D
Customer Class	Rate Schedule	Deferral Amortization	Forecast & Other	Total Decoupling	K-Factor	Total Rate	Rate Schedule	Deferral Amortization	Forecast & Other	Total Decoupling	K-Factor	Total Rate
Residential	7/7A	1.92%	-0.10%	1.82%	1.03%	2.85%	7/7A	0.15%	0.33%	0.48%	1.05%	1.53%
Secondary Gen Svc - Small	8 & 24	0.81%	0.53%	1.34%	0.81%	2.15%	8 & 24	-0.18%	-0.77%	-0.95%	0.83%	-0.12%
Secondary Gen Svc - Medium	11 & 25	0.88%	0.57%	1.44%	0.88%	2.32%	11 & 25	-0.19%	-0.83%	-1.02%	0.89%	-0.13%
Secondary Gen Svc - Large	12 & 26	-0.09%	1.03%	0.94%	0.72%	1.66%	12 & 26	-0.61%	1.12%	0.50%	0.70%	1.20%
Secondary Irrigation Svc	29	0.97%	0.63%	1.60%	0.97%	2.57%	29	-0.22%	-0.96%	-1.19%	1.04%	-0.15%
Total Secondary Voltage		0.63%	0.66%	1.29%	0.82%	2.11%		-0.28%	-0.39%	-0.66%	0.82%	0.16%
General Service	10 & 31	-0.37%	2.53%	2.16%	0.84%	3.00%	10 & 31	-0.73%	1.93%	1.20%	0.79%	1.99%
Seasonal Irrigation & Drainage Pumping	35	1.60%	1.04%	2.65%	1.60%	4.25%	35	-0.31%	-1.33%	-1.64%	1.43%	-0.21%
Interruptible Total Electric Schools	43	0.89%	0.58%	1.47%	0.89%	2.36%	43	-0.19%	-0.83%	-1.02%	0.89%	-0.13%
Total Primary Voltage		-0.26%	2.35%	2.09%	0.85%	2.94%		-0.68%	1.68%	1.00%	0.80%	1.80%
Campus Rate	40	1.13%	0.73%	1.86%	1.12%	2.98%	40	-0.25%	-1.06%	-1.31%	1.14%	-0.17%
Interruptible	46	1.01%	0.66%	1.68%	1.01%	2.69%	46	-0.25%	-1.10%	-1.35%	1.18%	-0.17%
General Service	49	1.24%	0.80%	2.05%	1.24%	3.29%	49	-0.29%	-1.24%	-1.53%	1.33%	-0.20%
Total High Voltage		1.23%	0.79%	2.02%	1.22%	3.24%		-0.28%	-1.22%	-1.51%	1.32%	-0.19%

Table VII.6: Attribution of Schedule 142 Impacts by Natural Gas Rate Schedule – DR 30.66

	May 1, 2015						May 1, 2016					
		A	B	C=A+B	D	E=C+D		A	B	C=A+B	D	E=C+D
Customer Class	Rate Schedule	Deferral Amortization	Forecast & Other	Total Decoupling	K-Factor	Total Rate	Rate Schedule	Deferral Amortization	Forecast & Other	Total Decoupling	K-Factor	Total Rate
Residential	23/53	1.86%	-0.03%	1.83%	1.07%	2.90%	23/53	2.04%	-0.04%	2.00%	1.23%	3.23%
Commercial & Industrial	31	1.76%	-1.74%	0.02%	0.67%	0.69%	31	1.34%	0.11%	1.45%	0.72%	2.17%
Commercial & Industrial - Transportation	31T	NA	NA	0.00%	NA	NA	31T	2.42%	0.18%	2.60%	1.31%	3.91%
Total Commercial & Industrial		NA	NA	0.00%	NA	NA		1.34%	0.11%	1.45%	0.72%	2.17%
Large Volume - Other than Transportation	41	1.21%	-1.20%	0.01%	0.42%	0.43%	41	1.03%	0.05%	1.08%	0.63%	1.71%
Large Volume - Transportation	41T	4.66%	-4.62%	0.04%	1.62%	1.66%	41T	3.11%	0.14%	3.25%	1.96%	5.21%
Total Large Volume		1.42%	-1.41%	0.01%	0.49%	0.50%		1.26%	0.06%	1.32%	0.78%	2.10%
Limited Interruptible	86	1.33%	-1.32%	0.01%	0.50%	0.51%	86	1.11%	0.08%	1.19%	0.62%	1.81%
Limited Interruptible - Transportation	86T	2.35%	-2.32%	0.03%	0.90%	0.93%	86T	2.40%	0.10%	2.51%	1.50%	4.01%
Total Limited Interruptible		1.34%	-1.33%	0.02%	0.50%	0.52%		1.13%	0.08%	1.21%	0.63%	1.84%

Review of Deferrals by Rate Schedule for Non-Residential Rate Groups

The electric and gas non-residential rate groups include multiple rate schedules. The purpose of this section is to separate the analysis of deferrals by each of these rate schedules. This separation is shown in Table VII-7.

Table VII-7. Allocation of Deferrals by Rate Schedule, Non-Residential Rate Groups – DR 30.70

Electric Non-Residential Rate Group	Sch 24	Sch 25	Sch 29	Sch 35	Sch 40	Sch 43	Sch 46&49	Group Total
Schedule-Level Amortization Revenue	$ 4,511,707	$ 4,723,535	$ 24,766	$ 8,251	$ 1,076,421	$ 191,448	$ 1,058,606	$ 11,594,734
Schedule Contribution to Group Deferral	$ 1,830,129	$ 4,529,065	$ (303,152)	$ (56,308)	$ 4,593,139	$ 1,320,795	$ (318,674)	$ 11,594,994
Net Deferral +Subsidizing (-Subsidized)	$ 2,681,578	$ 194,470	$ 327,918	$ 64,559	$ (3,516,719)	$ (1,129,347)	$ 1,377,280	$ (261)
Gas Non-Residential Rate Group	Sch 31	Sch 31T	Sch 41	Sch 41T	Sch 86	Sch 86T		Group Total
Schedule-Level Amortization Revenue	$ 10,727,053	$ 1,221	$ 3,581,984	$ 885,902	$ 489,373	$ 14,050		$ 15,699,581
Schedule Contribution to Group Deferral	$ 10,015,064	$ (8,790)	$ 6,851,619	$ (3,281,231)	$ 2,268,120	$ (142,646)		$ 15,702,136
Net Deferral +Subsidizing (-Subsidized)	$ 711,988	$ 10,011	$ (3,269,635)	$ 4,167,133	$ (1,778,747)	$ 156,696		$ (2,554)

Table VII-7 summarizes an analysis that estimates the revenue collected from amortization compared to the amount of deferred revenue contributed by rate schedule. Amortized revenue from each rate schedule is estimated by applying the group level amortization rate by the kWh of each schedule, ignoring the lag in deferral recovery to simplify the analysis. The schedule contribution to group deferral was determined by their contribution using actual customer counts and kWh (to ERF-level allowed revenue and rates, stripping out the K-factor) and then comparing that to the deferrals that would have resulted (by schedule) at the ERF-levels of customer counts and usage. See DR 30.70 for full details. [3]

The results in Table VII-7 show that Schedule 24, and to a lesser extent Schedules 46 & 49, has been carrying most of the responsibility for deferral payment. Schedule 40, and to a lesser extent Schedule 43, has been subsidized by these other rate schedules. Similarly, in gas rate Schedule 41T has carried a heavier deferral payment burden, subsidizing Schedule 41 and Schedule 86.

The variation in net deferral by rate schedule is due mainly to the variation in size of customer between rate schedules. The decoupling mechanism determines allowed volumetric distribution revenue per customer at the rate group level. It does not, however, determine base rates. The rate for customers in each rate schedule is determined by cost of service studies rather than the decoupling mechanism.

Section Summary

For most rate groups, the full balance of deferred revenues for amortization is placed in Schedule 142 rates with each Schedule 142 filing. In three cases, the 3% Rate Test resulted in a portion of the deferral balance (that would have been put in Schedule 142 rates) being carried forward to the next Schedule 142 filing. Such was the case with electric Schedule 31 in the 2015 filing and gas Residential (Schedules 23 & 53) in both the 2015 and the 2016 filings. Based on our review of deferred balances in the three cases where the 3% Rate Test came into play, we believe that growing deferrals in the gas Residential rate group (Schedules 23 & 53) represent a potential problem for both the customers in this rate group and for PSE.

We recommend that the Rate Test be adjusted from a 3% soft cap to a 5% soft cap to clear balances in most years while still providing a level of protection to the customer against extreme rate changes. As discussed earlier in this section, the benefit of raising the soft cap from 3% to 5% on rate increases includes better temporal alignment between incurred cost of service and the actual payment for service. This benefits both the customer class and PSE. The customer benefits by avoiding increasing levels of debt, especially during periods of warmer than normal weather and better alignment with those who incurred the debt and those who pay it. PSE benefits by faster collection of allowed revenue, although still with a lag, and compliance with Generally Accepted Accounting Practices. PSE believes that, to be consistent with Generally Accepted Accounting Practice, deferred decoupling revenue should be collected within two years of the period it was recognized.[83] PSE estimates that the $28.7 million of unamortized revenue due to the Rate Test (see last line of Table VII.2) will not be fully recovered until April of 2018.[84]

There is some evidence that weather normalized UPC for residential customers, both electric and gas, has moved lower than Test Year UPC. Typically, however, these kinds of small gradual changes can be accommodated within the 3% Rate Test. The UPC in the electric Residential group and gas Residential rate group (Schedules 23 & 53) should be monitored for persistent changes and trends in UPC.

Schedule 142 rate impacts reflect a number of things besides the amortization of decoupling deferrals, which is traditionally the only rate impact of decoupling. Included in the Schedule 142 rate impacts is the planned escalation of allowed delivery revenue (K-factor) and balances in deferral and amortization accounts due to some unique features of PSE's decoupling mechanism. It is important to note that these unique features do not impact the total revenue PSE will receive but only impact the timing of when PSE will receive these revenues.

[83] PSE response to H. GIL PEACH & ASSOCIATES Data Request No. DR 30.42.

[84] PSE response to H. GIL PEACH & ASSOCIATES Data Request No. DR 30.42.

VIII. Impact on Conservation by Schedule 26 & 31 Customers

Task element 7 in the Statement of Work calls for an evaluation of the impact on conservation achievements of rate design changes associated with the implementation of decoupling. Rate design is separate from decoupling.

Conservation achievements planned to be considered in this section include accomplishments made through PSE energy efficiency programs as well as independently acquired conservation savings (although independently acquired, conservation savings are not pursued in this study, as discussed below).

> **Task Element 7: Impact on Conservation Achievements by Schedule 26 and 31 Customers**
>
> An examination of whether and how the changes in rate design for Schedule 26 and 31 effect conservation achievement by these customers. The evaluation will examine whether there is conclusive evidence that the change had an appreciable effect on customers' energy efficiency achievements including, but not limited to, achievements made through customer participation in PSE's energy efficiency programs.

Figure VIII.1: Conservation and Schedule 26 & 31 Customers

The relevant aspect of rate design for Schedule 26 & 31 customers is the significant shift toward cost recovery through demand charges. This resulted in significantly higher demand charges and lower energy rates. At the same time that the rate design changes took effect (January 1, 2014), the decoupling mechanism for these customers was changed to work through the demand charge rather than through the energy charge. The impact of the rate redesign on rates is shown in the table below.[85]

[85] Source: PSE response to H. GIL PEACH & ASSOCIATES Data Request No. 20.44 Attachment A.

Table VIII.1: Total Winter Rates Before & After Rate Redesign (Schedule 26) and Schedule 31 – DR 20.44

Effective Date	Schedule 26		Schedule 31	
Effective Date	Rate Per kWh	Rate Per kW	Rate Per kWh	Rate Per kW
July 1, 2013	$ 0.062539	$ 8.94	$ 0.060379	$ 8.64
January 1, 2014	$ 0.056733	$ 11.53	$ 0.054347	$ 11.13
Percent Change	-9%	29%	-11%	29%

The winter (October through March) rates for Schedule 26 and Schedule 31 are shown in the table (above) to illustrate the nature and magnitude of the rate. Percentage changes are similar across seasons. The shift in billing away from energy usage and toward demand is evident and resulted in nearly 30% higher demand charges and about 10% lower energy charges.

As shown in Figure VIII.2, the higher kW rate with redesign is due almost entirely to the new higher base rate per kW with only 3% to 4% of the total kW charge coming from Schedule 142.

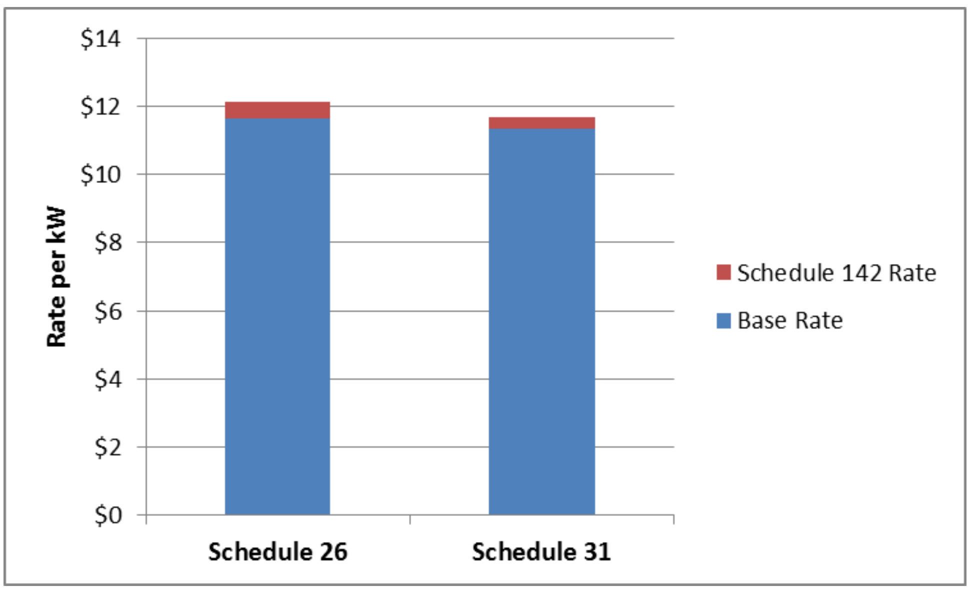


Figure VIII.2: Average Winter Rate per kW since January 2014 – DR 20.44

For Schedule 26 and Schedule 31 customers, Schedule 142 rates account for a small portion of kW charges. It is clear that the rate design that became effective January 1, 2014 resulted in significantly higher demand charges and that the Schedule 142 adjustment has been only a small part of the demand rate increase.

We next turn to the question of how, if at all, the rate design change impacted conservation achievements of Schedule 26 and Schedule 31 customers. The rest of this section of the study addresses this question.

Conservation through PSE Energy Efficiency Programs

PSE provided detailed records for conservation projects undertaken by Schedule 26 and 31 customers through PSE energy efficiency programs.[86] The records provided include customer rate schedules, conservation schedules, estimated energy savings, date completed and other variables relevant to conservation project tracking. These project specific records were used to summarize conservation achievements over the last three evaluation years and for one year prior to decoupling. Conservation achievements are shown for these periods in Figure VIII.3.

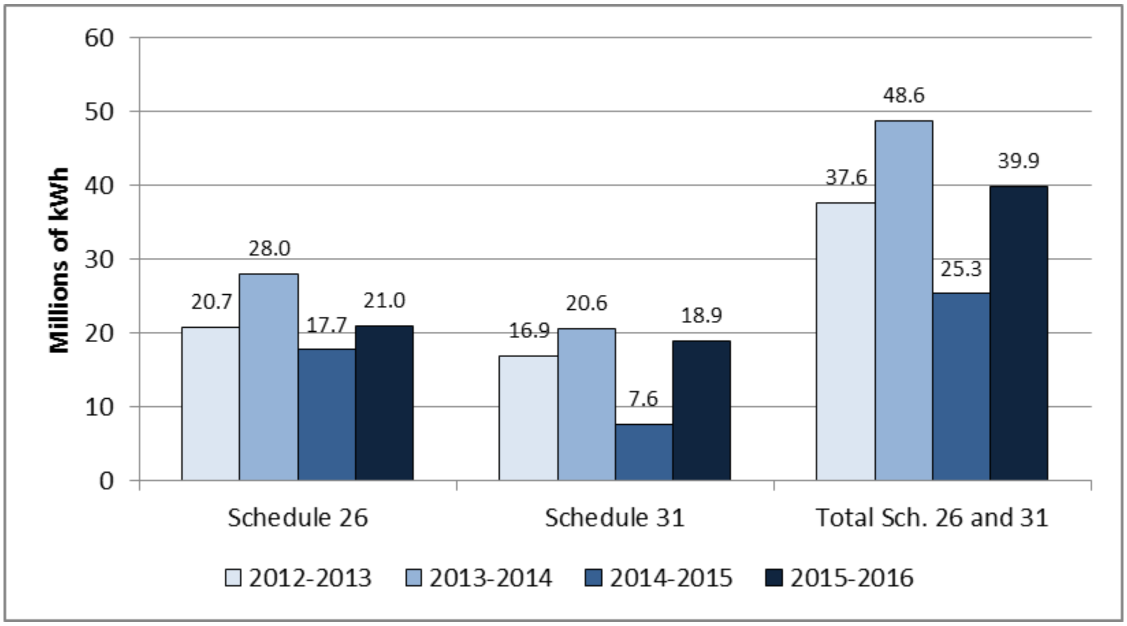


Figure VIII.3: Schedule 26 & 31 Customers, Electric Conservation Achievement – DR 01.25, 20.14, 30.14

Conservation achievements for customers on both rate schedules 26 and 31 have followed a saw tooth pattern since decoupling; increasing in the year ending June 2014 and then falling in the year ending June 2015 before rising again in the year ending June 2016. For the year ending June 2016, conservation achievements exceeded the year preceding decoupling, ending July 2013.

The seemingly erratic pattern of conservation achievements evident in the up and down pattern shown in Figure VIII.3 is typical of large customers. Conservation projects for large business customers can take several months to plan and implement and, to be effective, require extensive organizational effort. They are also often quite large in magnitude. These factors may cause the timing of savings to jump around from year to year depending on when projects reach the completed stage and are counted as savings.

[86] See PSE response to H. GIL PEACH & ASSOCIATES Data Request No. 01.25, Attachment A; No. 20.14, Attachment A; and 30.14 with 30.14 Attachment A.

Conservation Beyond PSE Energy Efficiency Programs

It was decided not to run special surveys to gather this information, so the information is not included in this report. The basic problem was that special surveys would likely not have returned useful quantitative information:

- A qualitative survey aimed at understanding (or what social scientists like to call a "grounded theory" or "Verstehen" approach) would have developed categories of independent projects without being able to determine quantitative results. It might provide some insights, but results could not be quantified. Results would not be useful for calculations.

- The other alternative, a full set of quantitative surveys, would be expected to have a high non-response rate so that a reported precision and confidence would not be true; and it would involve more than one survey per customer and a high cost, for large customers. The required size of an effective quantitative effort would have been out of scope for the evaluation budget (and would have taken resources from other required areas of the evaluation).[87]

Attribution in Conservation Achievements

Would a higher demand rate (and a corresponding lower energy rate) find a reflection in these customers' incentive to conserve by materially reducing the payback for conservation? Although we now have three years of actual experience to examine, it is not possible to derive firm conclusions regarding the influential factors behind the change in conservation achievements. The pattern of achievements is initially increasing, then declining and rising again to a level higher than the year prior to decoupling. Our conclusions based on data thus far available are as follows:

- The rate redesign for Schedule 26 and Schedule 31 resulted in a significant shift away from energy and to demand changes. Almost all of the increase in demand changes was due to rate redesign. The decoupling surcharge for these customers, as applied to kW, was small and the surcharge changed little over the first three decoupling rate years. The overall electric energy savings first increase, then fall

[87] By analogy, it would be like an elephant and a mouse, with the elephant being the survey budget required to develop reasonably precise results based on sample design and probability theory (rather than a set of heroic assumptions and adjustments) and the mouse being the existing evaluation budget.

and then increase to levels higher than the pre-decoupling period, suggesting that customers are making conservation decisions independent of the rate redesign.

- The underlying reality is that customers have an economic reason to adopt cost effective conservation regardless of the presence or absence of the decoupling mechanism and associated rate. Regardless of the mechanism used to recover energy efficiency program costs from customers, customers who participate in programs to lower their usage receive the benefit of lower usage while costs are spread over all customers – those who do and do not participate. Decoupling does not change the individual cost-benefit analysis of conservation adoption facing each customer.

- In our experience, projects in this sector are particularly "large and lumpy" and take a comparatively long lead-time to secure corporate approvals and to execute. A swing of roughly 30% or 40% is typical for this sector.[88] We have assessed energy savings from programs in other jurisdictions for several years and find that goal achievement for large custom projects in this sector is typically much lower or, alternatingly, much higher than planned due to the size of the projects. At the end of each program cycle, it is not unusual for some large industrial and commercial projects to significantly lag the plan; but if a few more than usual are finished just prior to the new cycle, the result is to significantly exceed the plan. This long-term experience coincides with PSE's statement that "The majority of savings from this program occur between the last quarter and the first quarter of each two-year cycle."[89] Conservation projects for large business customers tend to have relatively large savings and may take several months to develop and implement. This can result in significant impacts on annual savings depending on when these projects are registered as complete. This causes savings to exhibit greater volatility between years and happens regardless of decoupling.

- Changing levels of energy efficiency potential are another possible factor in the change in conservation achievements of Schedule 26 and 31 customers. PSE provided annual energy efficiency goals developed on the basis of a Conservation Potential Assessment developed by Cadmus Group for the 2015 Integrated Resource Plan. Using data from this study, PSE Resource Planning, in concert with

[88] Note that here we are focused on only large customers with large projects so that the number of smaller energy efficiency projects cannot damp down these swings.

[89] This long-term experience coincides with PSE's statement that "The majority of savings from this program occur between the last quarter and the first quarter of each two-year cycle." See the discussion of the "hockey stick" effect in the response to H. GIL PEACH & ASSOCIATES Data Request No.20.14 and 30.14.

PSE Energy Efficiency, developed the conservation goals consistent with Council methodology and with the engagement of the Conservation Resource Advisory Group (CRAG). Goals are presented by conservation program (which are primarily assigned by Conservation Schedule; for instance, Schedule 250 applies to Commercial/Industrial Retrofit) and summed for all business programs. Because Schedule 26 and 31 customers participate across all business programs, the goal for all business programs is used.[90] A summary of annual conservation goals for all Business Programs is shown in the table below.

Year	MWH	Percent Change	Therms (millions)	Percent Change
2011	177,719		2.675	
2012	159,800	-10%	2.985	12%
2013	156,980	-2%	2.643	-11%
2014	130,962	-17%	1.443	-45%
2015	112,126	-14%	1.612	12%
2016	133,570	19%	1.674	4%

Table VIII.2: Annual Electric Conservation Goals, Business Energy Management – DR 1.21, 20.15, 20.45, 30.15

These goals, developed by calendar year, are useful for tracking changing market conditions. From 2011 until 2016, there is a clear downward trend in the electric savings goals, indicating that market potential (under current benefit/cost calculation methods) has fallen significantly in the business sector. Conservation achievements in Schedule 26 and Schedule 31 customers have outperformed the potential in the business sector suggested from the goals in Table VIII.2. The 2016 MWH target of 133,570 is 85% of the 2013 target. However, conservation achievements for Schedule 26 and Schedule 31 customers for the year ending June 2016 of 39.9 million kWh were 6% higher than achievements for the year preceding decoupling ending June 2013 (See Figure VIII.3).

Decoupling has clearly not hampered conservation achievements of Schedule 26 and Schedule 31 customers. However, the PSE 2015 Annual Report of Energy Conservation Achievements suggests the trend towards decreased savings "…reflects the market saturation of several key measures, revisions to measure UES values, updated energy codes, some increased incentive amounts, marketing efforts, and staff rigor required to achieve ambitious savings goals while

[90] See PSE response to H. GIL PEACH & ASSOCIATES Data Request No. 1.21, Attachment A, B, C, and D and to H. GIL PEACH & ASSOCIATES Data Request 20.15, Attachment A and 30.15 Attachment A. Also see PSE response to H. GIL PEACH & ASSOCIATES Data Request 20.45, referenced links to the 2013 Integrated Resource Plan and Attachment A for additional information on how PSE used Cadmus IRP information in establishing conservation targets.

sustaining prudent use of customer funding."[91] The 2016-2017 Biennial Conservation Plan reports on planned energy savings. PSE uses a continuous improvement perspective and, as a result of increased incentives, improved marketing plans and decline in cost of LED technology (including tubular LEDs for business applications), PSE anticipates a small overall increase in business energy savings. "Large power users and new construction projects are forecast to increase substantially in the next two years. The large power user increase is driven by the increased allocation funding for the program and the timing of the RFP cycle."[92]

Section Summary

In summary, with three years of data, our general finding is that we see a "business as usual" pattern for these schedules, in a context of declining returns under the current DSM paradigm, with no discernable change in conservation achievements from Schedule 26 and Schedule 31 customers attributable to either the rate redesign or decoupling. This is not conclusive evidence, but it is the pattern we see in the data.

[91] Puget Sound Energy, *2015 Annual Report of Energy Conservation Accomplishments,* Section 4, Five Year Trends, P. 11.

[92] Source: 2016-2017 Biennial Conservation Plan, Executive Summary, P. 7, and full report.

IX. Facing Forward

We end the study with a short look forward and a brief review of evaluation results. The look forward outlines and embraces opportunity for increased value. Looking back through evaluation documents the story so far.

Looking Forward

Research by Cadmus in support of PSE's newest Integrated Resource Plan shows substantial future achievable potential.[93] This new information fits into the concept of Demand-Side Management proceeding in "waves:" as a set of measures and programs begin to decline in savings, another wave of measures (for example, the tube LED lamps) and programs come in on the next wave. Along these lines, and facing forward, we would like to offer the following brief comments on potential, which we see as substantial, based on our work in other jurisdictions. Other forces are at work including the beginning of practical effort in climate adaptation and independent market forces. With regard to considerations of market potential, it is important that in four jurisdictions (New York[94], California[95], Massachusetts and Connecticut), even as traditional utility DSM programs are ramped, DSM is being seen as coming to be replaced in a wider vision that includes Distributed Energy Resources (DER), Distributed Energy Resources Management (DERM), micro-grids that can combine traditional generation, renewables (particularly solar and wind with their continuing increases in efficiency and decreasing cost), Demand Response (DR) and DSM in localized micro-grid packages. If new battery technologies perform as expected and at a reasonable price point, their addition to microgrids has a substantial potential to replace some older baseload plants and to keep newer baseload plants cost-effective.

Of course, the idea of microgrids with DER, including batteries, is not really new, though it is now put forward as a Reforming the Energy Vision (REV) by the New York Department of Public Service, for climate goals by the California Public Utility Commission and as pragmatic next steps in Connecticut and Massachusetts as well as in individual utility or utility/USDOE pilots in several states including Illinois, Pennsylvania and Maryland. When the silos that traditionally

[93] The 2015 Puget Sound Energy, Inc. Integrated Resource Plan was supported by research effort from Cadmus. See: http://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx. This information was provided in response to H. GIL PEACH & ASSOCIATES Data Request No. 20.31.

[94] We have served as an advisor for the NY Department of Public Service since 2009.

[95] We are working with engineers in California in the context of California's climate research and climate adaptation efforts and other projects with inclusive project boundaries.

separate DSM energy savings programs, Demand Reduction (DR) programs, renewable and non-renewable DERs, DERMs and energy storage are joined together (either from a market perspective or from a climate adaptation perspective), DSM becomes a subcomponent of an ecology of intelligent micro-grids. This opens a whole new cycle of possibilities with very high potential, particularly in the context of state, county and city climate adaptation goals. And, with climate change already here and moving much more rapidly than recently projected, there is strong motivation to move to increasing system resilience and to include what happens on the customer side of the meter in formulating plans.

It looks like progress will develop along the lines sketched out in this section and we can look forward to more waves of increasingly cost-effective programs, but with very different project boundaries, that break across several existing silos to release new value. The decoupling of revenues from sales levels can play an important role in removing financial disincentives that may be facing utilities that support these programs.

Looking Back through Evaluation

We now turn from a vision facing forward to a look back at what has developed through the first three years of evaluation. We bring this study to a close with the following statements for the three years examined.

For the three-years examined:

(1) We find that the decoupling mechanism worked as intended. The control tool that limits overall rate increase for a decoupling group (set of rate schedules) worked as planned, limiting rates and deferring unrealized revenue recovery to a future year. The earning test tool also worked exactly as planned, returning funds to customers when there was an over-collection.

(2) There was a surprise: For a single natural gas decoupling group with high sensitivity of energy usage in relation to temperature (residential natural gas – Schedules 23 & 53), full recovery of automatically deferred revenue was not complete within two years. Deferral went into a second year and appeared likely to go into a third. PSE estimates that, for the residential gas decoupling group, the $8.7 million in unamortized revenue due to the rate test will not be fully recovered until April 2018. This occurred due to the operation of the cap at the three percent (3%) level and the nature of the weather – warming occurs in short warming cycles across years. Years are not independent of each other for warming and cooling. The mechanisms of the pilot worked exactly as planned, but unrealized revenue crossed more than two years. This cumulative effect is a simple function of the level of the cap and a typical warming cycle.

(3) Four performance indicators are out of range for 2015. We interpret this as due to weather events. However, these indicators should be watched for 2016 and 2017 to make sure they are one-time events.

(4) Although theoretical concerns about bill increases and the motivation to do good work are sometimes raised in the planning phase for decoupling, we did not find these to be operative in the three years studied.

(5) In this case study, decoupling is a careful and incremental reform with positive features, such as increasing the surety of revenue recovery and removing potential barriers to conservation. (As conservation was already good prior to decoupling, we did not detect a difference.) It supports an organizational reality in which it is acceptable for staff to exceed saving goals and in which DSM is part of a positive organizational outlook.

(6) However, though decoupling removes barriers, it does not create a “demand-pull.” There is no “pulling force” because it does not have the “Decoupling 2.0”[96] monetization of incentives for the utility.

(7) The size of the decoupling adjustment each year, for each decoupling group over the three years studied, is small: small enough so as not to influence customer energy conservation; small enough to be within general customer experience of normal energy cost variations due to seasonality and weather cycles from year to year.

(8) The size of the cumulative decoupling adjustment for a set of warm years for the residential natural gas (Schedule 23 & 53) group (and only for this one group) will increment from 3% to 6%, 9%, 12%, and 15%, etc., depending on the span of the short warming cycle. Then, during the following cooling cycle, the deferred revenue will be collected and, if the cooling cycle continues, the adjustment mechanism will eventually reset.

[96] Decoupling 2.0 is a shorthand way that people working on evaluation of decoupling refer to the addition to the decoupling mechanism of one or more reliable new revenue streams for the utility for meeting or surpassing energy efficiency and conservation (and possibly including distributed energy resource, demand control or micro-grid) goals. These goals could be of any type. The critical concept is to create a “demand-pull” that creates a continuing revenue stream by monetizing some of the values attached to the goals. In discussion about decoupling, the kind of decoupling in play for PSE for the time window studied would be called “Decoupling 1.0”. Though the K-factor is an add-on, it does move the mechanism to Decoupling 2.0. If values of energy efficiency and conservation (and possibly including micro-girds, distributed energy resources and demand control) were partially monetized to create one or more reliable and continuing payment streams to the utility, we would call the combined package “Decoupling 2.0”.

(9) If households have insufficient income, they will have trouble with energy bills. PSE HELP funding is essential. Federal low-income support is also very important but is erratic as to amount and timing. In every customer class, customers who use more energy will have higher energy bills and customers who use less energy will have lower energy bills. This reality is independent of decoupling. To bring bills into line with household ability to pay, decoupling is not an answer. PSE would need to consider a low-income rate based on ability to pay.

(10) *Decoupling works*. Generally, PSE decoupling operated as expected. However, it was expected that deferred revenue would be amortized within one year after the year in which the energy was delivered to the customer, causing transactions to balance within two years. For the natural gas residential group (Schedules 23 & 53), deferred revenue accumulated from the second to the third year. We suggest that the potential problem of growing deferral balances be addressed by raising the Rate Test from 3% to 5% for the residential natural gas decoupling group only. Otherwise the cap can remain at 3%. We find that the decoupling mechanism worked as intended.

X. Reference Appendix I – Conservation Savings and Expenditures

Reference Appendix 1, which follows this page, is an extract of PSE's 2011-2016 Exhibit 1: Savings and Expenditures from its Annual Report of Energy Conservation Accomplishments. (Note that the version of the 2016 Exhibit 1 included here does not complete the entire year, running only through September 16, 2016.)

Exhibit 1

Energy Efficiency Services

PUGET SOUND ENERGY, INC.
ELECTRIC RIDER & GAS TRACKER CONSERVATION EXPENDITURES & SAVINGS
January - December 2011

100%	of year 2011		Electric						Gas					
Electric Schedule	Gas Schedule	Programs (Manager Name)	YTD Actual		Percentage		Budget		YTD Actual		Percentage		Budget	
			$ Spent	MWh Svgs.	% of $ Budget	% of Svgs. TOTAL	$ BUDGET	MWh Svgs. Target	$ Spent	Therms Svgs.	% of $ Budget	%of Svgs. TOTAL	$ BUDGET	Therms Svgs. Target
		Residential Programs:												
E214	G214	Single Family Existing	$ 17,753,219	110,163	90%	101%	$ 19,691,227	109,501	$ 3,774,794	1,106,352	49%	61%	$ 7,663,374	1,821,743
E217	G217	Multi Family Existing	$ 5,004,759	17,852	95%	102%	$ 5,246,290	17,463	$ 297,136	35,079	49%	42%	$ 606,776	83,713
E216		Single Family Fuel Conversion	$ 429,864	1,607	43%	38%	$ 1,003,618	4,249						
E215	G215	Single Family New Construction	$ 852,860	1,541	58%	50%	$ 1,463,949	3,094	$ 443,424	60,594	67%	59%	$ 665,394	102,850
E201	G203	Low Income Weatherization	$ 2,287,825	1,965	96%	131%	$ 2,391,463	1,501	$ 712,248	50,745	80%	110%	$ 889,379	46,020
		LIW REC Funding (Not Rider/Tracker) [1]	$ 1,925,015	1,750	84%	157%	$ 2,285,000	1,112						
E218	G218	Multi Family New Construction	$ 518,230	1,082	73%	92%	$ 708,536	1,175	$ 236,792	26,161	76%	75%	$ 310,921	34,702
E200	G206	Residential Energy Efficiency Information	$ 1,086,006	n/a	93%	n/a	$ 1,166,306	n/a	$ 540,093	0	111%	0%	$ 486,267	-
E202	G207	Energy Education	$ 114,811	0	58%	n/a	$ 199,053	n/a	$ 37,571	0	75%	0%	$ 49,765	-
E249	G249	Pilots[2], excluding:	$ 73,367	292	32%	39%	$ 227,024	758	$ 146,378	46,440	130%	184%	$ 112,397	25,200
		Home Energy Reports	$ 613,126	5,093	71%	n/a	$ 868,123	n/a	$ 211,016	321,006	83%	#DIV/0!	$ 255,644	-
		Total Residential Programs	**$ 28,734,067**	**141,345 MWh**	**87%**	**103%**	**$ 32,965,589**	**137,741 MWh**	**$ 6,399,452**	**1,646,377**	**58%**	**78%**	**$ 11,039,916**	**2,114,228 Therms**
		Business Efficiency Programs												
E250	G205	C/I Retrofit	$ 18,498,136	79,596	92%	102%	$ 20,071,487	78,000	$ 4,776,988	1,076,951	117%	138%	$ 4,083,403	781,000
E253	G208	Resource Conservation Manager - RCM	$ 1,035,282	25,191	58%	78%	$ 1,797,897	32,500	$ 662,184	1,432,151	87%	102%	$ 763,386	1,400,000
E255		Small Business Lighting Rebate	$ 7,465,414	25,059	108%	109%	$ 6,910,836	23,000						
E251	G251	C/I New Construction	$ 7,849,113	18,438	95%	119%	$ 8,249,734	15,500	$ 2,195,441	468,685	148%	164%	$ 1,487,218	286,000
E262	G262	Business Rebates	$ 2,482,425	25,227	94%	176%	$ 2,640,768	14,319	$ 466,668	562,557	91%	270%	$ 514,352	208,250
E258		Large Power User - Self Directed	$ 1,744,567	9,394	27%	68%	$ 6,568,725	13,900						
E257		LED Traffic Signals	$ 33,510	1,176	100%	235%	$ 33,543	500						
E260	G260	Business Energy Efficiency Information	$ 48,937	0	31%	n/a	$ 160,276	0	$ 35,072	0	34%	0%	$ 103,720	-
		Gas Conservation Comm/Ind Tracker AFUCE[3]							$ 1,035					
		Total Business Programs	**$ 39,157,384**	**184,080 MWh**	**84%**	**104%**	**$ 46,433,266**	**177,719 MWh**	**$ 8,137,388**	**3,540,344**	**117%**	**132%**	**$ 6,952,079**	**2,675,250 Therms**
		Regional Efficiency Programs												
E254		NW Energy Efficiency Alliance (Anderson)	$ 5,241,606	23,500	100%	100%	$ 5,260,640	23,500						
		Efficiency Support Activities												
		Program Evaluation	$ 1,546,379	n/a	98%	n/a	$ 1,581,303	n/a	$ 451,865	n/a	114%	n/a	$ 397,475	n/a
		Verification Team	$ 79,894	n/a		n/a		n/a	$ 15,345	n/a		n/a		n/a
		Strategic Planning & Market Research	$ 591,574	n/a	63%	n/a	$ 945,016	n/a	$ 150,215	n/a	64%	n/a	$ 236,254	n/a
		Mainstreaming Green	$ 293,364	n/a	57%	n/a	$ 511,000	n/a	$ 128,847	n/a	59%	n/a	$ 219,000	n/a
		Conservation Supply Curves[4]	$ 197,635	n/a	63%	n/a	$ 315,064	n/a	$ 55,889	n/a	71%	n/a	$ 78,766	n/a
		EES Market Integration	$ 173,193	n/a	65%	n/a	$ 265,625	n/a	$ 69,011	n/a	61%	n/a	$ 113,825	n/a
		Energy Efficient Green Communities	$ 174,647	n/a	72%	n/a	$ 243,545	n/a	$ 69,443	n/a	76%	n/a	$ 91,955	n/a
E270	G270	Local Infrastructure& Mkt Transformation	$ 43,240	n/a	61%	n/a	$ 71,049	n/a	$ 3,276	n/a	7%	n/a	$ 44,302	n/a
E261	G261	Energy Efficient Technology Evaluation	$ 667	n/a	4%	n/a	$ 18,777	n/a	$ 235	n/a	1%	n/a	$ 18,811	n/a
		Third-Party Evaluation Review (per condition K(6)(g))					$ 250,000							n/a
		Program Support	$ 214,209	n/a	51%	n/a	$ 417,257	n/a	$ 8,449	n/a	10%	n/a	$ 88,073	n/a
		Total Efficiency Support Activities	**$ 3,314,801**	**0**	**72%**	**0%**	**$ 4,618,636**	**0**	**$ 952,574**	**0**	74%	**n/a**	**$ 1,288,461**	-
		SUBTOTAL ELECTRIC ENERGY EFFICIENCY	**$ 76,447,858**	**348,926 MWh**			**$ 89,278,131**	**338,960 MWh**	**$ 15,489,414**	**5,186,721 Therms**			**$ 19,280,456**	**4,789,478 Therms**
			85.6%	**102.9%**										
		Total aMW Savings		**39.8 aMW**				**38.7 aMW**						
		Other Electric Programs [5]												
E249A		Residential Demand Response Pilot	$ 648,350	n/a	104%	n/a	$ 621,008	n/a	n/a	n/a	n/a	n/a	n/a	n/a
E248		Renewable Energy Education[6]	$ 267,752	n/a	77%	n/a	$ 348,659	0	n/a	n/a	n/a	n/a	n/a	n/a
E150		Net Metering	$ 229,346	n/a	83%	n/a	$ 277,687	n/a	n/a	n/a	n/a	n/a	n/a	n/a
E249A		C/I Load Control Pilot	$ 272,242	n/a	101%	n/a	$ 268,419	n/a	n/a	n/a	n/a	n/a	n/a	n/a
		Total Other Electric Programs	**$ 1,417,689**	**0 MWh**	**94%**	**0%**	**$ 1,515,773**	**0 MWh**						
		GRAND TOTAL ENERGY EFFICIENCY	**$ 77,865,547**	**348,926 MWh**			**$ 90,793,904**	**338,960 MWh**	**$ 15,489,414**	**5,186,721 Therms**			**$ 19,280,456**	**4,789,478 Therms**
		Total aMW Savings		**39.8 aMW**				**38.7 aMW**						
			85.8%	**102.9%**										
		PSE LIW Funding[7]		n/a		n/a		n/a	$ 259,913	n/a	87%	n/a	$ 300,000	n/a

Footnotes

1 LIW REC funding is reporting savings, but the source of funding is recorded against O&M budget. Figures noted in blue highlighting are included only to provide perspective for savings claims. These figures are EXCLUDED from the indicated Residential expenditure and budget subtotals.
2 Pilots = LED lamps, Heat Pump Sizing & Lock out Controls
3 Noted figure is not actual AFUCE. Actual cost is for printing, which was recognized against an incorrect order number. It wasn't possible to journal entry after year-end. The figure is included for transparency.
4 Conservation Supply Curves, associated with Resource Planning, is included in the EES R/T budget because EES pays part of two RP staff salary.
5 Other Electric programs are separated because they are not included in cost effectiveness calculations.
6 Renewable Energy Education, Schedule 248, was formerly referred to as Small Scale Renewables.
7 LIW shareholder funding is not limited to the gas fuel type. Condition G(14) indicates that $300,000 in shareholder funding may be applied to electric or gas LIW.

Exhibit 1

PUGET SOUND ENERGY, INC.
ELECTRIC RIDER & GAS TRACKER CONSERVATION EXPENDITURES & SAVINGS
January - December 2012

CustomerSolutions

Electric Schedule	Gas Schedule	Programs (Manager Name) — Through December 2012	Electric YTD Actual $ Spent	Electric YTD Actual MWh Svgs.	Electric Percentage % of $ Budget	Electric Percentage % of Svgs. TOTAL	Electric Budget $ BUDGET	Electric Budget MWh Svgs. Target	Gas YTD Actual $ Spent	Gas YTD Actual Therms Svgs.	Gas Percentage % of $ Budget	Gas Percentage %of Svgs. TOTAL	Gas Budget $ BUDGET	Gas Budget Therms Svgs. Target
		Residential Programs:												
E201	G203	Low Income Weatherization	$ 2,414,265	1,606	82%	76%	$ 2,946,378	2,100	$ 378,512	22,622	63%	53%	$ 604,593	42,300
E214	G214	Single Family Existing	**$ 25,331,918**	**124,796**	**84%**	**100%**	**$ 30,332,921**	**125,400**	**$ 4,892,049**	**1,606,987**	90%	92%	**$ 5,442,844**	**1,739,615**
		Residential Lighting	*$ 12,605,565*	*86,687*	*99%*	*120%*	*$ 12,738,452*	*72,300*	$ -		n/a		$ -	-
		Space heat	*$ 2,968,354*	*7,345*	*113%*	*124%*	*$ 2,638,136*	*5,900*	*$ 1,344,372*	*471,295*	*64%*	63%	*$ 2,113,267*	*742,700*
		Water heat	*$ 253,881*	*580*	*80%*	*73%*	*$ 317,119*	*800*	*$ 5,733*	*0*	*n/a*	0%	$ -	-
		HomePrint	*$ 1,054,381*	*1,942*	*59%*	*47%*	*$ 1,789,987*	*4,100*	$ -	*0*	*n/a*	0%	$ -	-
		Home Appliances	*$ 5,314,655*	*8,627*	*65%*	*34%*	*$ 8,125,988*	*25,100*	$ -	*29,463*	*n/a*	72%	$ -	*40,915*
		Showerheads	*$ 300,736*	*5,691*	*160%*	*407%*	*$ 188,495*	*1,400*	*$ 195,035*	*221,179*	*89%*	334%	*$ 219,746*	*66,300*
		Manufactured Homes								*0*				
		Weatherization	*$ 2,753,655*	*8,425*	*64%*	*82%*	*$ 4,319,891*	*10,300*	*$ 3,316,554*	*538,326*	*110%*	95%	*$ 3,012,163*	*543,000*
		Home Energy Reports	$ 80,691	5,498	38%	*100%*	*$ 214,853*	*5,500*	*$ 30,356*	*346,724*	*31%*	100%	*$ 97,668*	*346,700*
		Web-Enabled Thermostat							$ -					
E215	G215	Single Family New Construction	$ 1,301,065	1,496	117%	100%	$ 1,111,043	1,500	$ 159,626	744	52%	2%	$ 309,171	31,900
E215		Energy Star Manufactured Homes	$ 3,817											
E216		Single Family Fuel Conversion	$ 540,306	1,532	67%	61%	$ 803,973	2,500	$ -					
E217	G217	Multi Family Existing	$ 10,247,241	22,952	149%	137%	$ 6,887,604	16,800	$ 451,953	90,156	200%	361%	$ 226,525	25,000
E218	G218	Multi Family New Construction	$ 542,894	961	88%	96%	$ 617,485	1,000	$ 221,598	33,026	63%	62%	$ 353,589	53,600
E249	G249	Pilots	$ -	0	0%		$ -	0	$ 479	0			$ -	-
		Total Residential Programs	**$ 40,381,507**	**153,343 MWh**	**95%**	**103%**	**$ 42,699,404**	**149,300 MWh**	**$ 6,104,217**	**1,753,535**	**88%**	**93%**	**$ 6,936,722**	**1,892,415 Therms**
		Business Efficiency Programs												
E250	G205	Commercial Industrial Retrofit	$ 18,943,779	70,516	94%	103%	$ 20,084,250	68,500	$ 4,628,670	873,098	160%	183%	$ 2,895,320	478,000
E251	G251	Commercial Industrial New Construction	$ 2,181,743	5,268	99%	151%	$ 2,214,170	3,500	$ 694,300	129,777	114%	130%	$ 609,350	100,000
E253	G208	Resource Conservation Manager - RCM	$ 1,044,155	16,026	52%	80%	$ 1,993,900	20,000	$ 550,738	1,109,236	49%	111%	$ 1,119,120	1,000,000
E255		Small Business Lighting Rebate	$ 4,967,718	16,999	66%	71%	$ 7,548,030	24,100	$ -					
E258		Large Power User - Self Directed 449	$ 2,222,424	5,530	134%	105%	$ 1,653,936	5,280					$ -	-
E258		Large Power User - Self Directed Non 449	$ 4,982,409	16,953	142%	151%	$ 3,514,614	11,220					$ -	-
E261	G261	Energy Efficient Technology Evaluation	$ -	n/a			$ -	n/a	$ -	n/a	0%		$ 27,300	n/a
E262/251	G262	Business Rebates	$ 6,172,499	35,456	128%	130%	$ 4,832,280	27,200	$ 463,016	1,338,854	72%	95%	$ 640,900	1,407,000
		Total Business Programs	**$ 40,514,727**	**166,747 MWh**	**97%**	**104%**	**$ 41,841,180**	**159,800 MWh**	**$ 6,336,725**	**3,450,965**	**120%**	**116%**	**$ 5,291,990**	**2,985,000 Therms**
		Regional Efficiency Programs												
E254		NW Energy Efficiency Alliance	$ 4,687,146	19,400	89%	100%	$ 5,260,640	19,400	$ -	n/a	n/a	n/a	n/a	n/a
E292		Generation, Transmission and Distribution	$ -	0		0%	$ -	8,100	$ -	n/a	n/a	n/a	n/a	n/a
		Total Regional Programs	**$ 4,687,146**	**19,400**	**89%**	**71%**	**$ 5,260,640**	**27,500**						
		EES Portfolio Support												
		Customer Engagement and Education	**$ 1,179,797**	**n/a**	**72%**	**n/a**	**$ 1,635,405**	**n/a**	**$ 232,132**	**n/a**	**95%**	**n/a**	**$ 244,795**	**n/a**
		Energy Advisors	*$ 742,603*	*n/a*	*72%*		*$ 1,036,907*	*n/a*	*$ 151,200*	*n/a*	*98%*	*n/a*	*$ 154,772*	*n/a*
		Events	*$ 298,869*	*n/a*	*72%*		*$ 414,363*	*n/a*	*$ 47,912*	*n/a*	*76%*	*n/a*	*$ 62,631*	*n/a*
		Brochures	*$ 45,981*	*n/a*	*85%*		*$ 54,250*	*n/a*	*$ 12,235*	*n/a*	*150%*	*n/a*	*$ 8,169*	*n/a*
E202	*G207*	*Education*	*$ 92,345*	*0*	*71%*	*n/a*	*$ 129,885*	*n/a*	*$ 20,785*	*n/a*	*108%*	*n/a*	*$ 19,223*	*n/a*
		CS Web Experience	**$ 873,838**	**n/a**	**89%**	**n/a**	**$ 982,558**	**n/a**	**$ 155,496**	**n/a**	**105%**	**n/a**	**$ 147,442**	**n/a**
		Customer Online Experience	*$ 634,822*	*n/a*	*100%*	*n/a*	*$ 635,950*	*n/a*	*$ 100,993*	*n/a*	*106%*	*n/a*	*$ 95,650*	*n/a*
		Online customer tools							*$ -*	*n/a*				
		E-news	*$ 1,781*						*$ 1,077*	*n/a*				
		Market Integration	*$ 237,235*	*n/a*	*68%*	*n/a*	*$ 346,608*	*n/a*	*$ 53,426*	*n/a*	*103%*	*n/a*	*$ 51,792*	*n/a*
		Energy Efficient Communities	$ 251,803	n/a	89%	n/a	$ 282,827	n/a	$ 63,948	n/a	151%	n/a	$ 42,263	n/a
		Trade Ally Support	$ 36,517	n/a	79%	n/a	$ 46,300	n/a	$ -	n/a	0%	n/a	$ 18,000	n/a
		Marketing Research	$ 251,392	n/a	44%	n/a	$ 567,191	n/a	$ 37,693	n/a	44%	n/a	$ 84,752	n/a
		Total Portfolio Support	**$ 2,593,348**	**n/a**	**74%**	**n/a**	**$ 3,514,281**	**n/a**	**$ 489,269**	**n/a**	**91%**	**n/a**	**$ 537,252**	-
		EES Research & Compliance												
		Conservation Supply Curves	$ 388,262	n/a	92%	n/a	$ 423,659	n/a	$ 88,666	n/a	140%	n/a	$ 63,306	n/a
		Strategic Planning	$ 98,033	n/a	28%	n/a	$ 350,289	n/a	$ 17,685					
		Program Evaluation	$ 1,745,480	n/a	86%	n/a	$ 2,021,028	n/a	$ 514,680	n/a	101%	n/a	$ 508,480	n/a
		Program Support	$ 281,686	n/a	75%	n/a	$ 376,970	n/a	$ 23,503	n/a	39%	n/a	$ 60,435	n/a
		Verification Team	$ 432,335	n/a		n/a	$ -	n/a	$ 77,812	n/a		n/a	$ -	n/a
		Total Research & Compliance	**$ 2,945,796**	**n/a**	**93%**	**n/a**	**$ 3,171,946**	**n/a**	**$ 722,346**	**n/a**	**114%**		**$ 632,221**	-
		SUBTOTAL CUSTOMER SOLUTIONS - ENERGY EFFICIENCY	**$ 91,122,524**	**339,491 MWh**	**94.4%**	**100.9%**	**$ 96,487,451**	**336,600 MWh**	**$ 13,652,557**	**5,204,500 Therms**	**101.9%**	**106.7%**	**$ 13,398,185**	**4,877,415 Therms**
		Total aMW Savings		**38.8 aMW**				**38.4 aMW**						
		Other Electric Programs [1]												
E150		Net Metering	$ 362,556	n/a	124%	n/a	$ 292,518	n/a	n/a	n/a	n/a	n/a	n/a	n/a
E248		Renewable Energy Education[2]	$ 104,074	n/a	73%	n/a	$ 142,463	0	n/a	n/a	n/a	n/a	n/a	n/a
E271		C/I Demand Response	$ 99,617	n/a	8%	n/a	$ 1,176,490	n/a	n/a	n/a	n/a	n/a	n/a	n/a
E249A		Residential Demand Response Pilot	$ 86,099	n/a	230%	n/a	$ 37,490	n/a	n/a	n/a	n/a	n/a	n/a	n/a
		Total Other Electric Programs	**$ 652,346**	**0 MWh**	**40%**	**0%**	**$ 1,648,961**	**0 MWh**						
		GRAND TOTAL CUSTOMER SOLUTIONS	**$ 91,774,870**	**339,491 MWh**	93.5%	100.9%	**$ 98,136,412**	**336,600 MWh**	**$ 13,652,557**	**5,204,500 Therms**	**101.9%**	**106.7%**	**$ 13,398,185**	**4,877,415 Therms**
		Total aMW Savings		**38.8 aMW**				**38.4 aMW**						
		PSE LIW Shareholder Funding[3]	$ 93,923						$ 182,587	n/a	92%	n/a	$ 300,000	n/a

Footnotes

1 Other Electric programs are separated because they are not included in cost effectiveness calculations.
2 Renewable Energy Education, Schedule 248, was formerly referred to as Small Scale Renewables.
3 LIW shareholder funding is not limited to the gas fuel type. Condition G(14) indicates that $300,000 in shareholder funding may be applied to electric or gas LIW. Figures are based on reported primary heating fuel type.

Exhibit 1: 2013 Expenditures and Savings

PUGET SOUND ENERGY, INC.
ELECTRIC & GAS RIDER CONSERVATION EXPENDITURES & SAVINGS
January - December 2013

EnergyEfficiency

Electric Schedule	Gas Schedule	Programs (Through December 2013)	Electric YTD Actual $ Spent	Electric YTD Actual MWh Svgs.	Electric Percentage % of $ Budget	Electric Percentage % of Svgs. TOTAL	Electric Budget $ BUDGET	Electric Budget MWh Svgs. Target	Gas YTD Actual $ Spent	Gas YTD Actual Therms Svgs.	Gas Percentage % of $ Budget	Gas Percentage %of Svgs. TOTAL	Gas Budget $ BUDGET	Gas Budget Therms Svgs. Target
		Please note that each indented amount sums to the colored heading above.												
		Residential												
E201	G201	Low Income Weatherization	$ 2,373,466	1,591	98%	132%	$ 2,425,000	1,201	$ 372,176	32,948	124%	156%	$ 301,000	21,179
E214	G214	Single Family Existing	$ 33,710,664	144,763	112%	115%	$ 30,183,000	125,947	$ 5,417,278	1,441,851	88%	75%	$ 6,127,000	1,920,051
		Residential Lighting	$ 17,520,974	103,551	134%	124%	$ 13,123,000	83,230	$ -		n/a		$ -	-
		Space heat	$ 3,275,154	8,085	109%	132%	$ 3,004,000	6,138	$ 1,612,308	571,028	68%	76%	$ 2,355,000	747,889
		Water heat	$ 500,414	874	85%	102%	$ 589,000	857	$ -	0	n/a	0%	$ -	-
		HomePrint	$ 960,033	1,796	52%	44%	$ 1,839,000	4,081		0	n/a	0%	$ -	-
		Home Appliances	$ 6,872,639	9,122	89%	74%	$ 7,752,000	12,405	$ -	9,560	n/a	25%	$ -	38,920
		Showerheads	$ 250,857	4,664	111%	133%	$ 226,000	3,496	$ 219,363	131,949	74%	74%	$ 296,000	179,280
		Weatherization Total	$ 3,466,305	9,902	68%	58%	$ 3,432,000	10,242	$ 2,604,223	422,735	89%	76%	$ 2,922,000	553,238
		Weatherization	$ 1,448,859	3,675	68%	58%	$ 2,134,000	6,351	$ 2,601,139	422,735	89%	76%	$ 2,922,000	553,238
		Mobile Home Duct Sealing	$ 1,169,806	3,137			$ 557,000	1,046	$ -	0				
		ARRA Weatherization	$ 847,640	3,090			$ 741,000	2,845	$ 3,085	0				
		Home Energy Reports	$ 864,288	6,769	396%	123%	$ 218,000	5,498	$ 344,235	251,283	346%	72%	$ 99,000	346,724
		Web-Enabled Thermostat							$ 637,148	55,296			$ 455,000	54,000
E215	G215	Single Family New Construction	$ 1,781,097	2,344	149%	211%	$ 1,199,000	1,112	$ 10,035	412				
E215		Energy Star Manufactured Homes	$ 17,845	113			$ 50,000	418		200				
E216		Single Family Fuel Conversion	$ 649,666	1,623	60%	61%	$ 1,084,000	2,649	$ -					
E217	G217	Multi Family Existing	$ 10,952,743	21,256	160%	127%	$ 6,862,000	16,747	$ 206,731	64,927	175%	366%	$ 118,000	17,736
E218	G218	Multi Family New Construction	$ 621,227	1,237	92%	130%	$ 674,000	955	$ 306,921	60,857	97%	130%	$ 317,000	46,713
E249	G249	Pilots[1]	$ -	0	0%		$ -	0	$ -	0			$ -	-
		Total Residential Programs	**$ 50,106,708**	**172,927 MWh**	**118%**	**116%**	**$ 42,477,000**	**149,029 MWh**	**$ 6,313,140**	**1,601,195**	**92%**	**80%**	**$ 6,863,000**	**2,005,679 Therms**
		Business												
E250	G250	Commercial Industrial Retrofit	$ 17,831,194	74,916	94%	105%	$ 18,986,000	71,375	$ 3,037,634	886,608	112%	182%	$ 2,702,000	487,100
E251	G251	Commercial Industrial New Construction	$ 1,366,570	3,059	93%	87%	$ 1,470,000	3,500	$ 299,462	56,384	48%	36%	$ 622,000	156,000
E253	G253	Resource Conservation Manager - RCM	$ 1,225,833	16,881	79%	90%	$ 1,558,000	18,750	$ 651,480	1,305,271	77%	218%	$ 851,000	600,000
E255		Small Business Lighting Rebate	$ 3,685,147	12,524	65%	78%	$ 5,640,000	16,040	$ -					
E258		Large Power User - Self Directed	$ 5,159,352	13,831	123%	106%	$ 4,189,000	13,000					$ -	-
E261	G261	Energy Efficient Technology Evaluation	$ -	n/a	0%		$ 31,000	n/a	$ -	n/a	0%		$ 28,000	n/a
E262	G262	Business Rebates	$ 8,319,853	46,526	125%	136%	$ 6,648,000	34,311	$ 660,920	2,689,003	84%	192%	$ 784,000	1,400,163
		Total Business Programs	**$ 37,587,949**	**167,737 MWh**	**98%**	**107%**	**$ 38,522,000**	**156,976 MWh**	**$ 4,649,496**	**4,937,266**	**93%**	**187%**	**$ 4,987,000**	**2,643,263 Therms**
		Regional												
E254		NW Energy Efficiency Alliance	$ 4,574,812	19,400	87%	100%	$ 5,261,000	19,414	$ -	n/a	n/a	n/a	n/a	n/a
E292		Generation, Transmission and Distribution	$ -	1,328		16%	$ -	8,078	$ -	n/a	n/a	n/a	n/a	n/a
		Total Regional Programs	**$ 4,574,812**	**20,728**	**87%**	**75%**	**$ 5,261,000**	**27,492**	$ -					
		EE Portfolio Support												
		Customer Engagement and Education	$ 1,092,488	n/a	72%	n/a	$ 1,518,000	n/a	$ 125,340	n/a	54%	n/a	$ 231,000	n/a
		Energy Advisors	$ 799,910	n/a	74%		$ 1,083,000	n/a	$ 61,161	n/a	38%	n/a	$ 162,000	n/a
		Events	$ 194,324	n/a	65%		$ 297,000	n/a	$ 48,047	n/a	99%	n/a	$ 48,000	n/a
		Brochures	$ 43,307	n/a	80%		$ 54,000	n/a	$ 7,776	n/a	95%	n/a	$ 8,000	n/a
		Education	$ 54,947	0	65%	n/a	$ 84,000	n/a	$ 8,355	n/a	62%	n/a	$ 13,000	n/a
		Customer Online Experience	$ 958,557	n/a	96%	n/a	$ 999,000	n/a	$ 198,813	n/a	209%	n/a	$ 150,000	n/a
		Customer Online Experience	$ 497,970	n/a	79%	n/a	$ 632,000	n/a	$ 77,265	n/a		n/a	$ 95,000	n/a
		Automated Benchmarking Support	$ 169,440	n/a			$ -		$ 71,530	n/a		n/a	$ -	n/a
		Market Integration	$ 291,147	n/a	79%	n/a	$ 367,000	n/a	$ 50,019	n/a	91%	n/a	$ 55,000	n/a
		Energy Efficient Communities	$ 264,034	n/a	69%	n/a	$ 381,000	n/a	$ 71,253	n/a	125%	n/a	$ 57,000	n/a
		Trade Ally Support	$ 30,955	n/a	50%	n/a	$ 62,000	n/a	$ -	n/a	0%	n/a	$ 25,000	n/a
		Marketing Research	$ 238,971	n/a	39%	n/a	$ 608,000	n/a	$ 31,883	n/a	35%	n/a	$ 91,000	n/a
		Total Portfolio Support	**$ 2,585,005**	**n/a**	**72%**	**n/a**	**$ 3,568,000**	**n/a**	**$ 427,289**	**n/a**	**77%**	**n/a**	**$ 554,000**	-
		EE Research & Compliance												
		Conservation Supply Curves	$ 166,347	n/a	65%	n/a	$ 255,000	n/a	$ 34,703	n/a	91%	n/a	$ 38,000	n/a
		Strategic Planning	$ 118,392	n/a	50%	n/a	$ 237,000	n/a	$ 15,867				$ 35,000	
		Program Evaluation	$ 2,212,512	n/a	102%	n/a	$ 2,159,000	n/a	$ 315,182	n/a	57%	n/a	$ 550,000	n/a
		Program Support	$ 216,337	n/a	48%	n/a	$ 454,000	n/a	$ 57,934	n/a	109%	n/a	$ 53,000	n/a
		Verification Team	$ 582,914	n/a	92%	n/a	$ 633,000	n/a	$ 105,810	n/a		n/a	$ 101,000	n/a
		Total Research & Compliance	**$ 3,296,502**	**n/a**	**88%**	**n/a**	**$ 3,738,000**	**n/a**	**$ 529,496**	**n/a**	**68%**		**$ 777,000**	-
		SUBTOTAL CUSTOMER SOLUTIONS - ENERGY EFFICIENCY	**$ 98,150,976** **104.9%**	**361,392 MWh** **108.4%**			**$ 93,566,000**	**333,497 MWh**	**$ 11,919,421** **90.4%**	**6,538,000 Therms** **140.6%**			**$ 13,181,000**	**4,649,000 Therms**
		Total aMW Savings		**41.3 aMW**				**38.1 aMW**						
		Other Electric Programs[2]												
E150		Net Metering	$ 369,302	n/a	80%	n/a	$ 461,000	n/a	n/a	n/a	n/a	n/a	n/a	n/a
E248		Renewable Energy Education	$ 50,876	n/a	42%	n/a	$ 120,000	0	n/a	n/a	n/a	n/a	n/a	n/a
E271		C/I Load Control	$ 44,598	n/a	18%	n/a	$ 244,000	n/a	n/a	n/a	n/a	n/a	n/a	n/a
E249A		Residential Demand Response Pilot	$ 166	n/a	2%	n/a	$ 10,000	n/a	n/a	n/a	n/a	n/a	n/a	n/a
		Total Other Electric Programs	**$ 464,941**	**0 MWh**	**56%**	**0%**	**$ 835,000**	**0 MWh**						
		GRAND TOTAL CUSTOMER SOLUTIONS	**$ 98,615,917**	**361,392 MWh**			**$ 94,401,000**	**333,497 MWh**	**$ 11,919,421**	**6,538,000 Therms**			**$ 13,181,000**	**4,649,000 Therms**
		Total aMW Savings	**104.5%**	**41.3 aMW** **108.4%**				**38.1 aMW**	**90.4%**	**140.6%**				
		PSE LIW Shareholder Funding[3]							$ 266,655	n/a	89%	n/a	$ 300,000	n/a

Footnotes

1 Neither the Residential no Business Energy Management Sectors pursued pilot measures in 2013.
2 Other Electric programs are separated because they are not included in cost-effectiveness calculations.
3 LIW Shareholder funding is not limted to th egas fuel type. Condition G(14) indicates that $300,000 in Shareholder funding may be applied to electric or gas LIW.

Exhibit 1 ELECTRIC & GAS SAVINGS AND RIDER CONSERVATION EXPENDITURES

EnergyEfficiency

January - December 2014

Blue type indicates a sub-total. Sub-totals sum to the figure above.

Index	Schedule (both electric and gas, unless otherwise noted)	Programs	Electric – YTD Actual – $ Spent	Electric – YTD Actual – MWh Svgs.	Electric – Percentage – % of $ Budget	Electric – Percentage – % of Svgs. TOTAL	Electric – Budget/Goal – $ BUDGET	Electric – Budget/Goal – MWh Svgs. Goal	Gas – YTD Actual – $ Spent	Gas – YTD Actual – Therms Svgs.	Gas – Percentage – % of $ Budget	Gas – Percentage – % of Svgs. TOTAL	Gas – Budget/Goal – $ BUDGET	Gas – Budget/Goal – Therms Svgs. Target
b		**Residential Energy Management**												
c	201	Low Income Weatherization	2,846,848	1,767	92%	112%	3,098,684	1,571	305,326	24,370	83%	89%	369,443	27,391
d														
e	214	Single Family Existing	34,745,718	122,126	110%	113%	31,488,589	108,552	6,020,622	1,639,779	114%	122%	5,270,608	1,343,061
f		*Residential Lighting*	18,354,571	78,615	124%	119%	14,840,761	66,120						
g		*Space heat*	3,687,729	8,811	90%	87%	4,109,360	10,132	1,548,363	528,266	95%	102%	1,632,744	519,800
h		*Water heat*	411,640	568	115%	104%	357,004	545	-	0	n/a	0%	-	-
i		*HomePrint*	1,741,341	2,676	79%	79%	2,194,053	3,400	-	0	n/a	0%	-	-
j		*Home Appliances*	6,527,288	8,986	106%	90%	6,138,400	10,011	n/a	25,048	n/a	313%	-	7,998
k		*Mobile Home Duct Sealing*	1,868,291	6,541	111%	182%	1,683,057	3,592	-	0				-
l		*Web-Enabled Thermostats*							37,659	0			168,800	-
m		*Showerheads*	375,258	4,302	57%	82%	653,030	5,255	289,759	145,777	120%	174%	242,100	83,803
n		*Weatherization + ARRA*	1,636,404	5,736	122%	159%	1,346,334	3,607	4,120,712	763,940			3,178,169	560,960
o		*Home Energy Reports*	143,195	5,892	86%	100%	166,590	5,890	24,129	176,748	49%	104%	48,795	170,500
p	215	Single Family New Construction	8,016	215			-	0	11,470	0				-
q	215	*Energy Star Manufactured Home*	900	15			-	0	150	200				
r	216	Fuel Conversion	655,950	1,741	84%	82%	779,020	1,893						
s	217	Multi Family Existing	13,170,704	24,524	144%	120%	9,143,960	20,446	527,181	113,684	69%	109%	759,929	104,272
t	218	Multi Family New Construction	505,546	871	85%	94%	594,747	926	248,324	36,566	75%	19%	332,111	191,833
u		**Total Residential Programs**	**51,933,683**	**151,259 MWh**	**115%**	**113%**	**45,105,000**	**133,388 MWh**	**7,113,073**	**1,814,599**	**106%**	**109%**	**6,732,091**	**1,666,557 Therms**
		Business Energy Management												
v	250	Commercial Industrial Retrofit	17,201,563	65,986	83%	92%	20,842,366	71,560	1,979,333	507,288	82%	134%	2,427,580	379,000
w	251	Commercial Industrial New Construction	1,456,770	4,287	94%	170%	1,556,056	2,525	201,621	44,440	121%	302%	167,036	14,700
x	253	Resource Conservation Management - RCM	1,570,077	14,081	106%	116%	1,478,661	12,150	556,956	893,389	97%	319%	576,060	280,000
y	255	Small Business Lighting Rebate (2013 YE rebates paid in Q1 & Q2 2014)	1,024,042	3,945	169%	197%	607,015	2,000						
z	258	Large Power User - Self Directed Program, 449 + Non-449	6,747,496	22,665	128%	148%	5,290,686	15,350						-
aa	261	Energy Efficient Technology Evaluation	5,042	n/a	2%		210,110	500	-	n/a	0%		20,000	n/a
ab	262	Commercial Rebates	7,872,398	37,865	118%	141%	6,653,602	26,877	741,036	316,469	101%	41%	734,434	769,600
ac		**Total Business Programs**	**35,877,388**	**148,830 MWh**	**98%**	**114%**	**36,638,496**	**130,962 MWh**	**3,478,945**	**1,761,586**	**89%**	**122%**	**3,925,110**	**1,443,300 Therms**
		Pilots												
ad	249	Residential Pilots - Individual Energy Reports	387,685	26,759	32%		1,207,400	26,760 MWh	294,914	769,956			248,630	770,000 Therms
ae	249	Business Pilots - Individual Energy Reports	416,850	0	114%		365,059	0 MWh	-	-			-	
af		**Total Pilots**	**804,535**	**26,759 MWh**	**51%**		**1,572,459**	**26,760 MWh**	**294,914**	**769,956**	**119%**		**248,630**	**770,000 Therms**
		Regional Efficiency Programs												
ag	254	NW Energy Efficiency Alliance	4,447,503	50,195	85%	100%	5,260,640	50,195						
ah		NW Gas Market Transformation Collaborative							151,968	n/a				
ai	292	Electric Generation, Transmission and Distribution	-	1,496		48%	-	3,100						
aj		**Total Regional Programs**	**4,447,503**	**51,691 MWh**	**85%**	**97%**	**5,260,640**	**53,295**	**151,968**					
		Energy Efficiency Portfolio Support												
ak		Customer Engagement and Education	1,019,594	n/a	66%	n/a	1,552,503	n/a	150,876	n/a	64%	n/a	236,922	n/a
al		*Energy Advisors*	596,628	n/a	55%		1,094,604	n/a	68,805	n/a	42%	n/a	164,165	n/a
am		*Events*	330,277	n/a	96%		343,308	n/a	64,140	n/a	117%	n/a	54,783	n/a
an		*Brochures, non program-specific*	10,926	n/a	20%		54,250	n/a	1,226	n/a	15%	n/a	8,169	n/a
ao	202	*Education*	81,762	0	136%	n/a	60,341	n/a	16,705	n/a	170%	n/a	9,805	n/a
ap		Web Experience	882,264				955,427		152,756	n/a	175%	n/a	165,501	
aq		Customer Online Experience	558,402	n/a	96%	n/a	584,205	n/a	80,845				87,295	n/a
ar		Market Integration	257,891	n/a	89%	n/a	289,773	n/a	50,909	n/a	118%	n/a	43,299	n/a
as		MyData (Automated Benchmarking System)	65,971				81,449		21,002				34,907	
at		Rebate Processing *(formerly assessed costs--will be active 1/2015)*					(Not budgeted in original 2014 Exhibit 1)						(Not budgeted in original 2014 Exhibit 1)	n/a
au		Data and Systems Services *(formerly assessed costs--added 5/2014)*	554,907				(Not budgeted in original 2014 Exhibit 1)	n/a	79,730				(Not budgeted in original 2014 Exhibit 1)	n/a
av		Energy Efficient Communities	328,297	n/a	41%	n/a	796,492	n/a	79,302	n/a	41%	n/a	195,613	n/a
aw		Trade Ally Support	56,347	n/a	104%	n/a	54,183	n/a	12,324	n/a	103%	n/a	11,952	n/a
ax		**Total Portfolio Support**	**2,841,408**	**n/a**	**85%**	**n/a**	**3,358,605**	**n/a**	**474,988**	**n/a**	**78%**	**n/a**	**609,988**	-
		Energy Efficiency Research & Compliance												
ay		Conservation Supply Curves	419,210	n/a	106%	n/a	396,319	n/a	62,776	n/a	106%	n/a	59,221	n/a
az		Strategic Planning	209,362	n/a	74%	n/a	283,007	n/a	29,195				42,285	
ba		Market Research	124,635				233,917		25,030				35,730	
bb		Program Evaluation	1,107,531	n/a	84%	n/a	1,320,727	n/a	152,787	n/a	114%	n/a	134,378	n/a
bc		Biennial Electric Conservation Acquisition Review	17,761				175,000							
bd		Verification Team	451,303	n/a	69%	n/a	657,008	n/a	68,780	n/a	71%	n/a	97,408	n/a
be		Program Support	270,451	n/a	64%	n/a	419,597	n/a	36,007	n/a		n/a	42,301	n/a
bf														
bg		**Total Research & Compliance**	**2,600,253**	**n/a**	**75%**	**n/a**	**3,485,575**	**n/a**	**374,576**	**n/a**	**91%**		**411,323**	-
bh		**SUBTOTAL CUSTOMER SOLUTIONS - ENERGY EFFICIENCY**	**98,504,770**	**378,539 MWh**			**95,420,775**	**344,405 MWh**	**11,888,463**	**4,346,141 Therms**			**11,927,142**	**3,879,857 Therms**
bi			**103%**	**110%**					**100%**	**112%**				
bk		**Total aMW Savings**		**43.2 aMW**				**39.3 aMW**						
		Other Electric Programs [1]												
bl	150	Net Metering	632,391	n/a	158%	n/a	399,763	n/a						
bn	248	Renewable Energy Education [2]	2,794	n/a		n/a	-	0						
bo	195	Electric Vehicle Charger Incentive	195,200											
bp	271	C/I Load Control	-	n/a		n/a	-	n/a						
bq	249A	Residential Demand Response Pilot	-	n/a		n/a	-	n/a						
br		**Total Other Electric Programs**	**830,385**	**0 MWh**	**208%**	**0%**	**399,763**	**0 MWh**						
bt		**GRAND TOTAL CUSTOMER SOLUTIONS**	**99,335,154**	**378,539 MWh**			**95,820,538**	**344,405 MWh**	**11,888,463**	**4,346,141 Therms**			**11,927,142**	**3,879,857 Therms**
bu		**Total aMW Savings**		**43.2 aMW**				**39.3 aMW**						
bv			**104%**	**110%**					**100%**	**112%**				
bw		PSE LIW Shareholder Funding [3]							379,005	n/a	95%	n/a	400,000	n/a

These are now combined

Some index lettering is purposely omitted.

Footnotes

1. Other Electric programs are separated because they are not included in cost effectiveness calculations.
2. Renewable Energy Education, Schedule 248, was formerly referred to as Small Scale Renewables.
3. LIW shareholder funding is not limited to the gas fuel type. Condition G(14) indicates that $300,000 in shareholder funding may be applied to electric or gas LIW. The decoupling Order in Docket Nos. UE-121697 & UG-121705 require that an additional $100,000 in shareholder funding be made avaiable to low-income agencies.

Exhibit 1

2015-specific PSE Conservation Rider Savings Goals and Budgets

Last revised: 12/15/15 10:33 AM

Titles are hyperlinks to 2015 Sector Views

Ref #	Schedule Nos. (Unless otherwise noted, applies to both electric and gas)	Program Name	MWh Savings	Electric Rider Budget	Therm Savings	Gas Rider Budget	Total Tariff Budget
		(All indented program or activity names are color-coded and comprise the totals of the above program or activity grouping. In some cases, there are sub-activities within another sub-grouping.)					
		Residential Energy Management					
a	201	Low Income Weatherization	1,571	$ 3,318,140	18,815	268,098	$ 3,586,237
b	214	Single Family Existing	101,368	$ 31,570,261	1,195,517	$ 5,522,571	$ 37,092,832
c		*Residential lighting*	*66,609*	*$ 15,379,407*			*$ 15,379,407*
d		*Space heat*	*7,842*	*$ 4,061,640*	*531,650*	*$ 1,595,778*	*$ 5,657,418*
e		*Water heat*	*635*	*$ 400,630*	*0*	*$ -*	*$ 400,630*
f		*HomePrint*	*3,009*	*$ 1,811,236*	*0*	*$ -*	*$ 1,811,236*
g		*Home Appliances*	*11,386*	*$ 6,297,053*	*32,736*		*$ 6,297,053*
h		*Mobile Home Duct Sealing*	*4,666*	*$ 1,665,636*	*0*	*$ -*	*$ 1,665,636*
i		*Web-Enabled Thermostats*			*54,000*	*$ 323,443*	*$ 323,443*
j		*Showerheads*	*4,139*	*$ 574,710*	*145,116*	*$ 387,115*	*$ 961,824*
k		*Weatherization*	*2,610*	*$ 1,227,724*	*432,015*	*$ 3,171,545*	*$ 4,399,269*
l		*Home Energy Reports*	*473*	*$ 152,226*	*0*	*$ 44,691*	*$ 196,916*
m	215 & 218	Residential New Construction	1,057	$ 486,591	147,072	$ 657,848	$ 1,144,439
n	216	Fuel Conversion	2,063	$ 785,783			$ 785,783
o	217	Multi Family Existing	25,862	$ 11,513,537	107,542	$ 499,044	$ 12,012,581
p		**Total, Residential Programs**	**131,921**	**$ 47,674,312**	**1,468,945**	**$ 6,947,561**	**$ 54,621,873**
		Business Energy Management					
q	250	Commercial / Industrial Retrofit	62,260	$ 19,421,153	381,000	$ 2,044,680	$ 21,465,833
r	251	Commercial/Industrial New Construction	9,350	$ 2,987,974	150,000	$ 606,236	$ 3,594,210
s	253	Resource Conservation Manager	16,350	$ 2,744,361	500,000	$ 636,260	$ 3,380,621
t	E258	Large Power User - Self Directed Program	1,700	$ 1,667,723			$ 1,667,723
u	261	Energy Efficient Technology Evaluation	500	$ 210,710		$ 20,000	$ 230,710
v	262	Commercial Rebates	21,967	$ 5,641,008	580,881	$ 698,839	$ 6,339,847
w		**Subtotal, Business Programs**	**112,126**	**$ 32,672,929**	**1,611,881**	**$ 4,006,015**	**$ 36,678,944**
		Pilots					
x	249	Residential Pilots - Individual Energy Reports	3,219	$ 1,127,007	0	$ 233,902	$ 1,360,909
y	249	Business Pilots - Individual Energy Reports	5,000	$ 140,704	0	$ -	$ 140,704
z		**Subtotal, Pilots**	**8,219**	**$ 1,267,712**	**0**	**$ 233,902**	**$ 1,501,613**
		Regional Efficiency Programs					
aa	E254	NW Energy Efficiency Alliance	22,338	$ 4,771,922	0	$ 738,000	$ 5,509,922
ab	E292	Generation, Transmission and Distribution	3,000	$ -			$ -
ac		**Subtotal, Regional Programs**	**25,338**	**$ 4,771,922**		**$ 738,000**	**$ 5,509,922**
		Energy Efficiency Portfolio Support					
ad		Customer Engagement and Education		$ 1,752,121		$ 264,482	$ 2,016,603
ae		*Energy Advisors*		*$ 1,060,385*		*$ 158,556*	*$ 1,218,941*
af		*Events*		*$ 530,379*		*$ 81,547*	*$ 611,926*
ag		*Brochures, non program-specific*		*$ 80,222*		*$ 12,752*	*$ 92,974*
ah	202	*Education*		*$ 81,135*		*$ 11,627*	*$ 92,762*
ai		Web Experience		$ 928,838		$ 155,097	$ 1,083,935
aj		Customer Online Experience		$ 562,455		$ 84,045	$ 646,500
ak		*Web Development*		*$ -*		*$ -*	*$ -*
al		*Web content, maintenance + analytics*		*$ 104,400*		*$ 15,600*	*$ 120,000*
am		*Online customer tools*		*$ 435,000*		*$ 65,000*	*$ 500,000*
an		*E-news*		*$ 10,005*		*$ 1,495*	*$ 11,500*
ao		*Miscellaneous applications*		*$ 13,050*		*$ 1,950*	*$ 15,000*
ap		Market Integration		$ 298,797		$ 44,648	$ 343,445
aq		Automated Benchmarking System		$ 67,586		$ 26,404	$ 93,990
ar		Programs Support		$ 1,279,676		$ 171,099	$ 1,450,775
as		Rebates Processing		$ 740,193		$ 110,214	$ 850,407
at		Energy Efficient Communities		$ 814,516		$ 200,854	$ 1,015,370
au		Trade Ally Support		$ 60,333		$ 12,792	$ 73,125
av		**Subtotal, Portfolio Support**		**$ 5,575,677**		**$ 914,537**	**$ 6,490,214**
		Energy Efficiency Research & Compliance					
aw		Conservation Supply Curves		$ 196,761		$ 29,397	$ 226,158
ax		Strategic Planning		$ 158,393		$ 23,663	$ 182,056
ay		Market Research		$ 316,165		$ 47,246	$ 363,411
az		Verification Team		$ 457,749		$ 68,399	$ 526,148
ba		Program Evaluation		$ 2,567,563		$ 313,714	$ 2,881,277
bb		Biennial Electric Conservation Acquisition Review		$ 110,000			$ 110,000
bc		**Subtotal, Research & Compliance**	**0**	**$ 3,806,632**		**$ 482,420**	**$ 4,289,051**
bd	**Total MWh, Efficiency Programs Included in CE Calculations**		**277,605**	**$ 95,769,183**	**3,080,826**	**$ 13,322,435**	**$ 109,091,617**
		Other Electric Programs					
be	E150	Net Metering		$ 760,196			$ 760,196
bf	E195	Electric Vehicle Charger Incentive		$ 2,878,146			$ 2,878,146
bg		**Subtotal, Other Electric Programs**		**$ 3,638,342**		**$ -**	**$ 3,638,342**
bh		**GRAND TOTAL All Programs**	**31.7 aMW**	**$ 99,407,525**	**3,080,826**	**$ 13,322,435**	**$ 112,729,960**
bi		**Electric Total, less NEEA**	**255,267 MWh** **29.1 aMW**	**$ 94,635,604**			
bj		**Electric Total, less (NEEA + Pilots)**	**247,048 MWh** **28.2 aMW**	**$ 93,367,892**			
bk		Blue cells = use for 10% "info-only" calculation:		7.1%		8.6%	
		Add up all blue cells and divide by "Total, Efficiency Programs Included in CE Calculations" line.					
		HER-legacy program costs excluded from "info-only" calculation because savings will be measured.					
bl		Purple cells = use to indicate a reasonable amt. spent on EM&V:		3.9%		3.5%	
		Add up the sum of "Program Evaluation" + "Verification" pink cells and divide by the Residential + Business pink cells.					

April, 2015: Please note that the Rebates Processing total budget amount (circled above in red: $740,193) is revised from the originally-filed (Nov. 26, 2014) Exhibit 1 total of $654,327. Due to a formula error in the "Overhead" table on the Rebates Processing detail page, (page # 81 of the PDF "UE-132043 PSE Volume 2_2015 Exhibits 1 thru 11) the correctly-calculated overhead amount of $293,058.40 was multiplied by the overhead rate of 70.7% *again*. The resulting amount noted in the originally-filed Exhibit 1 ($207,193.29) was incorrect by $85,866.11. The value noted in the blue "Overhead Total" in the Rebates Processing detail page now accurately reflects the anticipated labor overhead for Rebates Processing in 2015.

Exhibit 1

2016-specific PSE Conservation Rider Savings Goals and Budgets

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Last revised: 9/16/16 2:46 PM

Return to Two-year view

Titles are hyperlinks to 2016 Sector Views

Ref #	Schedule Nos. (Unless otherwise noted, applies to both electric and gas)	Program Name	MWh Savings	Electric Rider Budget	Therm Savings	Gas Tracker Budget	Total Tariff Budget
		(All indented program or activity names are color-coded and comprise the totals of the above program or activity grouping. In some cases, there are sub-activities within another sub-grouping.)					
		Residential Energy Management					
a	201	Low Income Weatherization	1,560	$ 3,386,625	18,641	$ 283,479	$ 3,670,104
b	214	Single Family Existing	110,402	$ 30,687,840	1,684,420	$ 5,873,062	$ 36,560,902
c		*Residential lighting*	*71,294*	*$ 14,215,007*			*$ 14,215,007*
d		*Space heat*	*7,284*	*$ 4,107,422*	*645,705*	*$ 2,420,721*	*$ 6,528,143*
e		*Water heat*	*571*	*$ 408,509*	*-*	*$ -*	*$ 408,509*
f		*Home Energy Assessment*	*3,423*	*$ 2,192,477*	*-*	*$ -*	*$ 2,192,477*
g		*Home Appliances*	*10,291*	*$ 5,792,811*	*46,930*	*$ 16,650*	*$ 5,809,461*
h		*Mobile Home Duct Sealing*	*2,972*	*$ 1,456,037*	*-*	*$ -*	*$ 1,456,037*
i		*Web-Enabled Thermostats*	*848*	*$ 355,654*	*34,000*	*$ 202,825*	*$ 558,478*
j		*Showerheads*	*4,776*	*$ 652,129*	*326,631*	*$ 529,322*	*$ 1,181,451*
k		*Weatherization*	*3,221*	*$ 1,278,574*	*391,188*	*$ 2,637,367*	*$ 3,915,941*
l		*Home Energy Reports*	*5,722*	*$ 229,221*	*239,967*	*$ 66,178*	*$ 295,398*
m	215 & 218	Residential New Construction	2,000	$ 792,219	52,630	$ 228,332	$ 1,020,551
n	216	Fuel Conversion	1,897	$ 833,282			$ 833,282
o	217	Multi Family Existing	17,190	$ 9,776,000	102,946	$ 974,655	$ 10,750,655
p		**Total, Residential Programs**	**133,049**	**$ 45,475,966**	**1,858,637**	**$ 7,359,528**	**$ 52,835,494**
		Business Energy Management					
q	250	Commercial / Industrial Retrofit	67,800	$ 18,857,083	355,000	$ 1,857,369	$ 20,714,452
r	251	Commercial/Industrial New Construction	10,108	$ 2,642,725	157,500	$ 630,984	$ 3,273,709
s	253	Resource Conservation Management	14,250	$ 2,578,518	500,000	$ 498,900	$ 3,077,418
t	E258	Large Power User - Self Directed Program	13,146	$ 4,968,142			$ 4,968,142
u	261	Energy Efficient Technology Evaluation	-	$ -	-	$ -	$ -
v	262	Commercial Rebates	28,265	$ 6,883,867	661,796	$ 1,761,060	$ 8,644,927
w		**Subtotal, Business Programs**	**133,570**	**$ 35,930,334**	**1,674,296**	**$ 4,748,313**	**$ 40,678,647**
		Pilots					
x	249	Residential Pilots - Individual Energy Reports	17,347	$ 976,899	430,529	$ 181,029	$ 1,157,928
y	249	Business Pilots - Individual Energy Reports	-	$ -	-	$ -	$ -
z		**Subtotal, Pilots**	**17,347**	**$ 976,899**	**430,529**	**$ 181,029**	**$ 1,157,928**
		Regional Efficiency Programs					
aa	E254	NW Energy Efficiency Alliance	8,760	$ 5,200,000			$ 5,200,000
ab		NEEA Natural Gas Market Transformation			-	$ 1,086,677	$ 1,086,677
ac		Generation, Transmission and Distribution	1,781	$ -			$ -
ad		**Subtotal, Regional Programs**	**10,541**	**$ 5,200,000**	**-**	**$ 1,086,677**	**$ 6,286,677**
		Energy Efficiency Portfolio Support					
ae		Customer Engagement and Education		$ 1,893,684		$ 214,543	$ 2,108,227
af		*Energy Advisors*		*$ 1,127,545*		*$ 83,937*	*$ 1,211,482*
ag		*Events*		*$ 668,909*		*$ 115,416*	*$ 784,325*
ah		*Brochures, non program-specific*		*$ 88,430*		*$ 14,215*	*$ 102,645*
ai	*202*	*Education*		*$ 8,800*		*$ 975*	*$ 9,775*
aj		Electronic Media Tools & Marketing		$ 1,036,967		$ 158,916	$ 1,195,883
ak		*Customer Digital Experience*		$ 588,990		$ 88,010	$ 677,000
al		*Market Integration*		$ 323,347		$ 51,223	$ 374,570
am		*Automated Benchmarking System*		$ 124,630		$ 19,683	$ 144,313
an		Rebates Processing		$ 660,029		$ 98,625	$ 758,655
ao		Programs Support		$ 311,175		$ 45,210	$ 356,384
ap		Data and Systems Services		$ 1,196,032		$ 178,924	$ 1,374,956
aq		Energy Efficient Communities		$ 899,299		$ 130,495	$ 1,029,794
ar		Trade Ally Support		$ 117,661		$ 21,015	$ 138,676
as		Contractor Alliance Network *(net of revenue + cost)*		$ (18,116)		$ (18,096)	$ (36,212)
at		**Subtotal, Portfolio Support**		**$ 6,096,731**		**$ 829,632**	**$ 6,926,364**
		Energy Efficiency Research & Compliance					
au		Conservation Supply Curves		$ 440,752		$ 65,860	$ 506,612
av		Strategic Planning		$ 140,934		$ 21,059	$ 161,993
aw		Market Research		$ 281,703		$ 42,094	$ 323,796
ax		Program Evaluation		$ 1,810,699		$ 270,564	$ 2,081,263
ay		Biennial Electric Conservation Acquisition Review		$ 70,000			$ 70,000
az		Verification Team		$ 410,403		$ 108,960	$ 519,363
ba		**Subtotal, Research & Compliance**		**$ 3,154,491**		**$ 508,537**	**$ 3,663,027**
bb	**Total MWh, Efficiency Programs Included in CE Calculations**		**294,507**	**$ 96,834,421**	**3,963,462 therms**	**$ 14,713,716**	**$ 111,548,137**
		Other Electric Programs					
bc	E150	Net Metering		$ 911,904			$ 911,904
bd	E195	Electric Vehicle Charger Incentive		$ 853,682			$ 853,682
be		**Subtotal, Other Electric Programs**		**$ 1,765,586**			**$ 1,765,586**
bf	Go to Building the Electric Target Page	**GRAND TOTAL All Programs**	**294,507 MWh 33.6 aMW**	**$ 98,600,007**	**3,963,462 therms**	**$ 14,713,716**	**$ 113,313,723**
bg	Go to Building the GasTarget Page	**Total, All Programs, less (NEEA + Energy Report Pilots)**	**268,400 MWh 30.6 aMW**		**3,532,933 therms**		
bh		Blue cells = use for 10% "info-only" calculation:		7.3%		6.9%	
		Add up all blue cells and divide by "Total, Efficiency Programs Included in CE Calculations" line.					
		HER program costs excluded from "info-only" calculation because savings will be measured.					
bi		Purple cells = use to indicate a reasonable amt. spent on EM&V:		2.8%		3.1%	
		Add up the sum of "Program Evaluation" + "Verification" pink cells and divide by the Residential + Business pink cells.					

XI. Reference Appendix II – Summary of Decoupling Deferrals

Tables in this Appendix summarize yearly deferral amounts (dollars), by deferral group, for the first three decoupling years:

- July 1, 2013 through June 30, 2014
- July 1, 2014 through June 30, 2015
- July 1, 2015 through June 30, 2016

Puget Sound Energy
Summary of Decoupling Deferrals by Group
July 2013 - June 2014

	Electric Residential	Electric Non-Residential (1)	Electric Schedule 26	Electric Schedule 31	Total Electric	Gas Residential	Gas Non-Residential (2)	Total Gas	Total Electric & Gas
July-13	$ (259,574)	$ (798,799)			$ (1,058,373)	$ 948,190	$ (199,466)	$ 748,724	$ (309,649)
August-13	$ (900,618)	$ (691,552)			$ (1,592,170)	$ 361,191	$ 839,910	$ 1,201,101	$ (391,069)
September-13	$ (644,010)	$ 148,491			$ (495,519)	$ 276,033	$ (132,528)	$ 143,505	$ (352,014)
October-13	$ (4,810,446)	$ (785,102)			$ (5,595,548)	$ (2,878,075)	$ (103,484)	$ (2,981,560)	$ (8,577,108)
November-13	$ (2,913,623)	$ 1,252,815			$ (1,660,808)	$ 273,016	$ 700,771	$ 973,787	$ (687,021)
December-13	$ (4,474,000)	$ (112,556)			$ (4,586,556)	$ (4,432,049)	$ (818,783)	$ (5,250,832)	$ (9,837,388)
January-14	$ 1,884,861	$ 604,600	$ 441,504	$ 359,690	$ 3,290,655	$ (431,949)	$ 1,096,276	$ 664,327	$ 3,954,982
February-14	$ 2,599,014	$ 1,300,880	$ 178,408	$ 395,325	$ 4,473,628	$ (1,007,277)	$ (817,310)	$ (1,824,588)	$ 2,649,041
March-14	$ 3,064,271	$ 1,723,236	$ (121,554)	$ (376,581)	$ 4,289,371	$ 1,783,807	$ 958,170	$ 2,741,977	$ 7,031,348
April-14	$ 4,708,449	$ 1,386,757	$ 11,061	$ (148,230)	$ 5,958,037	$ 2,446,407	$ 784,943	$ 3,231,350	$ 9,189,387
May-14	$ 1,774,495	$ (158,834)	$ 195,091	$ 300,183	$ 2,110,935	$ 2,782,447	$ 45,210	$ 2,827,658	$ 4,938,592
June-14	$ 1,824,668	$ 629,118	$ (206,458)	$ (119,838)	$ 2,127,490	$ 956,204	$ 682,910	$ 1,639,115	$ 3,766,604
Total	$ 1,853,486	$ 4,499,054	$ 498,052	$ 410,549	$ 7,261,141	$ 1,077,945	$ 3,036,618	$ 4,114,564	$ 11,375,704

Note 1: Deferral amounts above do not include revenue sensitive items.
Note 2: Deferral amounts above are restated for the Errata Adjustment that was approved by the Commission on April 22, 2014 (Order 14, Dockets UE-121697/UG-121705).

(1) Rate Schedules 26&31 were included in this group until December 31, 2014. Per Settlement Agreement they were split into their own decoupling groups effective January 1, 2014.
(2) Rate Schedules 85,85T,87&87T were included in this group until December 31, 2014. Per Settlement Agreement these schedules went on the rate plan effective January 1, 2014.

Puget Sound Energy
Summary of Decoupling Deferrals by Group
July 2014 - June 2015

	Electric Residential	Electric Non-Residential (1)	Electric Schedule 26	Electric Schedule 31	Total Electric	Gas Residential	Gas Non-Residential (2)	Total Gas	Total Electric & Gas
July-14	$ (1,216,630)	$ (1,284,018)	$ (228,340)	$ (21,835)	$ (2,750,823)	$ 988,170	$ 273,213	$ 1,261,383	$ (1,489,440)
August-14	$ (1,380,053)	$ (559,756)	$ (16,747)	$ 365,286	$ (1,591,269)	$ 915,535	$ 48,058	$ 963,593	$ (627,677)
September-14	$ 225,113	$ 764,976	$ 153,919	$ 6,471	$ 1,150,479	$ 1,950,525	$ 359,037	$ 2,309,561	$ 3,460,040
October-14	$ (1,664,689)	$ 198,463	$ 253,483	$ 101,299	$ (1,111,444)	$ 5,476,407	$ 1,299,857	$ 6,776,264	$ 5,664,820
November-14	$ (3,772,094)	$ 432,887	$ 295,380	$ 439,785	$ (2,604,043)	$ 930,627	$ (393,675)	$ 536,952	$ (2,067,091)
December-14	$ (422,196)	$ 1,089,953	$ 233,164	$ 179,240	$ 1,080,161	$ 4,370,775	$ 1,398,565	$ 5,769,341	$ 6,849,502
January-15	$ 3,647,972	$ 1,486,935	$ (229,809)	$ 83,597	$ 4,988,694	$ 5,948,277	$ 1,519,117	$ 7,467,394	$ 12,456,089
February-15	$ 8,665,193	$ 2,131,950	$ (68,495)	$ (105,452)	$ 10,623,197	$ 10,584,348	$ 2,843,848	$ 13,428,196	$ 24,051,393
March-15	$ 5,129,865	$ 1,731,114	$ 272,458	$ 275,695	$ 7,409,132	$ 7,233,606	$ 1,677,300	$ 8,910,907	$ 16,320,039
April-15	$ 4,187,841	$ 1,045,890	$ 187,610	$ 118,108	$ 5,539,449	$ 2,831,985	$ 513,913	$ 3,345,898	$ 8,885,347
May-15	$ 2,235,291	$ (61,743)	$ 221,348	$ 365,259	$ 2,760,155	$ 3,174,805	$ 691,963	$ 3,866,768	$ 6,626,923
June-15	$ 1,066,795	$ (198,529)	$ (82,677)	$ 103,522	$ 889,110	$ 2,412,067	$ 728,139	$ 3,140,206	$ 4,029,316
Total	$ 16,702,407	$ 6,778,121	$ 991,294	$ 1,910,977	$ 26,382,799	$ 46,817,127	$ 10,959,335	$ 57,776,462	$ 84,159,262

Note 1: Deferral amounts above do not include revenue sensitive items.

Note 2: Deferral amounts above are restated for the Errata Adjustment that was approved by the Commission on April 22, 2015 (Order 14, Dockets UE-121697/UG-121705).

(1) Rate Schedules 26&31 were included in this group until December 31, 2013. Per Settlement Agreement they were split into their own decoupling groups effective January 1, 2014.

(2) Rate Schedules 85,85T,87&87T were included in this group until December 31, 2013. Per Settlement Agreement these schedules went on the rate plan effective January 1, 2014.

Puget Sound Energy
Summary of Decoupling Deferrals by Group
July 2015 - June 2016

	Electric Residential	Electric Non-Residential (1)	Electric Schedule 26	Electric Schedule 31	Total Electric	Gas Residential	Gas Non-Residential (2)	Total Gas	Total Electric & Gas
July-15	$ (1,288,010)	$ (1,616,215)	$ (486,816)	$ (504,609)	$ (3,895,650)	$ 1,754,719	$ 647,357	$ 2,402,077	$ (1,493,574)
August-15	$ (1,329,890)	$ (220,775)	$ 19,711	$ 21,948	$ (1,509,007)	$ 1,023,399	$ 259,386	$ 1,282,785	$ (226,222)
September-15	$ 492,133	$ 1,331,649	$ (57,384)	$ (138,360)	$ 1,628,039	$ 905,681	$ 279,326	$ 1,185,007	$ 2,813,046
October-15	$ (1,665,894)	$ 242,069	$ 311,807	$ 50,218	$ (1,061,800)	$ 5,236,892	$ 1,244,400	$ 6,481,291	$ 5,419,491
November-15	$ (4,048,420)	$ (326,594)	$ 452,820	$ 368,035	$ (3,554,159)	$ 435,956	$ 717,740	$ 1,153,696	$ (2,400,463)
December-15	$ (1,377,276)	$ 755,079	$ 67,240	$ (320,711)	$ (875,667)	$ 2,203,969	$ (668,084)	$ 1,535,884	$ 660,217
January-16	$ 2,042,741	$ 638,327	$ 352,554	$ 313,234	$ 3,346,856	$ 2,518,253	$ 1,488,380	$ 4,006,633	$ 7,353,490
February-16	$ 7,002,528	$ 1,314,181	$ (62,731)	$ (85,711)	$ 8,168,268	$ 8,244,220	$ 2,573,371	$ 10,817,592	$ 18,985,860
March-16	$ 4,478,543	$ 2,126,884	$ 373,976	$ 198,867	$ 7,178,270	$ 4,474,424	$ 752,220	$ 5,226,644	$ 12,404,914
April-16	$ 7,488,522	$ 2,544,971	$ 71,692	$ 140,790	$ 10,245,975	$ 7,616,906	$ 1,950,533	$ 9,567,439	$ 19,813,413
May-16	$ 1,946,886	$ 251,224	$ 116,463	$ 52,224	$ 2,366,797	$ 3,327,294	$ 1,280,322	$ 4,607,616	$ 6,974,413
June-16	$ 2,712,315	$ 901,032	$ (263,465)	$ (179,653)	$ 3,170,229	$ 1,552,959	$ 251,221	$ 1,804,181	$ 4,974,409
Total	$ 16,454,176	$ 7,941,834	$ 895,867	$ (83,728)	$ 25,208,149	$ 39,294,672	$ 10,776,173	$ 50,070,845	$ 75,278,994

Note 1: Deferral amounts above do not include revenue sensitive items.

(1) Rate Schedules 26&31 were included in this group until December 31, 2014. Per Settlement Agreement they were split into their own decoupling groups effective January 1, 2014.
(2) Rate Schedules 85,85T,87&87T were included in this group until December 31, 2014. Per Settlement Agreement these schedules went on the rate plan effective January 1, 2014.

XII. Reference Appendix III – A Change in the Weather

Weather has been a factor throughout several sections of this study, in particular as a warming cycle and as at least one extreme weather event. Weather is constantly changing and analysis of weather can be complicated, depending on the degree of specificity required. We start from the fact that the colder it is outside; the more energy it takes to keep a residential building at a desired temperature. If we wanted to be exact, we would have to look at individual buildings and their characteristics. Ideally, we could model all the buildings and then aggregate results for a more precise result.

Heating Degree Days

However, we do not need a precise result; we can make do with an indicator. For use as an indicator, the electric utility industry has found generic heating degree days (HDD) to be a sufficiently useful metric (see Heating Degree Days text box). Puget Sound Energy uses the airport weather station at SEATAC (weather station ID: KSEA; latitude 47.44359 degrees North latitude and-122.3028 degrees East longitude).

Different balance points can be used, but the generic HDD balance point is 65 degrees Fahrenheit. Traditionally, degree days are calculated as a thirty-year average. In theory, this average of thirty years gives baseline, or normal, weather. Heating Degree Days occur on days when outside temperature is below the balance point. HDDs are additive over a particular time period. HDDs are a basic analytic tool used in this study.

> **Heating Degree Days**
>
> *Heating degree days*", or "*HDD*", are a measure of how much (in degrees), and for how long (in days), outside air temperature was *lower* than a specific "*base temperature*" (or "*balance point*").
>
> See: BizEE Degree Days, Weather Data for Energy Professionals (http://www.degreedays.net)/.

Climate Trend

What about the effect of climate change? The difference between weather and climate is a matter of time perspective. Weather is short term; climate change is a trend in weather over long periods of time. We are experiencing a long-term trend of climate warming.

Here, again, we develop an indicator of the climate trend based on the HDD indicator, climate projections and regression analysis. The analysis began with data provided by PSE in response to DR 30.29 for 2001-2015. To secure a more adequate number of years for conducting a regression analysis, SEATAC HDD data which we have for use in a separate project on climate warming and perceptions of time was employed. This contains SEATAC airport weather station data beginning in 1948. The SEATAC data is then joined to year by year HDD projections to 2100. These climate projections were developed by Dr. Katherine Hegewisch, Postdoctoral Fellow, Applied Climate Lab, University of Idaho, who is working in the University of Idaho MACA project to downscale climate information to local areas in the Pacific Northwest. The projections are based on 20 climate models and the high emissions scenario. We use a yearly simple average of the results of the 20 climate models to develop a single data point for each year included in the analysis. We then run the regression analysis using SPSS 24 which derives the equation of the regression line. Finally, we use the regression equation to find the year in which the number of HDD goes to zero, considering only the linear trend.

In Figure XII.1, climate warming is expressed as the gradual decline of yearly heating degree days, from about 5,882 HDD in 1948 to about 3,961 in 2014 to about 2,443 HDD in 2099 and continuing downwards.

However, over the three years of decoupling, the effect size of the long-term climate trend is too small to be of importance in influencing decoupling results. The increase in temperature is happening. But within a three-year time horizon the piece of the long-term trend experienced is too small and its effect is too weak to be directly relevant in this study. This figure shows the climate warming trend at the Seattle-Tacoma airport (SEATAC), expressed as HDD/year. The regression line of HDD on year slopes downward: as the climate becomes warmer, the number of HDD per year becomes smaller.

The slope of the regression line, as the climate warms, is negative (-19.051, or essentially, minus 20 HDD per year). The paired vertical and paired horizontal guidelines on the graph bound five years (2013 – 2017). Over these five years, the trend line shows a reduction of 100 HDD. The drop in HDD over the three years of decoupling (within the vertical guides for the boundary years of 2013 and 2017) is about 60 HDD due to the warming climate (and not taking short weather cycles or seasonality into account).

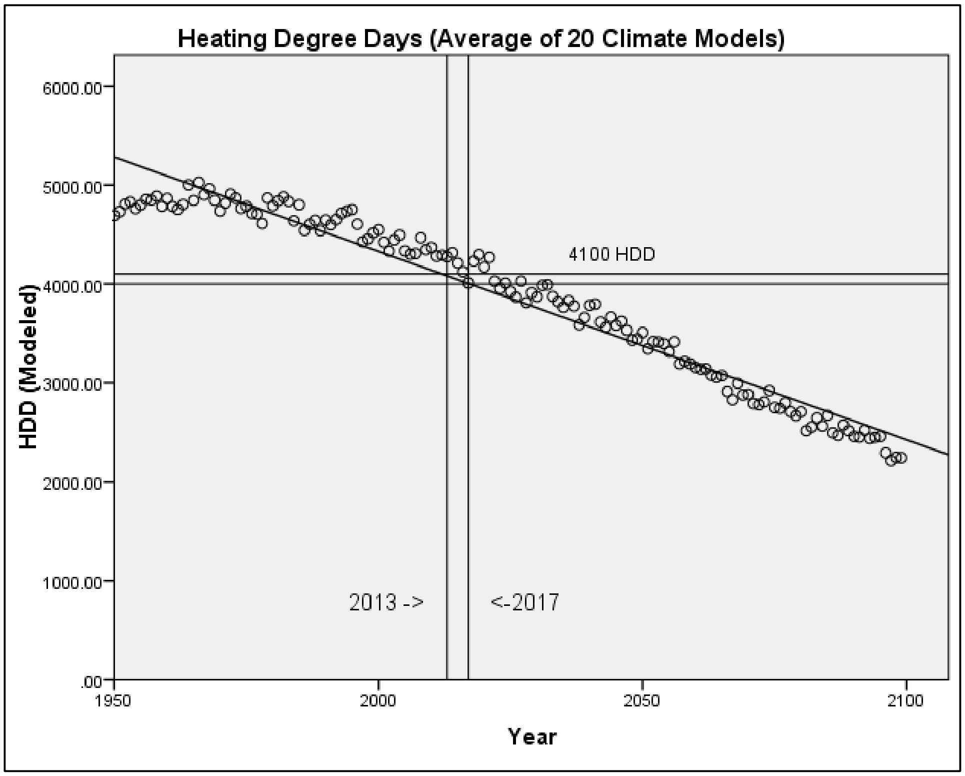

Figure XII.1: Modeled Climate Trend Line (Regression of HDD on Years) – DR 30.29 & External Data

If we extend this regression result using the derived equation (y = a +b*x), the trend line for HDD is at zero in the year 2227 which is 210 years in the future from 2017. We interpret this analysis to mean:

(1) Climate warming would be of primary importance for a study with a scope of 100 - 210 years.

(2) Climate warming is not a sizably meaningful effect for a study with a scope of 3 or 5 years.

Weather Cycles

One aspect of weather that influences results in this study is short warming cycles. These cycles are first indicated in Section VI. A graph of average (actual) residential natural gas customers' (Schedules 23 & 53) use (therms) shows the swing in cycles of local weather measured at SEA TAC (Figure XII.2). With data from 2001 through 2015, there is a down-cycle movement from 2001 through 2004 (3 years), followed by an up-cycle from 2009 (5 years). Then there is a down-cycle from 2009 to 2010 (1 year) followed by an up-cycle from 2010 to 2011 (1 year), and then a down-cycle from 2011 to 2014 (three years).

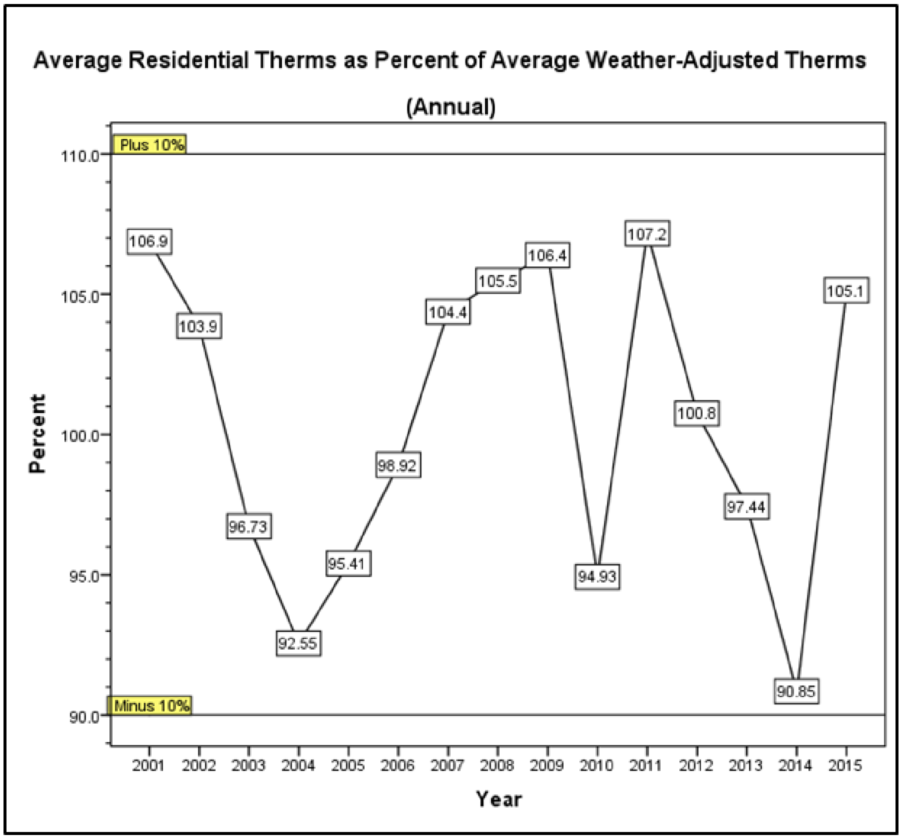

Figure XII.2: Residential Natural Gas (Sch 23 & 53) Therms Follow Local Weather Cycles – DR 30.29

The same information can be shown in terms of incremental gas bills as a percentage of normalized gas bills (Figure XII.3).

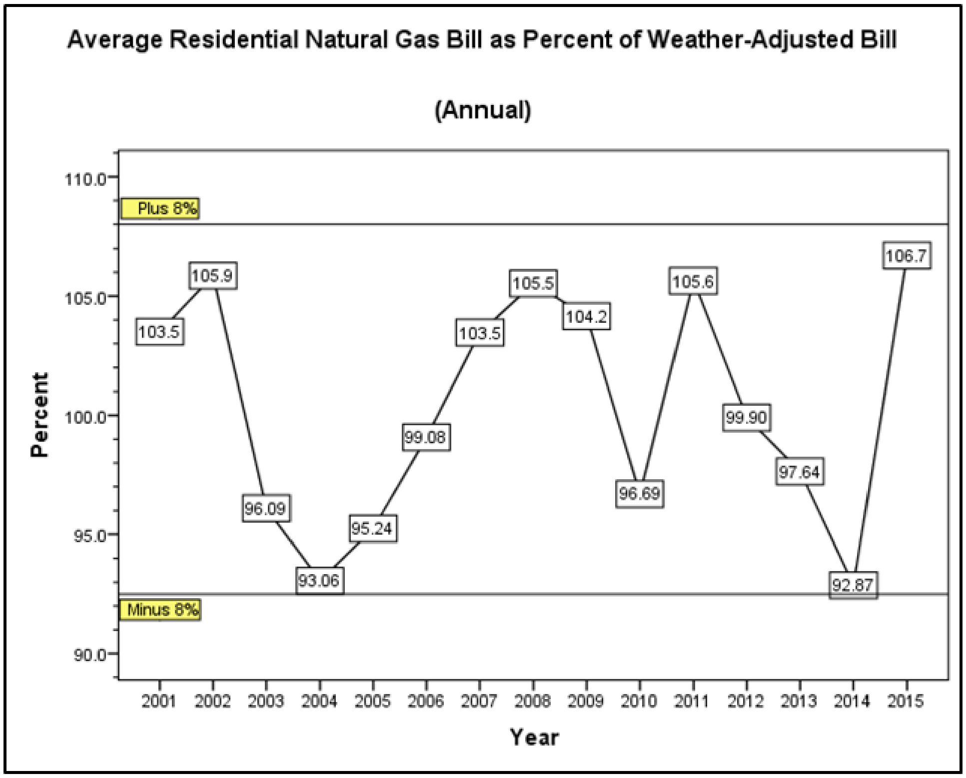

Figure XII.3: Residential Natural Gas (Sch. 23 & 53) Bills Follow the Local Weather Cycles – DR 30.29

Returning to HDD, this time to a difference of actual HDD vs. normal HDD and shifting focus from years to months, Figure XII.4 shows the weather linkage of months in the format of a bar chart. This is the three year decoupling period of the study.

This figure illustrates the difference between actual and normal heating degree days (HDD) from January, 2013 through September, 2016. A negative (red) value means warmer than normal weather (*i.e.*, actual HDDs were less than normal). A blue value means colder than normal weather. As discussed in Section VII of this study (where this figure was first presented as Figure VII.3), actual weather has been colder than normal in only 6 of the last 45 months of history. Monthly data in this time window show a prolonged pattern of warmer than normal weather.

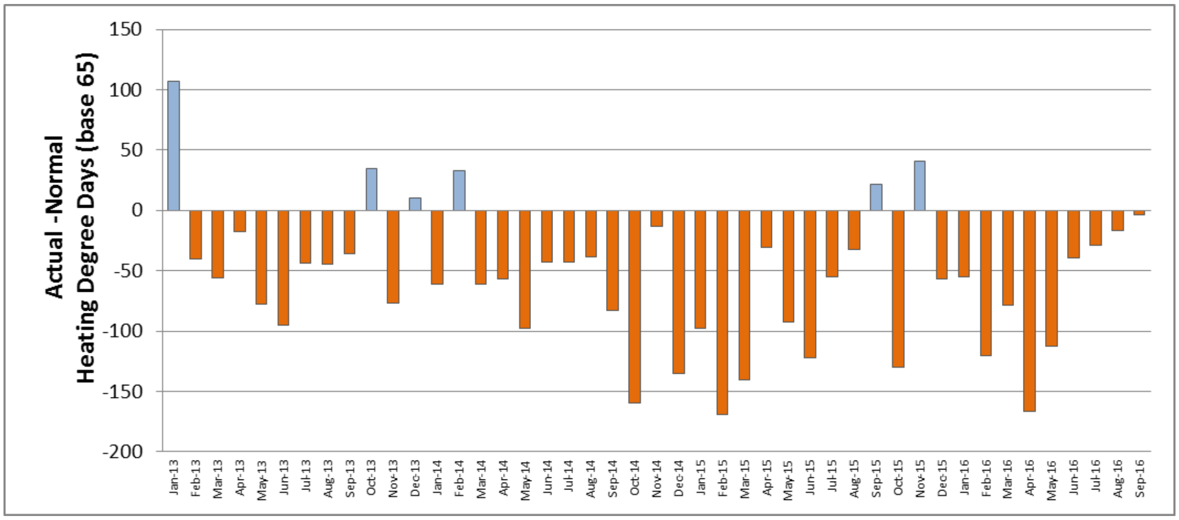

Figure XII.4: Three-Year Decoupling Period – Pattern of Warmer and Colder than Usual Months – DR 30.62

Warming in a local weather cycle creates adjacent years in which temperature is warmer than normal and there are fewer heating degree days in winter (while there may be an occasional month that is cooler). Because residential gas has a high heating sensitivity, less gas than normal is used during a warming cycle. The decoupling mechanism then increases the per unit cost of therms in the "true-up" each May 1st. This increases subsequent residential natural gas bills (Schedules 23 & 53).

Since warming typically occurs in the form of short cycles of years, the effect of the cap within the decoupling mechanism can easily be expected to cause revenue recovery of deferrals to be amortized over more than one year for decoupling groups for which heating energy is important (here, residential natural gas – Schedules 23 & 53). *Such local warming and cooling cycles are typical, rather than exceptional.* The pattern shown in Figure XII.4 includes a short warming cycle across the three years combined with the pattern of seasonality. Individual years are linked in weather changes and are not independent.

In addition to weather, changes in commodity cost is also a strong factor influencing variation in customer bills.

The Cost of Natural Gas as a Source of Additional Variation

The reason why a 5% cap for residential natural gas customers (Schedules 23 & 53) works is that a 5% difference is within the accustomed 8% bill variation for this decoupling group due to weather (Figure XII.3), additional variation due to short weather cycles and the additional variation due to seasonality. These three background variation factors combine to make a 5% change invisible against the background noise of all of these variations. Several other factors (for example, changes in household size) also contribute to the background noise.

For natural gas (but not for electricity) the largest contribution to background variation is large swings in the commodity cost of natural gas. Commodity cost is a pass-through to the customer; there is nothing in between the market and the customer to dampen these swings (Figure XII.5).

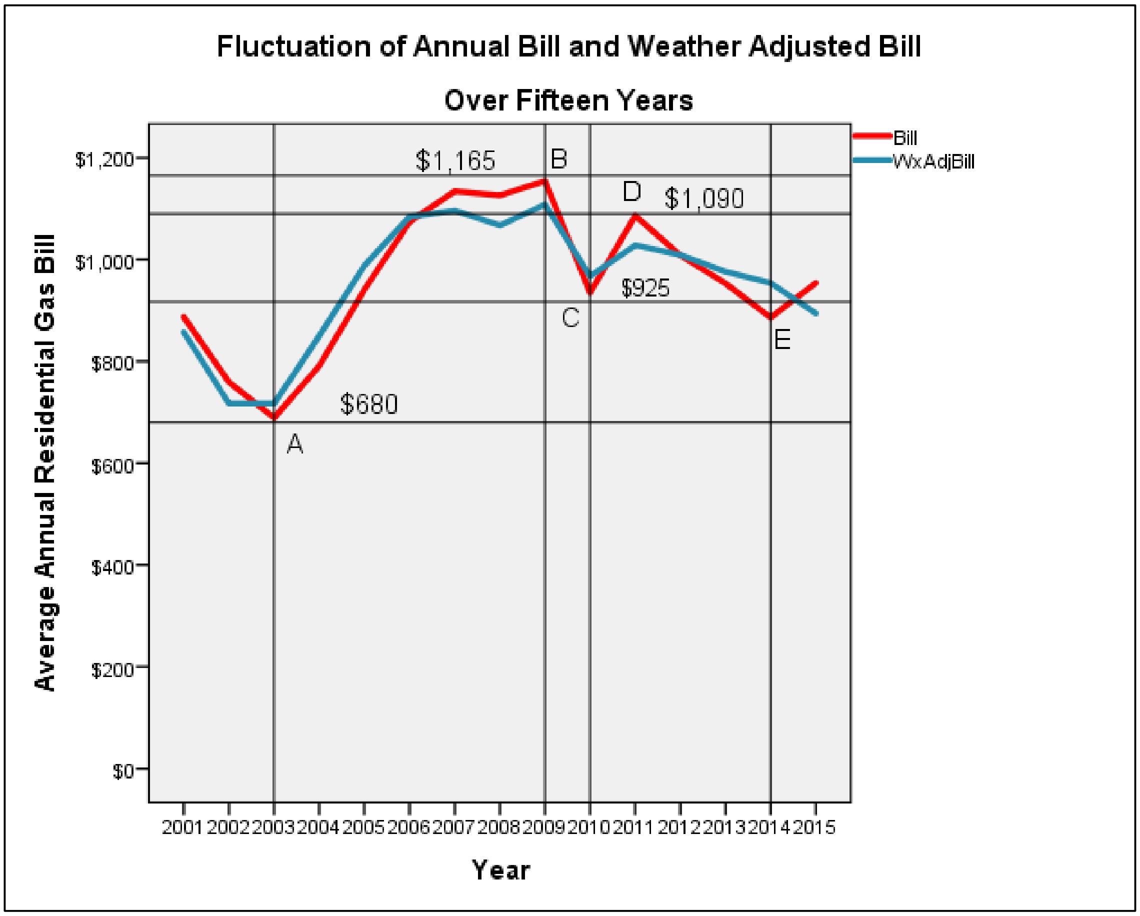

Figure XII.5: Fluction of Annual Bill and Annual Weather-Adjusted Bill over Fifteen Years – DR 30.68

As shown in Figure XII.5, swings in gas cost over a few years can be an increase of 71% over 6 years (A to B), a decrease of 21% over 1 year (B to C), an increase of 18% over 1 year (C to D) or a decrease of 15% (D to E) over three years. These differences, combined with weather cycle differences, weather differences and seasonality, and other factors would make it nearly impossible for a customer to notice the operation of a 5% cap for the natural gas residential decoupling group (Schedules 23 and 53).

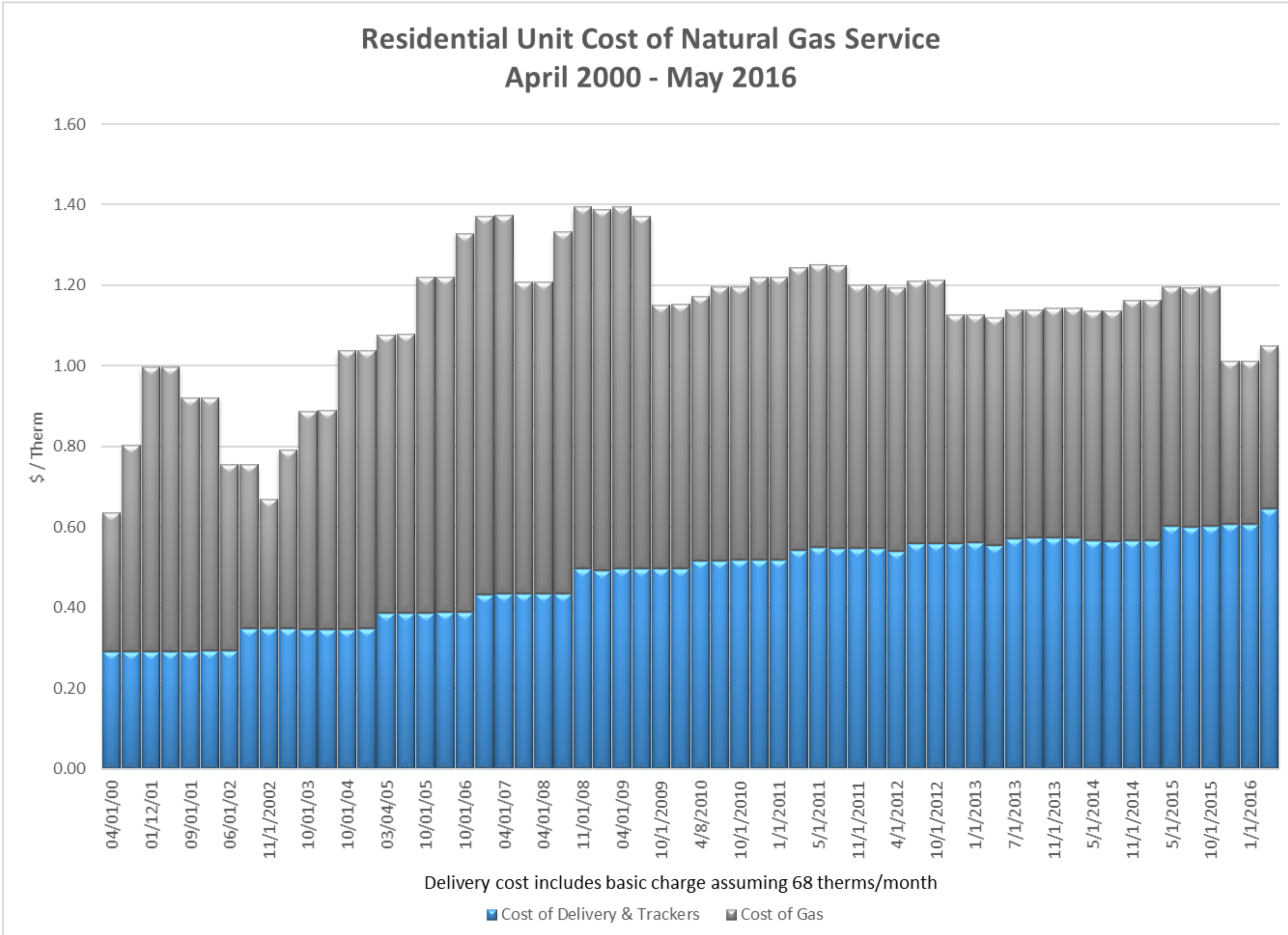

Figure XII.6: PSE Portrayal of Cost of Delivery & Trackers and Gas Cost – DR 30.68

Figure XII.6 goes to a deeper level, separating commodity and delivery cost for a typical customer using 68 therms per month. This graph provides more detail, but is compatible with Figure XII.5.

XIII. Reference Appendix IV – Typical Residential Bills

Table XIII.1: Typical Electric Bill 2016 Filing Source DR30.07 Attachment B

Puget Sound Energy					
2016 Electric Decoupling Filing					
Typical Residential Bill Impact of 2015 Change to Schedule 142 Decoupling					
Proposed Effective May 1, 2016					
		Customer Bill			
Month	kWh	Present	Proposed	$ Difference	% Difference
January	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
February	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
March	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
April	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
May	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
June	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
July	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
August	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
September	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
October	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
November	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
December	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
Annual Total	12,000	$ 1,256.88	$ 1,276.68	$ 19.80	1.58%
Monthly Average	1,000	$ 104.74	$ 106.39	$ 1.65	1.58%
Average Cents		10.47	10.64		

Rates		Present Rates Effective 1-1-16	Proposed Rates Effective 5-1-16	
Customer Monthly Charge:		$ 7.49	$ 7.49	per Month
Schedule 141 - ERF Rider - 1 Phase Basic Charge		$ 0.38	$ 0.38	per Month
Subtotal Base Monthly Charge		$ 7.87	$ 7.87	
Energy Charge:				
Schedule 7 first 600 kWh		$ 0.085578	$ 0.085578	$ / kWh
Schedule 129 - Low Income		$ 0.000913	$ 0.000913	$ / kWh
Schedule 140 - Property Tax Rider		$ 0.003205	$ 0.003205	$ / kWh
Schedule 141 - ERF Rider - First 600 kWh		$ 0.001114	$ 0.001114	$ / kWh
Schedule 142 - Decoupling Rider		$ 0.004729	$ 0.006382	$ / kWh
Subtotal Base First 600 kWh Charge		$ 0.095539	$ 0.097192	$ / kWh
Schedule 7 over 600 kWh		$ 0.104157	$ 0.104157	$ / kWh
Schedule 129 - Low Income		$ 0.000913	$ 0.000913	$ / kWh
Schedule 140 - Property Tax Rider		$ 0.003205	$ 0.003205	$ / kWh
Schedule 141 - ERF Rider - Over 600 kWh		$ 0.001357	$ 0.001357	$ / kWh
Schedule 142 - Decoupling Rider		$ 0.004729	$ 0.006382	$ / kWh
Subtotal Base Over 600 kWh Charge		$ 0.114361	$ 0.116014	$ / kWh
Energy Rider Schedules				
Schedule 95 - Power Cost Adjustment Clause		$ (0.001491)	$ (0.001491)	$ / kWh
Schedule 95A - Wind Power Production Credit		$ (0.003015)	$ (0.003015)	$ / kWh
Schedule 120 - Conservation Rider		$ 0.005557	$ 0.005557	$ / kWh
Schedule 132 - Merger Credit		$ (0.000370)	$ (0.000370)	$ / kWh
Schedule 133 - Regulatory Asset Tracker		$ -	$ -	$ / kWh
Schedule 137 - Renewable Energy Credit		$ (0.000083)	$ (0.000083)	$ / kWh
Schedule 194 - BPA Exchange Credit		$ (0.006794)	$ (0.006794)	$ / kWh
Subtotal Rider Schedules		$ (0.006196)	$ (0.006196)	$ / kWh
Total Per KWH Charge First 600 kWh		$ 0.089343		
Total Per KWH Charge Over 600 kWh		$ 0.108165		

Table XIII.2: Typical Electric Bill 2015 Filing Source DR20.07 Attachment B

Puget Sound Energy					
2015 Electric Decoupling Filing					
Typical Residential Bill Impact of 2015 Change to Schedule 142 Decoupling					
Proposed Effective May 1, 2015					
		Customer Bill			
Month	kWh	Present	Proposed	$ Difference	% Difference
January	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
February	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
March	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
April	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
May	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
June	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
July	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
August	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
September	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
October	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
November	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
December	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
Annual Total	12,000	$ 1,114.68	$ 1,151.28	$ 36.60	3.28%
Monthly Average	1,000	$ 92.89	$ 95.94	$ 3.05	3.28%
Average Cents		9.29	9.59		
Rates		Present Rates Effective 1-1-15	Proposed Rates Effective 5-1-15		
Customer Monthly Charge:		$ 7.490000	$ 7.490000	per Month	
Schedule 141 - ERF Rider - 1 Phase Basic Charge		$ 0.380000	$ 0.380000	per Month	
Subtotal Base Monthly Charge		$ 7.870000	$ 7.870000		
Energy Charge:					
Schedule 7 first 600 kWh		$ 0.085578	$ 0.085578	$ / kWh	
Schedule 129 - Low Income		$ 0.000856	$ 0.000856	$ / kWh	
Schedule 140 - Property Tax Rider		$ 0.002870	$ 0.002870	$ / kWh	
Schedule 141 - ERF Rider - First 600 kWh		$ 0.001114	$ 0.001114	$ / kWh	
Schedule 142 - Decoupling Rider		$ 0.001685	$ 0.004729	$ / kWh	
Subtotal Base First 600 kWh Charge		$ 0.092103	$ 0.095147	$ / kWh	
Schedule 7 over 600 kWh		$ 0.104157	$ 0.104157	$ / kWh	
Schedule 129 - Low Income		$ 0.000856	$ 0.000856	$ / kWh	
Schedule 140 - Property Tax Rider		$ 0.002870	$ 0.002870	$ / kWh	
Schedule 141 - ERF Rider - Over 600 kWh		$ 0.001357	$ 0.001357	$ / kWh	
Schedule 142 - Decoupling Rider		$ 0.001685	$ 0.004729	$ / kWh	
Subtotal Base Over 600 kWh Charge		$ 0.110925	$ 0.113969	$ / kWh	
Energy Rider Schedules					
Schedule 95 - Power Cost Adjustment Clause		$ (0.001491)	$ (0.001491)	$ / kWh	
Schedule 95A - Wind Power Production Credit		$ (0.002724)	$ (0.002724)	$ / kWh	
Schedule 120 - Conservation Rider		$ 0.005297	$ 0.005297	$ / kWh	
Schedule 132 - Merger Credit		$ (0.000354)	$ (0.000354)	$ / kWh	
Schedule 133 - Regulatory Asset Tracker		$ -	$ -	$ / kWh	
Schedule 137 - Renewable Energy Credit		$ (0.000181)	$ (0.000181)	$ / kWh	
Schedule 194 - BPA Exchange Credit		$ (0.015170)	$ (0.015170)	$ / kWh	

Table XIII.3: Typical Electric Bill 2014 Filing Source DR01.05 Attachment G

Puget Sound Energy					
2014 Electric Decoupling Filing					
Typical Residential Bill Impact of 2014 Change to Schedule 142 Decoupling					
Proposed Effective May 1, 2014					
		Customer Bill			
Month	kWh	Present	Proposed	$ Difference	% Difference
January	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
February	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
March	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
April	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
May	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
June	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
July	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
August	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
September	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
October	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
November	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
December	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
Annual Total	12,000	$ 1,169.76	$ 1,170.48	$ 0.72	0.06%
Monthly Average	1,000	$ 97.48	$ 97.54	$ 0.06	0.06%
Average Cents		9.75	9.75		

Rates		Present Rates Effective 1-1-14	Proposed Rates Effective 5-1-14	
Customer Monthly Charge:		$ 7.49	$ 7.49	per Month
Energy Charge:				
Schedule 7 first 600 kWh		8.5578	8.5578	¢ / kWh
Schedule 7 over 600 kWh		10.4157	10.4157	¢ / kWh
Schedule 95 - Power Cost Adjustment Clause		(0.0528)	(0.0528)	¢ / kWh
Schedule 95A - Wind Power Production Credit		(0.2947)	(0.2947)	¢ / kWh
Schedule 120 - Conservation Rider		0.4632	0.4632	¢ / kWh
Schedule 129 - Low Income		0.0856	0.0856	¢ / kWh
Schedule 132 - Merger Credit		(0.0345)	(0.0345)	¢ / kWh
Schedule 133 - Regulatory Asset Tracker		-	-	¢ / kWh
Schedule 137 - Renewable Energy Credit		(0.0850)	(0.0850)	¢ / kWh
Schedule 140 - Property Tax Rider		0.2238	0.2238	¢ / kWh
Schedule 141 - ERF Rider - 1 Phase Basic Charge		$ 0.38	$ 0.38	per Month
Schedule 141 - ERF Rider - First 600 kWh		0.1114	0.1114	¢ / kWh
Schedule 141 - ERF Rider - Over 600 kWh		0.1357	0.1357	¢ / kWh
Schedule 142 - Decoupling Rider		0.1628	$ 0.1685	¢ / kWh
Schedule 194 - BPA Exchange Credit		(0.9279)	(0.9279)	¢ / kWh

Table XIII.4: Typical Electric Bill 2013 Filing

Puget Sound Energy
Residential Customer Impacts

Line No.	Month	kWh	Customer Bill: Present	Customer Bill: Present Excluding Property Tax Rider Schedule 140	$ Difference	% Difference
	(a)	(b)	(c)	(c)	(e)	(f)
1	January	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
2	February	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
3	March	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
4	April	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
5	May	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
6	June	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
7	July	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
8	August	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
9	September	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
10	October	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
11	November	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
12	December	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
13						
14	Annual Total	12,000	$ 1,187.36	$ 1,206.90	$ 19.54	1.65%
15						
16	Monthly Average	1,000	$ 98.95	$ 100.57	$ 1.63	1.65%
17						
18	Average Cents				0.16	
19						
20						
21	Rates			Proposed Rate (Base + ERF) Effective July 1, 2013	Proposed Rate (Base + ERF + Decoupling) Effective July 1, 2013	
22	Customer Monthly Charge:			$ 7.49	$ 7.49	$ per Month
23	Energy Charge:					
24	Schedule 7 first 600 kWh			8.5578	8.5578	¢ / kWh
25	Schedule 7 over 600 kWh			10.4157	10.4157	¢ / kWh
26	Schedule 95 - Power Cost Adjustment Clause			-	-	¢ / kWh
27	Schedule 95A - Federal Incentive Credit			(0.3323)	(0.3323)	¢ / kWh
28	Schedule 120 - Conservation Rider			0.4632	0.4632	¢ / kWh
29	Schedule 129 - Low Income			0.0777	0.0777	¢ / kWh
30	Schedule 132 - Merger Credit			(0.0335)	(0.0335)	¢ / kWh
31	Schedule 133 - Regulatory Asset Tracker			-	-	¢ / kWh
32	Schedule 137 - Renewable Energy Credit			(0.0348)	(0.0348)	¢ / kWh
33	Schedule 140 - Property Tax Rider			0.2238	0.2238	¢ / kWh
34	Schedule 141 - ERF Rider - 1 Phase Basic Charge			$ 0.38	$ 0.38	$ per Month
35	Schedule 141 - ERF Rider - First 600 kWh			0.1114	0.1114	¢ / kWh
36	Schedule 141 - ERF Rider - Over 600 kWh			0.1357	0.1357	¢ / kWh
37	Schedule 142 - Decoupling Rider			-	0.1628	¢ / kWh
37	Schedule 194 - BPA Exchange Credit			(0.6785)	(0.6785)	¢ / kWh

Table XIII.5: Typical Gas Bill 2016 Filing Source DR30.07 Attachment C

	Current Rates		Schedule 142 Change	
Puget Sound Energy				
2016 Gas Decoupling Filing				
Typical Residential Bill Impact of 2016 Change to Schedule 142 Decoupling				
Proposed Effective May 1, 2016				
	Rates (1)	Charges	Rates	Charges
Volume (therms)	68		68	
Customer charge ($/month)				
Basic charge	$ 10.34	$ 10.34	$ 10.34	$ 10.34
ERF (2) adjusting charge (Schedule 141)	$ (0.05)	$ (0.05)	$ (0.05)	$ (0.05)
Subtotal	$ 10.29	$ 10.29	$ 10.29	$ 10.29
Volumetric charges ($/therm)				
Delivery charge (Schedule 23)	$ 0.36492		$ 0.36492	
Property tax charge (Schedule 140)	$ 0.02525		$ 0.02525	
ERF (2) adjusting charge (Schedule 141)	$ (0.00171)		$ (0.00171)	
Decoupling charge (Schedule 142)	$ 0.03930		$ 0.07157	
Low income charge (Schedule 129)	$ 0.00797		$ 0.00797	
Cost Recovery Mechanism (CRM)	$ 0.00818		$ 0.00818	
Subtotal	$ 0.44391	$ 30.19	$ 0.47618	$ 32.38
Conservation charge (Schedule 120)	$ 0.01504	$ 1.02	$ 0.01504	$ 1.02
Merger rate credit (Schedule 132)	$ (0.00377)	$ (0.26)	$ (0.00377)	$ (0.26)
Cost of gas (Schedule 101)	$ 0.44113		$ 0.44113	
Deferral amortization (Schedule 106)	$ (0.03601)		$ (0.03601)	
Deferral amortization (Schedule 106-A)	$ -		$ -	
Subtotal	$ 0.40512	$ 27.55	$ 0.40512	$ 27.55
Total volumetric charges	$ 0.86030	$ 58.50	$ 0.89257	$ 60.69
Total monthly bill		$ 68.79		$ 70.98
Change from bill under current rates				$ 2.19
Percent change from bill under current rates				3.2%
Total volumetric rates less gas costs	$ 0.45518		$ 0.48745	

(1) Rates for Schedule 23 customers in effect January 1, 2016
(2) Expedited Rate Filing (ERF)

Table XIII.6: Typical Gas Bill 2015 Filing Source DR20.07 Attachment C

Puget Sound Energy
2015 Gas Decoupling Filing
Typical Residential Bill Impact of 2014 Change to Schedule 142 Decoupling
Proposed Effective May 1, 2015

	Current Rates		Schedule 142 Change	
	Rates (1)	Charges	Rates	Charges
Volume (therms)	68		68	
Customer charge ($/month)				
Basic charge	$ 10.34	$ 10.34	$ 10.34	$ 10.34
ERF (2) adjusting charge (Schedule 141)	$ (0.05)	$ (0.05)	$ (0.05)	$ (0.05)
Subtotal	$ 10.29	$ 10.29	$ 10.29	$ 10.29
Volumetric charges ($/therm)				
Delivery charge (Schedule 23)	$ 0.36492		$ 0.36492	
Property tax charge (Schedule 140)	$ 0.02764		$ 0.02764	
ERF (2) adjusting charge (Schedule 141)	$ (0.00171)		$ (0.00171)	
Decoupling charge (Schedule 142)	$ 0.00677		$ 0.03930	
Low income charge (Schedule 129)	$ 0.00651		$ 0.00651	
Cost Recovery Mechanism (CRM)	$ 0.00256		$ 0.00256	
Subtotal	$ 0.40669	$ 27.65	$ 0.43922	$ 29.87
Conservation charge (Schedule 120)	$ 0.01268	$ 0.86	$ 0.01268	$ 0.86
Merger rate credit (Schedule 132)	$ (0.00346)	$ (0.24)	$ (0.00346)	$ (0.24)
Cost of gas (Schedule 101)	$ 0.56176		$ 0.56176	
Deferral amortization (Schedule 106)	$ 0.03348		$ 0.03348	
Deferral amortization (Schedule 106-A)	$ -		$ -	
Subtotal	$ 0.59524	$ 40.48	$ 0.59524	$ 40.48
Total volumetric charges	$ 1.01115	$ 68.75	$ 1.04368	$ 70.97
Total monthly bill		$ 79.04		$ 81.26
Change from bill under current rates				$ 2.22
Percent change from bill under current rates				2.8%
Total volumetric rates less gas costs	$ 0.41591		$ 0.44844	

(1) Rates for Schedule 23 customers in effect January 1, 2015
(2) Expedited Rate Filing (ERF)

Table XIII.7: Typical Gas Bill 2014 Filing Source DR01.05 Attachment H

Puget Sound Energy				
2014 Gas Decoupling Filing				
Typical Residential Bill Impact of 2014 Change to Schedule 142 Decoupling				
Proposed Effective May 1, 2014				
	Current Rates		Schedule 142 Change	
	Rates (1)	Charges	Rates	Charges
Volume (therms)	68		68	
Customer charge ($/month)				
Basic charge	$ 10.34	$ 10.34	$ 10.34	$ 10.34
ERF (2) adjusting charge (Schedule 141)	$ (0.05)	$ (0.05)	$ (0.05)	$ (0.05)
Subtotal	$ 10.29	$ 10.29	$ 10.29	$ 10.29
Volumetric charges ($/therm)				
Delivery charge (Schedule 23)	$ 0.36492		$ 0.36492	
Property tax charge (Schedule 140)	$ 0.02149		$ 0.02149	
ERF (2) adjusting charge (Schedule 141)	$ (0.00171)		$ (0.00171)	
Decoupling charge (Schedule 142)	$ 0.02101		$ 0.00677	
Low income charge (Schedule 129)	$ 0.00710		$ 0.00710	
Subtotal	$ 0.41281	$ 28.07	$ 0.39857	$ 27.10
Conservation charge (Schedule 120)	$ 0.01231	$ 0.84	$ 0.01231	$ 0.84
Merger rate credit (Schedule 132)	$ (0.00367)	$ (0.25)	$ (0.00367)	$ (0.25)
Cost of gas (Schedule 101)	$ 0.58452		$ 0.58452	
Deferral amortization (Schedule 106)	$ (0.01294)		$ (0.01294)	
Deferral amortization (Schedule 106-A)	$ -		$ -	
Subtotal	$ 0.57158	$ 38.87	$ 0.57158	$ 38.87
Total volumetric charges	$ 0.99303	$ 67.53	$ 0.97879	$ 66.56
Total monthly bill		$ 77.82		$ 76.85
Change from bill under current rates				$ (0.97)
Percent change from bill under current rates				-1.2%
Total volumetric rates less gas costs	$ 0.42145		$ 0.40721	
(1) Rates for Schedule 23 customers in effect January 1, 2014				
(2) Expedited Rate Filing (ERF)				

Table XIII.8: Typical Gas Bill 2013 Filing

Puget Sound Energy
Expedited Rate Filing Effective July 1, 2013
Residential Bill Impact of Implementation of Schedule 142

	Current Rates		July 2013 Rates	
	Rates (1)	Charges	Rates	Charges
Volume (therms)	68		68	
Customer charge ($/month)				
Basic charge	$ 10.34	$ 10.34	$ 10.34	$ 10.34
ERF (2) adjusting charge Schedule 141)	$ -	$ -	$ -	$ -
Subtotal	$ 10.34	$ 10.34	$ 10.34	$ 10.34
Volumetric charges ($/therm)				
Delivery charge (Schedule 23)	$ 0.38641		$ 0.38641	
Property tax charge (Schedule 140)	$ -		$ -	
ERF (2) adjusting charge (Schedule 141)	$ -		$ -	
Decoupling charge (Schedule 142)	$ -		$ 0.02101	
Low income charge (Schedule 129)	$ 0.00599		$ 0.00599	
Subtotal	$ 0.39240	$ 26.68	$ 0.41341	$ 28.11
Conservation charge (Schedule 120)	$ 0.01231	$ 0.84	$ 0.01231	$ 0.84
Merger rate credit (Schedule 132)	$ (0.00345)	$ (0.23)	$ (0.00345)	$ (0.23)
Cost of gas (Schedule 101)	$ 0.60656		$ 0.60656	
Deferral amortization (Schedule 106)	$ (0.04029)		$ (0.04029)	
Deferral amortization (Schedule 106-A)	$ -		$ -	
Subtotal	$ 0.56627	$ 38.51	$ 0.56627	$ 38.51
Total volumetric charges	$ 0.96753	$ 65.80	$ 0.98854	$ 67.23
Total monthly bill		$ 76.14		$ 77.57
Change from bill under previous rates				$ 1.43
Percent change from bill under previous rates				1.9%
Total volumetric rates less gas costs	$ 0.40126		$ 0.42227	

(1) Rates for Schedule 23 customers in effect May 1, 2013.
(2) Expedited Rate Filing (ERF)

XIV. Reference Appendix V – Responses to Data Requests

While many hundreds of Data Requests were submitted to PSE, the following included DRs are those cited in this report. (Note that DR Attachments, such as spreadsheets, are not included here.)

Responses Included within this Appendix		
First Year	**Second Year**	**Third Year**
1.05	20.07	30.07
1.14	20.08	30.08
1.15	20.09	30.10
1.19	20.14	30.11
1.20	20.15	30.13
1.21	20.17	30.14
1.22	20.19	30.15
1.23	20.21	30.18
1.24	20.22	30.19
1.25	20.29	30.20
1.29	20.31	30.21
1.32	20.37	30.29
1.38	20.39	30.36
4.01	20.40	30.37
	20.44	30.39
	20.45	30.42
	20.49	30.43
	20.52	30.56
	20.55	30.59
	20.57	30.62
	20.58	30.63
		30.64
		30.65
		30.66
		30.67
		30.68
		30.69
		30.69 - Supplement
		30.70

Responses to First Year Data Requests

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.05

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.05:

Please provide copies of the "Decoupling Work-papers and Spread-Sheets" used to calculate rates and deferrals. Subsequent to our review of these documents we will request demonstration of how the calculations are implemented in the spread-sheets including: tariff tracker adjustments, deferrals, (k) factor adjustments, and allowable revenue.

Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s. ("PSE") Response to H. Gil Peach & Associates Data Request No. 01.05, please find a Microsoft Excel file that calculates the decoupling deferrals for the time period July 2013 through June 2014.

Attached as Attachments B and C to PSE's Response to H. Gil Peach & Associates Data Request No. 01.05, please find Microsoft Excel files that calculate the electric and gas decoupling rates, respectively, effective July 1, 2013.

Attached as Attachments D, E and F to PSE's Response to H. Gil Peach & Associates Data Request No. 01.05, please find Microsoft Excel files that calculate changes to the electric non-residential rates, electric schedule 26 & 31 rates and gas decoupling rates, respectively, effective January 1, 2014.

Attached as Attachments G and H to PSE's Response to H. Gil Peach & Associates Data Request No. 01.05, please find Microsoft Excel files that calculate changes to the electric and gas decoupling rates, respectively, effective May 1, 2014.

Attached as Attachments I and J to PSE's Response to H. Gil Peach & Associates Data Request No. 01.05, please find Microsoft Excel files that revise the electric non-residential and electric schedule 26 & 31 allowed revenue per customer, respectively, effective July 1, 2014.

Attached as Attachment K to PSE's Response to H. Gil Peak & Associates Data Request No. 01.05, please find a Microsoft Excel file that revises the electric non-residential rates, effective July 1, 2014.

Due to its large size, Attachment A - K to PSE's Response to H. Gil Peach & Associates Data Request No. 01.05 are submitted in electronic format only.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.14

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.14:

Please provide the formula for determining the energy assistance amount for a client.

Response:

For the PSE HELP program 2014-2015:

The formula used to determine energy assistance amounts for a client is as follows:

PSE Formula

$$\left(.69 - \left(\frac{152.27}{1748.65 - mi/ha}\right)\right) \times AEC = \text{Benefit Award}$$

PSE Formula if LIHEAP Awarded

$$\left(.69 - \left(\frac{152.27}{1748.65 - mi/ha}\right)\right) \times (AEC - LIHEAP) = \text{Benefit Award}$$

mi = monthly income

ha = household size adjuster

AEC = annual energy cost

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.15

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.15:

Please provide some presentation regarding the low-income programs and how they operate at the sessions at PSE from November 18-20, with an opportunity to discuss.

Response:

Attached as Attachments A and B to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 01.15, please find a PDF of the Microsoft PowerPoint presentations that provide overviews of its low income programs for conservation and energy assistance, respectively.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.19

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.19:

Please provide a description of any modifications to conservation programs targeted at low-income customers since the inception of the decoupling mechanisms; modifications include changes to funding levels as well as changes to specific measures or programs.

Response:

According to the Order No. 07, pages 76-77, in Docket Nos. UE-121697 and UG-121705 (consolidated) and in reference to the Multi-party Agreement, Puget Sound Energy, Inc. ("PSE") was granted the discretionary authority to add $500,000 annually to its residential low income electric program and $100,000 annually to its investor contribution. In response, PSE added $500,000 to the 2014 Schedule 201 Electric Program budget and $100,000 to its Schedule 201 investor contribution.

Schedule 201 Budget Comparison: 2013 vs. 2014

	2013	2014
Sch 201 Electric	$ 2,425,462	$ 3,098,684
Sch 201 Gas	$ 301,309	$ 369,443
Investor Contribution	$ 300,000	$ 400,000

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.20

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.20:

Have client eligibility rules changed, have there been changes in the levels of funding and, if so, for which programs? Have there been in changes in the level services or measures provided?

Response:

No. Puget Sound Energy, Inc. ("PSE") continues to defer to the Washington State Department of Commerce on issues related to client eligibility. For changes in funding, please reference the PSE Response to H. Gil Peach & Associates Data Request No. 01.19. The fundamental structure of the Residential Low Income program has remained the same.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.21

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.21:

Please provide program budgets for the 2 years prior to decoupling as well as the same budgets covering the decoupling period.

Response:

Attached as Attachments A and B to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 01.21, please find Microsoft Excel spreadsheets containing PSE's energy efficiency program budgets prior to decoupling, 2011 and 2012, respectively.

Attached as Attachments C and D to PSE's Response to H. Gil Peach & Associates Data Request No. 01.21, please find Microsoft Excel spreadsheets containing PSE's energy efficiency program budgets including the decoupling period, 2013 and 2014, respectively.

At the time of this response, the 2015 budget is still under development.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.22

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.22:

Please provide information on any dates and changes in senior management roles as they relate to energy efficiency.

Response:

Below, please find a timeline of the changes in senior management roles as they relate to energy efficiency since 2005.

2005
Cal Shirley becomes Vice President of Energy Efficiency Services

2007 – present
Bob Stolarski becomes Director of Energy Efficiency Services

December 2012
Andy Wappler, Vice President of Corporate Affairs transitions management of Energy Efficiency from Cal Shirley, Vice President of Energy Efficiency Services.

August, 2014
Jason Teller, Vice President of Customer Solutions, transitions management of Energy Efficiency from Andy Wappler.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.23

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.23:

Please provide information on any energy efficiency and/or low-income presentations to the Board for two years prior to the first cycle evaluation analysis window and during the first cycle evaluation analysis time window (for example, please provide any relevant minutes from board meetings for this period.

Response:

There have been no Energy Efficiency department-specific presentations to the Puget Sound Energy, Inc. ("PSE") Board of Directors in the last two years. There has not been an energy assistance presentation to the Board since 2008.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.24

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.24:

Is the company aware of any unanticipated side effects that are associated with the decoupling mechanisms? If so, please explain.

Response:

Puget Sound Energy, Inc. ("PSE") is not aware of any unanticipated side effects associated with its decoupling mechanism. One often noted concern with decoupling is the potential for degradation in service quality. However, PSE has operated for many years under a series of service quality indices ("SQI") and reliability standards mandated by the Washington Utilities and Transportation Commission ("WUTC") that have financial penalties for failure to achieve minimum criteria.

Attached as Attachments A through C to PSE's Response to H. Gil Peach & Associates Data Request No. 01.24 are Adobe PDF copies of PSE's SQI and Electric Reliability Reports to the WUTC for the years 2011 through 2013.

Due to its large size, Attachment A - C to PSE's Response to H. Gil Peach & Associates Data Request No. 01.24 are submitted in electronic format only.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.25

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.25:

One of the team's tasks is to complete an examination of whether and how the change to rate design for Schedule 26 and 31 affects conservation achievement by these customers. The evaluation will examine whether there is conclusive evidence that the change had an appreciable effect on customers' energy efficiency achievements, including but not limited to achievements made through customer participation in PSE's energy efficiency program. The part about what these customers achieve outside of PSE's programs appears to require information that may or may not currently exist, and might require contact with and discussions with a sampling of the customers. However, we note that in the Statement of Work, "the consultant is expected to rely primarily on existing data from PSE". Will PSE have data on what these customers are accomplishing outside PSE programs or is that information we will have to gather from the customers?

Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach and Associates Data Request No. 01.25 is an Microsoft Excel workbook, with tabs that represent conservation achieved by customers served under schedule 26 and 31 through PSE's energy efficiency programs, including custom conservation grants installed from June 30 through November 2014 for these schedules, schedule 26 and 31 installations from July 1, 2012 through June 30, 2013, conservation measures installed in schedules 26 and 31 customer locations from July 1, 2013 through June 30, 2014, and a summary table of savings for the commensurate schedules and timeframes.

Attached as Attachment B to PSE's Response to H. Gil Peach and Associates Data Request No. 01.25 is a Microsoft Excel workbook containing a table of planned custom conservation projects.

Attached as Attachment C to PSE's Response to H. Gil Peach and Associates Data Request No. 01.25 is an Adobe PDF file containing the 2012-2013 biennial view of PSE's planned savings and expenditures.

Attached as Attachment D to PSE's Response to H. Gil Peach and Associates Data Request No. 01.25 is an Adobe PDF file containing PSE's 2013-specific planned savings and expenditures.

Attached as Attachment E to PSE's Response to H. Gil Peach and Associates Data Request No. 01.25 is an Adobe PDF file containing PSE's 2014-specific planned savings and expenditures.

Attached as Attachment F to PSE's Response to H. Gil Peach and Associates Data Request No. 01.25 is an Adobe PDF file containing PSE's 2014-2015 biennial planned savings and expenditures.

When assessing the impact of decoupling, PSE suggests that the evaluator look at the "Date Project Enter in CSY" column, as it gives the time that PSE became aware of the project. This date would be helpful to compare the impact of the decoupling order (July 1st, 2013) and the impact of the rate schedule 26 and 31 change (January 1, 2014) on incoming projects.

PSE also encourages the evaluator to look at the energy efficiency targets (included as an attachment to the question response) outlined in our 2012-2013 Biennial Conservation Plan (BCP) and 2014-2015 BCP. These targets are based on the market assessment by a third-party contractor and give a good indication of energy efficient market conditions. Between the 2012-2013 BCP and the 2014-2015 BCP, the efficiency targets dropped significantly, which indicates the energy efficiency market in 2014 was significantly different compared to 2013, independent of decoupling.

PSE has no data for customer activity outside of its programs.

Due to its large size, Attachment A - B to PSE's Response to H. Gil Peach & Associates Data Request No. 01.25 are submitted in electronic format only.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.29

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.29:

For the sessions at PSE from November 18-20, please provide a topic for discussion of any notable changes to staffing for the energy efficiency and low-income assistance program areas for three years prior to decoupling, and since decoupling. What we are looking for are any meaningful changes that may be related to decoupling.

Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 01.29, please find an Adobe PDF file with the current functional Customer Energy Management organizational chart that includes the number of Full-Time Equivalent staff for each function, along with the number of FTEs in other PSE organizations that also charge the Conservation Rider.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.32

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.32:

What are the positive results of decoupling from a PSE perspective? What are the negative results from a PSE perspective? Please explain the net benefit of decoupling to the Company based on experience to date.

Response:

From the perspective of Puget Sound Energy, Inc. ("PSE"), there are a number of positive results of decoupling. First, by removing the "throughput incentive" created by recovering a substantial portion of the company's fixed costs through volumetric energy sales, decoupling has mitigated PSE's financial disincentive to encourage its customers to embrace energy efficiency. Similarly, decoupling removes the financial disincentive for PSE to support its customers interest in rooftop solar and similar types of distributed generation that allow customers to have more control over their energy needs, both in terms of its price as well as its environmental impacts.

PSE is unaware of any negative results associated with its decoupling mechanism. Please see PSE's Response to H. Gil Peach & Associates Data Request No. 01.24 for an elaboration on this part of this request.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 01.38

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 01.38:

Please provide an explanation and/or any materials available that illustrate the review of PSE's decoupling rate calculations and the ongoing review of the associated revenue deferrals impacting its financial statements.

Response:

The rates approved by the Washington Utilities and Transportation Commission ("WUTC") for Puget Sound Energy, Inc.'s ("PSE") decoupling mechanisms have gone through extensive review at multiple points of time. The initial decoupling rates, which went into effect on July 1, 2013, were reviewed by the WUTC and were available for review by all intervenors in Docket Nos. UE-121697 and UG-121705. As noted in PSE's Response to H. Gil Peach & Associates Data Request No. 01.05, there were additional filings for changes to these rates, which went into effect on January 1, 2014 and May 1, 2014. These filings were available for review by all of the intervenors in the original decoupling dockets. At a minimum, all of these filings were reviewed by WUTC Staff, as they are required to present a summary of their review of these filings to the WUTC Commissioners as part of the approval process.

With regard to the ongoing review of the associated decoupling revenue deferrals, these calculations, which rely on the same workpapers provided in the decoupling rate filings, are reviewed by PSE staff in its Rates and Accounting departments. Together, they have developed detailed accounting instructions to help guide the proper and accurate tracking of the decoupling deferrals. Attached as Attachments A and B to PSE's Response to H. Gil Peach & Associates Data Request No. 01.38 are copies of the accounting instructions developed for rates that went into effect on July 1, 2013 and the updated accounting instructions associated with the modified decoupling mechanisms that went into effect on January 1, 2014, respectively.

PSE's Rates and Accounting staff also have worked closely with PSE's outside financial auditors, PricewaterhouseCoopers LLP ("PWC"), to ensure the accurate recording of the decoupling revenue deferrals. This was particularly important to PWC, given the material change in the way PSE was expected to recognize revenues beginning in 2013. PSE's review includes determining whether PSE is fulfilling its Sarbanes-Oxley obligations for ensuring proper internal controls when reporting these deferrals. Ultimately, PWC must satisfy themselves of the veracity of these figures as part of their ongoing review and attestation of PSE's financial statements. Attached as Attachment C to PSE's Response to H. Gil Peach & Associates Data Request No. 01.38 is a copy of PWC's Report of Independent Registered Public Accounting Firm to PSE's Board of Directors for calendar year 2013.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 04.01

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 04.01:

In Order 07 for consolidated Docket UE-121697 and Docket UG-121705, Page 89-90, §§214-2015, the Commission notes, "We approve the rate plan in part because it is an innovative approach that will provide incentives to PSE to cut costs in order to earn its authorized rate of return. It is important that the Commission monitor how, and how well these incentives, operate to improve efficiency and reduce costs…." And, further, "…PSE will be asked to present a status report on cost-cutting and other efficiency initiatives."

a. Please provide a copy of each of any such status reports on cost-cutting.

b. Please explain how the rate plan provides incentives to PSE to cut costs in order to earn its authorized rate of return.

c. Cost-cutting typically (but not always) requires a reduction in levels of activity or service. Please explain the extent to which each cost-cutting measure creates a reduction in service or, for each measure in turn, that cost-cutting does not create a reduction in service.

Response:

a. In an August 28, 2014 recessed open meeting related to Docket numbers UE-121697, UG-121705, UE-130137 and UG-130138, Puget Sound Energy, Inc. ("PSE") provided a presentation to the Washington Utilities and Transportation Commission ("WUTC") representing a status report on PSE's cost-cutting and other efficiency initiatives that are underway during the rate plan period. Attached as Attachment A to PSE's response to H.Gil Peach & Associates Data Request No. 04.01, please find the Power Point report presented at the August 28, 2014 meeting.

PSE has also filed reports for both Electric and Gas operations on its actual O&M cost per customer for the twelve months ended June 30, 2014 and for the twelve months ended December 31, 2014.

- The reports for Electric and Gas operations for the twelve months ended June 30, 2014, are included in the October 30, 2014 compliance filing under Docket number UE-121697, et al. The reports provided under this compliance filing are attached as Attachment B to PSE's response to H.Gil Peach & Associates Data Request No. 04.01.

The reports for Electric and Gas operations for the twelve months ended December 31, 2014, are included in the March 31, 2015 Commission Basis Reports ("CBR") filed under PSE Docket numbers UE-150528 and UG-150529. The reports provided under this filing are attached as Attachment C to PSE's response to H.Gil Peach & Associates Data Request No. 04.01

b. The decoupling rate plan approved in Order 07 of UE-121697, et al., provides incentives for PSE to cut costs primarily in the way the escalation or "K" factors were developed. On page 74, section 171 of Order 07, WUTC states, "The escalation factors provide PSE an improved opportunity to earn its authorized return, but are set at levels that will require PSE to improve the efficiency of its operations if it is to actually earn its authorized return." The escalation factors PSE used in developing the approved decoupling rate plan, three percent for Electric operations and 2.2 percent for Gas operations, are conservative when compared to a five year history of PSE's costs which supported escalation factors in the range of four percent for both Electric and Gas operations. Additionally, when developing the factors for Operations and Maintenance, Administrative & General expenses and Customer Service, PSE relied on the forecasted average Consumer Price Index ("CPI") for the 2013 to 2015 period less a one-half percent productivity factor. It follows that PSE will be required to increase efficiency of its operations if its authorized return is to be achieved.

c. PSE has implemented operational efficiencies in a way to avoid adverse impacts on customer service. In 2013, PSE met eight of nine Service Quality Indices ("SQIs") mandated by the WUTC. The one SQI that PSE did not meet in 2013 was SQI #5 Customer Access Center answering performance which was negatively impacted by PSE's implementation of a new Customer Information System, CIS, in the second and third quarters of 2013. During 2014 PSE met all nine of the Service Quality Indices for the year.

Responses to Second Year Data Requests

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.07

"CONFIDENTIAL" Table of Contents

DR NO.	"CONFIDENTIAL" Material
20.07	The ______________ to PSE's Response to Gil Peach & Associates (3rd Party Review) Data Request No. 20.07 is CONFIDENTIAL/HIGHLY CONFIDENTIAL per Protective Order in WUTC Docket Nos. UE-121697 and UG-121705.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.08

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.08:

Task Element 1: Calculation of Rates and Deferrals

Please provide an explanation and/or any material available that illustrate the review of PSE's decoupling rate calculations and the ongoing review of the associated revenue deferrals impacting its financial statements. This is an update of DR 01.38 submitted for the first year evaluation. Please provide an update of the information provided in response to **DR 01.38** including Attachments A, B, and C. The update should include information for the period July 2014 – June 2015 and through the last complete month when responding to this DR.

Response:

Attachments A and B to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 01.38 continue to be the current accounting instructions used to guide the implementation, tracking and ongoing review of PSE's electric and gas decoupling mechanisms. Attached as Attachment A to PSE's Response to H. Gil Peach & Associates Data Request No. 20.08 please find an updated auditor's report for PSE's 2014 financial statements, which is similar to that provided as Attachment C to PSE's Response to H. Gil Peach & Associates Data Request No. 01.38.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.09

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.09:

Task Element 3: Impact on Low Income Customers

Please describe any changes to the formula for determining the energy assistance for a client, if any, plus the date of each change through the last complete month when responding to this DR. This is a follow-up question **DR 01.14**

Response:

For Puget Sound Energy, Inc.'s ("PSE") Low Income Assistance program, there are no changes.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy, Inc. and NW Energy Coalition
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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.14

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.14:

One of the team's tasks is to complete an examination of whether and how the change to rate design for Schedule 26 and 31 affects conservation achievement by these customers. The evaluation will examine whether there is conclusive evidence that the change had an appreciable effect on customers' energy efficiency achievements, including but not limited to achievements made through customer participation in PSE's energy efficiency program. The part about what these customers achieve outside of PSE's programs appears to require information that may or may not currently exist, and might require contact with and discussions with a sampling of the customers. However, we note that in the Statement of Work, "the consultant is expected to rely primarily on existing data from PSE". Will PSE have data on what these customers are accomplishing outside PSE programs or is that information we will have to gather from the customers?

Response:

Puget Sound Energy, Inc. ("PSE") provides this response to data request 20.14 in a format that updates the data provided in its response to data request 1.25 of this evaluation. Attachment A provides conservation project information for the time period of July 1, 2014 through June 30, 2015. In addition to the summary query results, the workbook also contains the complete set of project data, providing the Evaluator the ability to perform additional lookups and filtering of data if desired.

As suggested by the evaluator's question, it isn't possible for PSE to report on customer efficiency activity outside of its conservation programs. Additionally, it isn't possible to directly attribute conservation savings variability to the effects of rate design changes due to a number of reasons, including but not limited to:

(1) Although the data in Attachment A of DR 20.14 reveals a reduction of savings for the updated time period, relative to the immediately previous time period for these specific Rate Schedules, a sizeable portion of the reduction can be attributed to Energy Efficiency's Industrial System Optimization Program's (ISOP's) operational cycle.

The majority of savings from this program occur between the last quarter and first quarter of each two-year cycle. Therefore, approximately 13 million kWh of conservation was achieved between November 2013 and April 2014; this is colloquially referenced as the "hockey stick" effect. For the same time period a year later, approximately 1.5 million kWh was achieved; the majority of the savings for the second of the two-year cycle has not yet been achieved. The data extracted for this specific data request (July 1, 2014 through June 30, 2015) is not only outside of the "hockey stick" effect of the program's two-year cycle, but also reflects the saturation of savings achieved in the first half of the program's cycle.

PSE estimates that a reduction of approximately 11.5 million kWh from the previously-reported timeframe can be attributed to the ISOP program's cyclical, and predictable, nature.

(2) Furthermore, the nature of industrial conservation projects in general is quite cyclical and projects are long-term; some are planned over a period of two years. This also leads to the overall savings for this block of customers varying substantially from one year to the next, as evidenced when comparing the data provide in the response to DR 01.25.

(3) Lastly, customers in these Rate Schedules may also shift from one Schedule to another, depending on their business needs/demand requirements.

Each of these conditions make it very difficult to attribute savings changes from one year to the next to a specific driver.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.15

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.15:

Please provide program targets and budgets for 2015. This is an update of DR 01.21

Response:

Included as Attachment A is Puget Sound Energy's ("PSE") 2015 Energy Efficiency savings targets and budgets, represented as the 2015 Annual Conservation Plan Exhibit 1, Portfolio View.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.17

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.17:

Since completing the response to DR 01.20, have client eligibility rules changed? Have there been changes in the levels of funding, and, if so, for which programs? Have there been changes in the level of services or measures provided?

Response:

No. Puget Sound Energy, Inc. ("PSE") continues to defer to the Washington State Department of Commerce on issues related to client eligibility. For changes in funding, please reference PSE's Response to H. Gil Peach & Associates Data Request No. 02.39. The fundamental structure of the Residential Low Income program has remained the same.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.19

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.19:

Information on dates and changes in senior management roles as they relate to energy efficiency has been provided for the first Evaluation Year. Please update such changes (if any) for the second Evaluation Year.

Response:

There have been no changes in Energy Efficiency senior management roles subsequent to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associated Data Request No. 01.22.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.21

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.21:

As a follow up to DR 01.24, is the company aware of any unanticipated side effects that are associated with the decoupling mechanisms? If so, please explain. In responding, please provide an update for the service quality standards (SQI) and reliability standards mandated by the WUTC.

Response:

Puget Sound Energy, Inc. ("PSE") is not aware of any unanticipated side effects associated with its decoupling mechanism. As noted in PSE's Response to H. Gil Peach & Associates Data Request No. 01.24, one often noted concern with decoupling is the potential for degradation in service quality and PSE has operated for many years under a series of service quality indices ("SQI") and reliability standards mandated by the Washington Utilities and Transportation Commission ("WUTC") that have financial penalties for failure to achieve minimum criteria.

As an update to PSE's Response to H. Gil Peach & Associates Data Request No. 01.24, please find attached as Attachment A to PSE's Response to H. Gil Peach & Associates Data Request No. 20.21 an Adobe PDF copy of PSE's SQI and Electric Reliability Reports to the WUTC for the year 2014.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.22

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.22:

Please provide any data on second Evaluation Year conservation accomplishments on conservation achievement by customers in its programs, updating the response to DR 01.25. Also, information, if available or on what conservation customers are accomplishing outside PSE programs.

Response:

Please see Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 20.14, which updated the original data provided in PSE's Response to H. Gil Peach & Associates Data Request No. 01.25. As noted in the earlier response, PSE has no data for customer activity outside of its programs.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.29

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.29:

In the response to DR 1.37 a set of data points beginning in 2001 were developed to represent yearly average energy use by PSE's electric customers and by PSE's natural gas customers. Similar data series were provided for values of average residential price of electricity and for average residential price of natural gas. Please extend each of these series to the present.

Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s. ("PSE") Response to H. Gil Peach & Associates Data Request No. 20.29, please find a Microsoft Excel file that extends the series of data provided in PSE's Response to H. Gil Peach & Associates Data Request No. 01.37 to include 2014. Attachment A summarizes electric and gas service average residential usage and revenues for the years 2001 to 2014.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.31

<u>H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.31:</u>

If there has been a new IRP since 2013, please provide a link.

<u>Response:</u>

Below please find a link to Puget Sound Energy, Inc.'s ("PSE") 2015 Integrated Resource Plan:

http://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.37

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.37:

This is a repeat of DR 04.02 for current knowledge and perspective. Is there any evidence of cost control and improvement of operational efficiency associated with decoupling?

Response:

As reported in Puget Sound Energy, Inc.'s. ("PSE's") Response to H. Gil Peach Data Request No. 04.01, PSE has filed reports for both electric and gas operations on its actual operations and maintenance ("O&M") cost per customer for the twelve months ended June 30, 2014 and for the twelve months ended December 31, 2014. PSE also filed reports for both electric and gas operations on its actual O&M cost per customer for the twelve months ended June 30, 2015 as reported in PSE's Response to H. Gil Peach & Associates Data Request No. 20.36.

The reports demonstrate that PSE's annual average increase in O&M costs has declined when compared to the historical growth rate presented in the decoupling rate plan proceedings under Docket Nos. UE-121697, et al.

At the time of this writing, there are no other PSE reports that require updating.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.39

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.39:

Has there been any change in the PSE's funding for low-income weatherization or for low-income bill assistance during the first and second Evaluation Years? If so, when did the change(s) take place and what dollar amounts were involved?

Response:

According to pages 76-77 of Order 07 in Docket Nos. UE-121697 and UG-121705, and in reference to the Multi-Party Agreement, Puget Sound Energy, Inc. ("PSE") agreed to add $500,000 to its residential Low Income Weatherization ("LIW") electric program and $100,000 to its investor contribution, and to sustain that level of funding henceforth. PSE added $500,000 to the 2014 Schedule 201 Electric Program budget and $100,000 to its Schedule 201 investor contribution which is reflected in the chart below. PSE sustained this added funding in its 2015 Schedule 201 Electric Program budget and its Schedule 201 investor contribution, also reflected in the chart below.

Schedule 201 Budget Comparison: 2013 - 2015

LIW Program Classification	2013	2014	2015
Tariff Electric	$ 2,425,462	$ 3,098,684	$ 3,313,139
Tariff Gas	$ 301,309	$ 369,443	$ 268,098
Shareholder	$ 300,000	$ 400,000	$ 400,000

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.40

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.40:

Please explain the effect of WAC 480-109-100 (10), setting a cost-effectiveness limit of "1" on operations. In other words, how does this rule help or hinder operations?

Response:

WAC 480-109-100(10) provides utilities with the option of funding low-income conservation projects that have been deemed by implementing agencies (State-appointed entities allowed to install conservation measures in low-income dwelling units) to be cost-effective consistent with the Weatherization Manual, maintained by the Washington Department of Commerce.

The rule revision has no effect on the installation of prescriptive measures, and thus, has no effect on Low Income Weatherization ("LIW") electric conservation. However, as a result of the rule revision, Puget Sound Energy, Inc. ("PSE") may now fund projects that have been evaluated using the State-approved Targeted Retrofit Energy Analysis Tool ("TREAT"); a tool that allows agencies to customize conservation measures for a specific dwelling unit or other qualifying structure. If the model indicates that a project's Savings-to Investment Ratio is greater than 1.0, the project is considered cost-effective, and thus, eligible for funding.

PSE began compliance with the revised rule in June 2015, and by December 2015, had processed one project based on TREAT analysis projections. Thus, it isn't possible to make a determination at this time as to the overall effect on program operations.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.44

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.44:

We understand that rate redesign and the decoupling mechanism became effective at the same time. Please provide a chart showing the change in dollars per kWh and kW due to rate design and the decoupling adjustment broken out separately for Schedule 26 and Schedule 31. Please provide this information for one year prior to decoupling and each year thereafter to current rates with effective dates. Also please include the relative tariffs documenting these rates and effective dates.)

Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s. ("PSE") Response to H. Gil Peach & Associates Data Request No. 20.44, please find a Microsoft Excel file that contains a summary of the kWh and KW rates for rate schedules 26 & 31 from May 14, 2012 to present. Please note that when the decoupling mechanism took effect on July 1, 2013, schedules 26 & 31 were originally decoupled using the kWh charge. On January 1, 2014, the rates were redesigned and from that point forward schedules 26 & 31 were decoupled using the KW charge.

Attached as Attachment B to PSE's Response to H. Gil Peach & Associates Data Request No. 20.44, please find the tariffs for schedule 26 that contain the rates that were in effect from May 14, 2012 to present.

Attached as Attachment C to PSE's Response to H. Gil Peach & Associates Data Request No. 20.44, please find the tariffs for schedule 31 that contain the rates that were in effect from May 14, 2012 to present.

Attached as Attachment D to PSE's Response to H. Gil Peach & Associates Data Request No. 20.44, please find the tariffs for schedule 142 that contain the rates for schedules 26 & 31 that were in effect from July 1, 2013 to present.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.45

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.45:

Please provide the source documents and page numbers or link to same for the market potential referenced in Table 1 of the draft Task 7 discussion (attached).

Response:

The below links are to Puget Sound Energy, Inc.'s ("PSE") 2013 Integrated Resource Plan ("IRP") documents that provide background and analyses that lead to the development of PSE's Demand-Side Management ("DSM") conservation potential.

2013 IRP Chapter 5: Electric Analysis:
http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chap5.pdf

2013 IRP Chapter 6: Natural Gas Analysis:
http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chap6.pdf

PSE's 2014-2015 conservation guidance was based on PSE resource planning models that use the information provided by The Cadmus Group, Inc. to derive cost-effective electric and natural gas conservation scenarios for the ten-year conservation potential and the 2014-2015 conservation target.

The information provided by The Cadmus Group, Inc. is included in the 2013 IRP Appendix N, available at this link:

http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppN.pdf

Additional information on how PSE uses the IRP guidance to establish its ten-year conservation potential and two-year conservation targets is provided in the attached 2014-2015 Biennial Conservation Plan Exhibit i: *2014-2023 Ten-year Conservation Potential and 2014-2015 Two-year Electric Target*. This document is attached as Attachment A to PSE's Response to H. Gil Peach & Associates Data Response No. 20.45.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.49

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 02.49:

Please provide values and calculation method and data for cost of conserved energy in units of measure conventionally used by PSE for low-income weatherization, non-low-income residential programs, and for the overall conservation effort except for low-income weatherization for electricity and gas for the years 2011 through 2015. It is OK to either specify calculation method and units along with appropriate source data or to go ahead and show calculation and results.

Response:

Based on further clarification from H. Gil Peach & Associates, Puget Sound Energy ("PSE") understands this request to be for tables that indicate a ratio comparing budgeted dollars to savings (electric and natural gas) goals versus actual expenditures compared to actual electric and natural gas savings for the indicated years, for the indicated Sector comparisons.

Attached as Attachment A to PSE's Response to H. Gil Peach & Associates Data Request No. 02.49, please find an MS Excel spreadsheet that provides those tables and ratios.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.52

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.52:

DR 20.52 Here is Table 37 from the draft report:

Conservation Rider: Electric Budget

Year	Residential	Business	Regional Efforts	Support	Pilots	Other Electric Programs	EES Research & Compliance	Total	% Change in Total Budget	MWh Goal	MWh Saved
2011	$32,965,000	$46,434,000	$5,261,000	$4,619,000	$ -	$ 1,516,000	$ -	$90,795,000		340,119	348,926
2012	$42,698,000	$41,871,000	$5,573,000	$3,514,000	$ -	$ 1,648,000	$ 3,172,000	$98,476,000	8.46%	336,600	339,500
2013	$42,477,000	$38,522,000	$5,261,000	$3,568,000	$ -	$ 835,000	$ 3,738,000	$94,401,000	-4.14%	333,520	361,400
2014	$45,105,000	$36,638,496	$5,260,640	$3,358,605	$1,572,459	$ 399,763	$ 3,485,575	$95,820,538	1.50%	344,405	378,500
2015	$47,674,312	$32,672,929	$4,771,922	$5,575,677	$1,267,712	$ 3,638,342	$ 3,806,632	$99,407,526	3.74%	277,605	

Note: For a complete representation of PSE's annual conservation savings and expenditures by program, please see Appendix 1. Appendix 1 is an extract of PSE's "Exhibit 1: Savings and Expenditures" from its Annual Report of Energy Conservation Accomplishments.

Are there any NEEA savings included in this table, and, if so, where?

Response:

NEEA savings are included in both the "MWh Goal" and "MWh Saved" totals as part of the overall Energy Efficiency portfolio for each year presented in Table 37.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.55

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.55:

A comment received on the draft report is that it does not mention that in May 2015, in the Schedule 142 natural gas rate adjustment filing the 3% "soft cap" was reached for residential customers.

A. Please provide a copy of the text or provide an explanation that describes the "soft cap" and how it is supposed to operate.
B. How meaningful is the selection of 3% and on what was the selection based? For example, why not 5% or 7% or 2%?
C. How does PSE perceive reaching the "soft cap" (does it mark a significant event or is it just the normal working of the mechanism, or both?).
D. The "soft cap" appears to be a simple "control tool" built into the decoupling mechanism. Does the decoupling mechanism contain any other control tools to limit the operation of decoupling?
E. What adjustment happens when the "soft cap" is reached for a COS Class, and how does this affect the earnings mechanism, ongoing?

Response:

A. The "soft cap," also referred to as the "Rate Test," for Puget Sound Energy's ("PSE") electric decoupling mechanisms is described in Section 10 of Exhibit No. JAP-9 in these dockets. The corresponding explanation of the parallel cap in the gas decoupling mechanism is provided in Section 10 of Exhibit No. JAP-10 in these dockets. These exhibits are provided as Attachment A to Puget Sound Energy's ("PSE") Response to H. Gil Peach & Associates Data Request No. 20.55.

B. There was no specific basis for setting the soft cap at 3.0 percent. It was a negotiated amount.

C. The "soft cap" has become a more significant event than originally contemplated with originally proposed as part of these mechanisms. According to Generally Accepted Accounting Principles (GAAP), PSE cannot recognize revenue that is not expected to be recovered within a 24 month period. At the time the soft cap was proposed for the decoupling mechanisms, PSE did not envision the large amount of deferred revenue that would be subject to the soft cap. Based on the GAAP revenue recognition guidelines, and given the significant level of deferrals that have been accrued, PSE has had to write down its revenues (for GAAP purposes) by $8.2 million for gas operations and $1.9 million for electric operations in 2015. While this revenue will be recognized later, when it is expected to be recovered within a 24 month period, it has reduced recognized revenue for GAAP purposes.

D. The decoupling mechanisms also contain an Earnings Test, which limits the amount of revenue that can be recovered by PSE under specified situations. With one exception, the operation of this feature of the mechanisms is explained in Section 10 of Exhibit Nos. JAP-9 and JAP10, both of which were provided in Attachment A to this response. The exception to what is explained in these exhibits is that the Commission removed the 25 basis point "headroom" proposed for the Earnings Test. As a result, PSE returns 50 percent of its earnings in excess of its authorized return, not in excess of 25 percent above its authorized return as originally proposed.

E. The Earnings Test affects the operation of the soft cap, not the other way around. If PSE reaches the threshold for sharing revenue with customers under the Earnings Test, this amount is reduced from the rate impacts before determining whether the 3.0 percent soft cap threshold is reached. See Part A to this response for more explanation.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.57

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.57:

In the current draft report, on or after Page 10, there is a statement that:

> The spike in all classes in December 2014 is a one-time rate credit for net proceeds from the sale of electric facilities in Jefferson County to Jefferson PUD. This caused revenue in each class to fall and the percentage due to Schedule 142 to increase.

A. Is this statement correct?
B. Public Counsel suggests that this credit was provided from shareholders. Is that correct?
C. Public Counsel suggests that if the credit was provided from shareholders there should not be any impact on Schedule 142 (due to this one-time credit). Is this correct?
D. Please, in general, clarify the treatment of the credit and its proper effect on Schedule 142 for December 2014.

Response:

A. Puget Sound Energy ("PSE") suggests inserting the word "due to" between the words "is" and "a" in the noted sentence. Otherwise, the statement is correct.

B. PSE does not agree with Public Counsel's interpretation. The proceeds that were paid to PSE customers came from Jefferson PUD, not PSE shareholders.

C. It is correct to conclude that the rate credit provided in connection with PSE's sale of electric facilities to Jefferson PUD did not impact the calculation of Schedule 142 rates. However, again, this was not paid by PSE shareholders.

D. The rate credit related to the sale to Jefferson PUD was temporary (one month) and significant ($29.12 for a residential customer using 1,000 kWh in the month of December 2014 relative to a bill that would have otherwise been over $90 for that month). The context provided by the report for this credit and its impact on the Schedule 142 rate impact calculations is appropriate.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 20.58

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 20.58:

A comment was received questioning the statement in the current draft report that for the two years studied "For natural gas, the impacts by COS class are so small as to be unremarkable (actual energy use was almost 'right on' predicted use."

A. The comment is: "That statement is surprising, because our understanding, from the May 2015 Schedule 142 rate adjustment filing, was that actual natural gas usage was below projected levels, resulting in fairly substantial under-recovery, particularly for the residential class." If we look at Tables 7 and 8 for natural gas in the draft report, we see that the monthly values are almost all "right on" with the highest monthly values being 3% and 2.7% but most being on the order of 0.03% or 1.7% or the like, and some values are positive and others negative:

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
Residential												
Usage (Therms)	17	18	25	66	92	134	120	114	87	58	32	24
Billed revenue	$ 28.72	$ 29.13	$ 36.77	$ 78.29	$ 105.80	$ 149.63	$ 135.52	$ 129.32	$ 101.38	$ 71.14	$ 44.14	$ 35.42
Schedule 142 billed revenue	$ 0.36	$ 0.37	$ 0.53	$ 1.39	$ 1.94	$ 2.82	$ 2.52	$ 2.39	$ 1.82	$ 1.21	$ 0.17	$ 0.16
Percent of average monthly bill	1.3%	1.3%	1.5%	1.8%	1.8%	1.9%	1.9%	1.8%	1.8%	1.7%	0.4%	0.5%
Commercial & Industrial Class												
Usage (Therms)	140	132	150	288	408	600	502	571	410	291	233	116
Billed revenue	$ 169.74	$ 160.30	$ 176.43	$ 304.50	$ 419.55	$ 603.78	$ 513.53	$ 577.03	$ 430.33	$ 314.25	$ 265.52	$ 153.66
Schedule 142 billed revenue	$ (0.55)	$ (0.52)	$ (0.59)	$ (1.13)	$ (1.61)	$ (2.36)	$ (1.98)	$ (2.25)	$ (1.62)	$ (1.15)	$ 5.26	$ 2.70
Percent of average monthly bill	-0.3%	-0.3%	-0.3%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	2.0%	1.8%
Large Volume Class												
Usage (Therms)	3,088	1,543	4,500	4,467	5,359	7,287	6,162	6,944	5,452	4,930	3,694	3,552
Billed revenue	$ 2,470	$ 668	$ 4,062	$ 3,167	$ 3,737	$ 4,947	$ 4,312	$ 4,638	$ 3,834	$ 3,479	$ 2,770	$ 2,825
Schedule 142 billed revenue	$ (7)	$ (3)	$ (10)	$ (8)	$ (10)	$ (13)	$ (11)	$ (12)	$ (10)	$ (9)	$ 30	$ 52
Percent of average monthly bill	-0.3%	-0.4%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	1.1%	1.8%
Interruptible Class												
Usage (Therms)	54,289	48,319	47,640	64,778	61,720	70,509	60,459	64,733	66,481	60,296	48,473	64,908
Billed revenue	$ 11,921	$ 9,117	$ 7,793	$ 11,729	$ 13,727	$ 19,165	$ 10,175	$ 14,646	$ 15,325	$ 10,954	$ 7,155	$ 12,737
Schedule 142 billed revenue	$ (57)	$ (50)	$ (49)	$ (63)	$ (63)	$ (67)	$ 221	$ 235	$ 253	$ 218	$ 216	$ 263
Percent of average monthly bill	-0.5%	-0.6%	-0.6%	-0.5%	-0.5%	-0.4%	2.2%	1.6%	1.6%	2.0%	3.0%	2.1%
Limited Interruptible Class												
Usage (Therms)	1,121	870	992	2,996	3,269	6,336	4,986	4,826	4,346	3,353	1,928	1,447
Billed revenue	$ 1,102	$ 849	$ 1,005	$ 2,322	$ 2,573	$ 4,691	$ 3,789	$ 3,639	$ 3,315	$ 2,645	$ 1,551	$ 1,274
Schedule 142 billed revenue	$ (3)	$ (2)	$ (3)	$ (7)	$ (7)	$ (13)	$ (10)	$ (10)	$ (9)	$ (7)	$ 21	$ 21
Percent of average monthly bill	-0.2%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	1.4%	1.6%
Non-Exclusive Interruptible Class												
Usage (Therms)	521,631	439,863	543,684	552,371	488,998	643,503	575,179	559,890	503,685	428,240	341,021	586,076
Billed revenue	$ 81,478	$ 50,439	$ 62,773	$ 72,223	$ 91,938	$ 141,670	$ 118,039	$ 108,543	$ 85,406	$ 54,392	$ 74,704	$ 74,189
Schedule 142 billed revenue	$ (292)	$ (228)	$ (265)	$ (266)	$ (255)	$ (297)	$ 973	$ 873	$ 867	$ 766	$ 857	$ 1,034
Percent of average monthly bill	-0.4%	-0.5%	-0.4%	-0.4%	-0.3%	-0.2%	0.8%	0.8%	1.0%	1.4%	1.1%	1.4%

	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
Residential												
Usage (Therms)	18	16	20	37	94	106	101	75	70	59	31	19
Billed revenue	$ 29.40	$ 27.82	$ 31.66	$ 48.52	$ 108.39	$ 122.82	$ 118.43	$ 90.90	$ 85.60	$ 73.35	$ 45.86	$ 31.90
Schedule 142 billed revenue	$ 0.12	$ 0.11	$ 0.14	$ 0.25	$ 0.64	$ 0.72	$ 0.69	$ 0.51	$ 0.48	$ 0.40	$ 1.24	$ 0.75
Percent of average monthly bill	0.4%	0.4%	0.4%	0.5%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	2.7%	2.3%
Commercial & Industrial Class												
Usage (Therms)	134	132	138	193	431	477	463	357	340	289	200	139
Billed revenue	$ 168.84	$ 165.68	$ 171.67	$ 224.51	$ 463.92	$ 519.01	$ 508.91	$ 402.26	$ 382.59	$ 329.04	$ 242.02	$ 180.07
Schedule 142 billed revenue	$ 3.10	$ 3.06	$ 3.19	$ 4.48	$ 10.00	$ 11.07	$ 10.75	$ 8.30	$ 7.88	$ 6.70	$ 6.06	$ 4.21
Percent of average monthly bill	1.8%	1.8%	1.9%	2.0%	2.2%	2.1%	2.1%	2.1%	2.1%	2.0%	2.5%	2.3%
Large Volume Class												
Usage (Therms)	3,012	3,144	3,008	3,674	6,098	4,962	5,573	4,330	5,567	5,000	4,169	3,351
Billed revenue	$ 2,381	$ 2,511	$ 2,365	$ 2,803	$ 4,364	$ 3,752	$ 4,148	$ 3,278	$ 4,190	$ 3,772	$ 3,176	$ 2,640
Schedule 142 billed revenue	$ 46	$ 49	$ 45	$ 51	$ 72	$ 63	$ 69	$ 56	$ 70	$ 65	$ 71	$ 63
Percent of average monthly bill	1.9%	1.9%	1.9%	1.8%	1.6%	1.7%	1.7%	1.7%	1.7%	1.7%	2.2%	2.4%
Interruptible Class												
Usage (Therms)	49,555	52,304	56,325	59,599	65,854	62,761	53,101	58,728	68,616	61,284	57,059	54,146
Billed revenue	$ 7,897	$ 8,805	$ 10,447	$ 11,310	$ 14,362	$ 13,843	$ 7,514	$ 12,942	$ 17,347	$ 13,656	$ 13,164	$ 11,135
Schedule 142 billed revenue	$ 231	$ 191	$ 234	$ 238	$ 250	$ 273	$ 311	$ 355	$ 401	$ 363	$ 327	$ 324
Percent of average monthly bill	2.9%	2.2%	2.2%	2.1%	1.7%	2.0%	4.1%	2.7%	2.3%	2.7%	2.5%	2.9%
Limited Interruptible Class												
Usage (Therms)	1,005	855	1,043	2,059	3,875	4,258	4,262	4,192	3,574	3,911	1,645	1,308
Billed revenue	$ 952	$ 830	$ 1,045	$ 1,722	$ 3,121	$ 3,533	$ 3,519	$ 3,405	$ 2,973	$ 3,200	$ 1,499	$ 1,225
Schedule 142 billed revenue	$ 16	$ 13	$ 16	$ 29	$ 50	$ 55	$ 54	$ 53	$ 46	$ 50	$ 30	$ 25
Percent of average monthly bill	1.6%	1.6%	1.6%	1.7%	1.6%	1.6%	1.5%	1.6%	1.6%	1.6%	2.0%	2.0%
Non-Exclusive Interruptible Class												
Usage (Therms)	414,081	411,503	384,006	434,724	470,789	604,624	525,033	542,878	633,374	577,564	588,180	568,238
Billed revenue	$ 52,967	$ 59,694	$ 49,468	$ 71,494	$ 68,876	$ 132,541	$ 91,009	$ 90,017	$ 82,093	$ 101,313	$ 79,488	$ 98,013
Schedule 142 billed revenue	$ 784	$ 844	$ 770	$ 865	$ 845	$ 1,125	$ 1,171	$ 1,101	$ 1,565	$ 1,530	$ 1,480	$ 1,480
Percent of average monthly bill	1.5%	1.4%	1.6%	1.2%	1.2%	0.8%	1.3%	1.2%	1.9%	1.5%	1.9%	1.5%

To a practicing applied statistician, variation of the kind shown in these tables is quite small, especially for energy data which tends to have large standard deviations and standard errors. The percentages are based on projected energy use. Then, adjustments are made on the basis of projections that can be one, two, or three years into the future based on knowledge developed in the planning phase for decoupling. Given these considerations, the data seem *exceptionally well behaved.* Since the "soft caps" are set at 3%, it would seem that 3% has been selected as some kind of a meaningful threshold value. Looking at these tables, and given that variation is expected to occur in monthly data series, would PSE agree that the data (considering all of the months over two years for a COS Class) are almost "right on" or well behaved?

B. Can the data be well-behaved as a data series in a statistical sense and also result (over 12 months) in "fairly substantial under recovery, particularly for the residential class"?

C. Does PSE see the May 15 adjustment filing to reflect "substantial under-recovery"? And, either way, isn't this just the normal mathematics of the mechanism at work?

D. Please provide a cut-off or a range at which a monthly percentage value or a subset of monthly percentage values might be of concern. In other words, please express a sensitivity for calibration of the monthly values in the even that they become not well-behaved.

Response:

A. The data speaks for itself. Whether it is "right on" or "well behaved" in relation to expectations is in the eye of the beholder. However, it is correctly noted that nearly all of these percentages fall below the 3.0 percent threshold used in the mechanisms' Rate Test.

B. The data presented in the tables above speak to the current recovery of costs through Schedule 142 rates in relation to the overall customer bill. However, these values do not illustrate whether PSE is recovering its authorized revenue, which is generally determined by multiplying the monthly allowed revenue per customer by the number of customers being served in each decoupling rate group. It is the difference between the actual revenue collected (through base and Schedule 142 rates) and allowed revenue that must be trued up in each Schedule 142 filing. Therefore, the level and direction of monthly deferrals are a good indication of whether the utility is fully recovering its costs in any given month.

C. Again, the data speaks for itself. The May 1, 2015 Schedule 142 gas decoupling rates reflect the recovery of nearly $18 million in deferred revenue in 2014, with the electric decoupling rates recovering $15 million in deferred revenue in 2014. Whether this is "substantial" or not is in the eye of the beholder. However, as noted, this was how the mechanism was contemplated to work, with the differences between actual and allowed delivery revenue from each calendar year being trued up beginning on May 1 of the following year (subject to the Rate Test and Earnings Test). That being said, through the application of the Rate Test, approximately $8 million in additional gas residential deferred revenue and $2 million in additional electric non-residential (Schedules 10 and 31) deferred revenue was not set into rates on May 1, 2015. It is expected that these additional amounts will be recovered beginning May 1, 2016.

D. As noted, by application of the mechanisms' Rate Test, annual average decoupling-related rate impacts are limited to 3.0 percent per year. Therefore, this is the limit for which these impacts will be felt in any particular year.

Responses to Three Year Data Requests

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.07

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.07:

Task Element 1: Calculation of Rates and Deferrals

Please provide copies of the “Decoupling Work-papers and Spread-Sheets” used to calculate the rates and deferrals including: tariff tracker adjustments, deferrals, (k) factor adjustments, and allowable revenue. This is an update of DR 20.07 submitted for the second year evaluation and DR 01.05 submitted for the first year evaluation. Updated data should cover the period July 2015 – June 2016, through the most recent month for which complete data is available when responding to this DR.

Response:

Attached as Attachment A to Puget Sound Energy, Inc.’s. (“PSE”) Response to H. Gil Peach & Associates Data Request No. 30.07, please find a Microsoft Excel file that calculates the decoupling deferrals for the time period July 2013 through June 2016. Please note that this file represents restated results for corrections and commission approved changes to the mechanism.

Attached as Attachments B and C to PSE’s Response to H. Gil Peach & Associates Data Request No. 30.07 please find Microsoft Excel files that calculate the electric and gas decoupling rates, respectively, effective May 1, 2016.

For Rates in effect on July 1, 2015 please see PSE’s Response to H. Gil Peach & Associates Data Request No. 20.07.

Attachments B and C to PSE’s Response to H. Gil Peach & Associates Data Request No. 20.07 are Microsoft Excel files that calculated changes to the electric and gas decoupling rates, respectively, effective May 1, 2015.

Due to its large size, Attachment A, B and C to PSE’s Response to H. Gil Peach & Associates Data Request No. 30.07 are submitted in electronic format only.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.08

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.08:

Task Element 1: Calculation of Rates and Deferrals

Please provide an explanation and/or any material available that illustrate the review of PSE's decoupling rate calculations and the ongoing review of the associated revenue deferrals impacting it financial statements. This is an update of DR 20.08 submitted for the year 2 evaluation and DR 01.38 submitted for the year 1 evaluation. Please provide an update of the information provided in response to DR 01.38 including Attachments A, B, and C. The update should include information for the period July 2015 – June 2016 and through the last complete month when responding to this DR.

If any information provided in response to DR 20.08 or DR 01.38 has been revised, please note the changes (if any). If there have been no changes to information provided in responses these DRs, please state that there have been no changes.

Response:

Attachments A and B to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 01.38 continue to be the current accounting instructions used to guide the implementation, tracking and ongoing review of PSE's electric and gas decoupling mechanisms. Attached as Attachment A to PSE's Response to H. Gil Peach & Associates Data Request No. 30.08 please find an updated auditor's report for PSE's 2015 financial statements, which is similar to that provided as Attachment C and A to PSE's Responses to H. Gil Peach & Associates Data Request Nos. 01.38 and 20.08 respectively.

There have been no changes to the information provided in response to H. Gil Peach & Associates Data Request Nos. 01.38 and 20.08.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.10

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.10:

Task Element 3: Impact on Low Income Customers

Please provide a description of any changes in how the low income programs are operated during the period July 2015 – June 2016 and through the last complete month for which data is available when responding to this DR. This is an update of second year DR 20.10 and first year DR 01.15.

Response:

For Energy Efficiency's Low Income Weatherization program, there has been no significant change to the policies and program structure governing the program during the period of July 2015 – June 2016 and through the last complete month for which data is available.

From an implementation perspective, one agency in the Puget Sound Energy ("PSE") gas service territory decided to terminate its agreement with PSE to focus their production on spending electric dollars. That has reduced total number of Agency Agreements from 10 to 9. The agency found there was more opportunity to serve low income electric customers because 1) many low income customers have electricity as their primary fuel source; and, 2) gas incentives are lower compared to electric and it was harder to spend and leverage PSE dollars on gas heated homes. Therefore, they made the decision to focus production on electrically heated homes.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.11

<u>H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.11:</u>

Task Element 3: Impact on Low Income Customers

Please provide and updated (including date for the most recent complete month) summary of the annual deferrals and rate impacts of the decoupling tariff tracker adjustments (cents per KWh, cents per therm, total dollars and percent of monthly bills) on the groups of customers receiving bill assistance through PSE's low-income programs vs. regular residential customers (from which low-income customers have been removed). This is an update of DR 20.11 and DR 01.16.

<u>Response:</u>

Attached as Attachment A to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 30.11, please find a Microsoft Excel file providing a summary of the annual deferrals and rate impacts of the decoupling tariff tracker adjustments (cents per kWh, cents per therm, total dollars and percent of monthly bills) on the group of customers receiving bill assistance through PSE's low-income programs vs. regular residential customer (from which low-income customers have been removed) for the time period of July 2013 through June 2016.

A summary of the annual deferrals for the group of customers receiving bill assistance through PSE's low-income programs vs. regular residential customer (from which low-income customers have been removed) for the time period of July 2015 through June 2016 can be found in the worksheet titled "Deferral Summary Jul15-Jun16."

The rate impacts for the time period of July 2015 through June 2016 have been calculated separately for customers receiving bill assistance ("BA") and those receiving no bill assistance ("NBA"). These customers are defined consistently with PSE's Response to H. Gil Peach & Associates Data Request No. 01.09. These impacts can be found in the following worksheets titled:

- Electric Impacts BA Jul15-Jun16
- Electric Impacts NBA Jul15-Jun16
- Gas Impacts BA Jul15-Jun16
- Gas Impacts NBA Jul15-Jun16

Also contained in Attachment A is the same data as above for the time periods of July 2013 through June 2014 and July 2014 through June 2015. The data provided for these time periods has not changed from what was provided in Data Request No. 20.11.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.13

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.13:

Task Element 3: Impact on Low Income Customers

Please provide updates to the total low incomes grants and the number of customers receiving grants per month by grant type through the most recent complete month when responding to this DR. Please include most recent data in Attachment A to PSE's Response to H. Gil Peach & Associates DR 20.13 and DR 02.02.

If any information provided in response to these previous DRs has been revised, please note the changes (if any). If there have been no changes to information provided in responses these DRs, please state that there have been no changes.

Response:

Attached as Attachment A to Puget Sound Energy's ("PSE") Response to Gil Peach and Associates Data Request No. 30.13 is a MS Excel spreadsheet, highlighted in orange are updates to the total low incomes grants and the number of customers receiving grants per month by grant type through July 2016. There have been no changes to information provided in responses these previous Data Responses.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.14

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.14:

One of the team's tasks is to complete an examination of whether and how the change to rate design for Schedule 26 and 31 affects conservation achievement by these customers. The evaluation will examine whether there is conclusive evidence that the change had an appreciable effect on customers' energy efficiency achievements, including but not limited to achievements made through customer participation in PSE's energy efficiency program. The part about what these customers achieve outside of PSE's programs appears to require information that may or may not currently exist, and might require contact with and discussions with a sampling of the customers. However, we note that in the Statement of Work, "the consultant is expected to rely primarily on existing data from PSE". Will PSE have data on what these customers are accomplishing outside PSE programs or is that information we will have to gather from the customers? This is an update of DR 20.14.

Response:

Puget Sound Energy, Inc. ("PSE") provides this response to data request 30.14 in a format that updates the data provided in its response to data request 20.14 of this evaluation. Attachment A to H. Gil Peach & Associates Data Request No. 30.14 provides conservation project information for the time period of July 1, 2015 through June 30, 2016. In addition to the summary query results, the workbook also contains the complete set of project data, providing the Evaluator the ability to perform additional lookups and filtering of data if desired.

PSE confirms that it isn't possible for PSE to report on customer efficiency activity outside of its conservation programs. Additionally, it isn't possible to directly attribute conservation savings variability to the effects of decoupling due to Energy Efficiency's Industrial System Optimization Program's (ISOP's) operational cycle. The majority of savings from this program occur between the last quarter and first quarter of each two-year cycle.

Furthermore, the nature of industrial conservation projects in general is quite cyclical and projects are long-term; some are planned over a period of two years. This also leads to the overall savings for this block of customers varying substantially from one year to the next, as evidenced when comparing the data provide in the response to DR 01.25.

Lastly, customers in these Rate Schedules may also shift from one Schedule to another, depending on their business needs/demand requirements.

Each of these conditions make it very difficult to attribute savings changes from one year to the next to a specific driver.

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Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.15

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.15:

Please provide program targets and budgets for 2016. Also, please provide any changes or revisions to previous program targets and budgets previously provided, if any (or a statement that there are no such changes, if none). This is an update of DR 20.15.

Response:

Puget Sound Energy ("PSE") provides its 2016 Conservation savings goals and budgets ("Exhibit 1: 2016 Savings and Budgets") as Attachment A to H. Gil Peach & Associates Data Request No. 30.15. Savings targets and budgets previously provided have not changed.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.18

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.18:

Please provide program budgets for the third evaluation year. Please also provide any retrospective changes to program budgets for the two years prior to decoupling plus evaluation year one and evaluation year two (if any). If there have been no changes to information for these years, please state that there have been no changes. This is an update of DR 20.18

Response:

Attached as Attachment A to Puget Sound Energy Inc.'s ("PSE") response to H. Gil Peach & Associates Data Request No. 30.18 is the 2016 Exhibit 1: Savings and Budgets for 2016. None of the budgets previously provided changed retrospectively. It is important to note, relative to the term "evaluation year", that PSE budgets on a calendar year, rather than the time period indicated in "evaluation year".

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.19

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.19:

Please provide information on dates and changes in senior management roles as they relate to energy efficiency (if any) for the third Evaluation Year. This is an update of DR. 20.19.

Response:

In June, 2016, Jason Teller, vice-president of Customer Solutions resigned from Puget Sound Energy Inc. ("PSE"), and the director of Energy Efficiency, Bob Stolarski, now reports to Phil Bussey, senior vice-president of Customer Experience and Chief Customer Officer.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.20

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.20:

Please provide information on any energy efficiency and/or low-income presentations to the Board during the third Evaluation Year (for example, please provide any relevant minutes from Board meetings for this period. This is an update of DR 20.20.

Response:

There have been no Energy Efficiency or Low-Income presentations to the Puget Sound Energy Inc.'s ("PSE") board of directors subsequent to PSE's response to Gil Peach and Associates' Data Request ("DR") 20.20.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy, Inc. and NW Energy Coalition
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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.21

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.21:

As a follow-up to DR 01.24 and DR 20.21, is PSE aware of any unanticipated side effects that are associated with the decoupling mechanisms? If so, please explain. In responding, please also provide an update for the service quality standards (SQI) and reliability standards mandated by the WUTC for the third Evaluation Year.

Response:

Puget Sound Energy ("PSE") is not aware of any unanticipated side effects associated with its decoupling mechanism. As noted in PSE's Response to H. Gil Peach & Associates Data Request No. 01.24 and No. 20.21, one often noted concern with decoupling is the potential for degradation in service quality and PSE has operated for many years under a series of service quality indices ("SQI") and reliability standards mandated by the Washington Utilities and Transportation Commission ("WUTC") that have financial penalties for failure to achieve minimum criteria.

As an update to PSE's Response to H. Gil Peach & Associates Data Request No. 01.24 and No. 20.21, please find attached as Attachment A to PSE's Response to H. Gil Peach & Associates Data Request No. 30.21 an Adobe PDF copy of PSE's SQI and Electric Reliability Reports to the WUTC for the year 2015. Please also find attached as Attachment B to PSE's Response to H. Gil Peach & Associates Data Request No. 30.21 an Adobe PDF copy of PSE's semi-annual update to its SQI and Electric Reliability Reports for the first six months of 2016.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.29

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.29:

In the response to DR 1.37 and DR 20.29 a set of data points beginning in 2001 were developed to represent yearly average residential energy use by PSE's electric customers and by PSE's natural gas customers. Similar data series were provided for values of average residential price of electricity and for average residential price of natural gas. Please extend each of these series to the present. Please also provide the same data monthly for the months of October through March for the same timespan (beginning in 2001), plus a list of average monthly temperatures for the months of October through March for PSE service territory for this timespan (beginning in 2001).

Response:

Attached as Attachments A, B and C to Puget Sound Energy, Inc.'s. ("PSE") Response to H. Gil Peach & Associates Data Request No. 30.29, please find a Microsoft Excel file that extends the series of data provided in PSE's Response to H. Gil Peach & Associates Data Request Nos. 01.37 and 20.29 to include 2016.

Attachment A summarizes electric and gas service average residential usage and revenues for the years 2001 to 2015. Note: In 2014, the electric weather adjusted revenue ($1,102) has been revised to reflect the full impact of base revenue related to the usage adjustment. The 2014 version (DR 20.29) reflects only power cost related revenue ($1,094), reflective of what is reported in the commission basis reports, the source of the weather adjusted revenue data. In 2013 & 2014, the gas weather adjusted revenue ($976 & $954) has been revised to reflect the full impact of base revenue related to the usage adjustment. The 2014 version (DR 20.29) reflects margin related revenue ($964 & $913), reflective of what is reported in the commission basis reports, the source of the weather adjusted revenue data.

Attachment B summarizes electric and gas residential usage and revenues for the months of October through March, 2001 to 2016.

Attachment C summarizes average temperatures for the months of October through March, 2001 to 2016.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.36

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.36:

Please update DR 04.01 and DR 20.36 for any newer: Copy of each and every status report on cost-cutting; Explain how the rate plan provides incentives to PSE to cut costs in order to achieve its rate of return; Please explain if cost-cutting requires a reduction in levels of activity or service or if it does not for each cost-cutting activity adopted.

Response:

Cost per customer reports for electric and gas operations for the twelve months ended December 31, 2015, were included in the March 31, 2015 compliance filing under Docket Nos. UE-160375 and UG-160376. The report provided under this compliance filing is attached as Attachment A to Puget Sound Energy's ("PSE's") Response to H. Gil Peach & Associates Data Request No. 30.36.

At the time of this data request response, no other data concerning PSE's incentives to cut costs related to Docket Nos. UE-130137, UG-130138, UE-121697, et al. requires updating.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy and NW Energy Coalition
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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.37

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.37:

This is a repeat of DR 04.02 and DR 20.37 for current knowledge and perspective. Is there any evidence of cost control and/or improvement of operational efficiency associated with decoupling?

Response:

As reported in Puget Sound Energy's ("PSE's") Response to H. Gil Peach Data Request No. 04.01, PSE has filed reports for both electric and gas operations on its actual operations and maintenance ("O&M") cost per customer for the twelve months ended June 30, 2014 and for the twelve months ended December 31, 2014. PSE also filed reports for both electric and gas operations on its actual O&M cost per customer for the twelve months ended June 30, 2015 as reported in PSE's Response to H. Gil Peach & Associates Data Request No. 20.36 and for the twelve months ended December 31, 2015 as reported in PSE's Response to H. Gil Peach & Associates Data Request No. 30.36.

The reports demonstrate that PSE's annual average increase in O&M costs has declined when compared to the historical growth rate presented in the decoupling rate plan proceedings under Docket Nos. UE-121697, et al.

At the time of this writing, there are no other PSE reports that require updating.

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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.39

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.39:

Has there been any change in PSE's funding for low-income weatherization or for low-income bill assistance during the third Evaluation Year? If so, when did the change(s) take place and what dollar amounts were involved? Also please provide any retrospective changes in the previous response to DR 20.39 (if any). If there have been no changes to information previously provided for DR 20.39, please state that there have been no changes.

Response:

For the Puget Sound Energy Inc.'s ("PSE") Schedule 201 Residential Low Income Weatherization program, please refer to the budget comparison for the 2015 and 2016 programs presented in the response to H. Gil Peach and Associates Data Request No. 30.16.

Schedule 201 Budget Comparison: 2015-2016

	2015	2016
Sch 201 Electric	$ 3,318,139	$ 3,386,625
Sch 201 Gas	$ 268,098	$ 283,478
Investor Contribution	$ 400,000	$ 400,000

There has been a change in PSE's funding for low-income bill assistance during the third Evaluation Year. It is in the table below.

There have been no changes in the previous response to DR 20.39.

The following Schedule 129 Low Income bill assistance program changes occurred on 10/1 of 2015 and will on 10/1 2016 during the evaluation years

Schedule 129 Budget Comparison: 2015 - 2016

LI Program Classification	10/1/2015	10/1/2016	
Tariff Electric	$16,874,331	$17,955,769	
Tariff Gas	$ 5,569,428	$ 6,360,227	

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.42

"CONFIDENTIAL" Table of Contents

DR NO.	"CONFIDENTIAL" Material
30.42	The ______________ to PSE's Response to Gil Peach & Associates (3rd Party Review) Data Request No. 30.42 is CONFIDENTIAL/HIGHLY CONFIDENTIAL per Protective Order in WUTC Docket Nos. UE-121697 and UG-121705.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.43

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.43:

Please discuss any increase or decrease in low-income effort (separately for natural gas and electricity) from the beginning of decoupling through the end of Evaluation Year three. This is a follow-one request from DR 20.43.

Response:

Overall Puget Sound Energy Inc.'s ("PSE") Low Income Weatherization ("LIW") program effort has remained somewhat consistent. Some highlights are presented below.

Electric funding has gone up since the beginning of decoupling with the last two years (2014/15) remaining consistent. Overall Gas funding has gone down due to decreased gas production at the agency level.

PSE has implemented WAC 480109100(10) (please see PSE's response to H. Gil Peach and Associates Data Request No. 30.40). Effort of PSE Program staff has increased slightly due to additional administrative requirements associated with program implementation.

Multi Family Air Sealing requires additional effort by PSE staff and agencies since savings must be calculated on a custom basis per building treated.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.56

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.56:

Is there any change to PSE's response to DR 20.56 regarding the Schedule 142 "soft cap" of 3% for Schedule 10 (part of the electric Primary Voltage Class) and for Schedule 31 (part of the natural gas Commercial and Industrial Class)?

Response:

Again clarifying that the soft cap triggered for Puget Sound Energy's electric Schedule 31, not its gas Schedule 31, the company proposes no changes to its Response to H. Gil Peach & Associates Data Request No. 30.56.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.59

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.59:

Has PSE modeled recovery under alternative values of the "soft cap"? Since the selection of 3% was not grounded, it seems reasonable that a simulation of the situation of cap and deferral could iterate until an optimal solution as to size of cap (4%, 5%, etc. is found). If so, please provide the analysis.

Response:

Puget Sound Energy ("PSE") did not model alternative values of the soft cap which limits annual decoupling filing rate increases to no more than 3% ("Rate Test") at the time the decoupling mechanism was originally filed and approved by the Washington Utilities and Transportation Commission. At that time PSE did model decoupling deferrals, amortizations and rates using the 3% level for the Rate Test for the July 2013 through December 2015 period using forecasted customers and volumes and these exhibits were included in the compliance filings for electric and gas. These projections did not indicate any significant issues with rate increases exceeding the Rate Test at the 3% level.

However, in the annual decoupling rate filings since the decoupling mechanism took effect there have been three instances where the rate increase before the Rate Test exceeded 3%, please see PSE's response to H. Gil Peach & Associates Data Request No. 30.42 for more detail on these instances. Attached as Attachment A to PSE's Response to H. Gil Peach & Associates Data Request No. 30.59 is a table that summarizes the actual results of the Rate Test for each of the electric and gas decoupling groups for the 2014, 2015 and 2016 annual decoupling filings. The actual results show that the gas residential decoupling group is the primary decoupling group having significant issues with the Rate Test at the current 3% level.

Attached as Attachment B to PSE's Response to H. Gil Peach & Associates Data Request No. 30.59 is an analysis of the gas residential decoupling group to find what percent level of the Rate Test would have been needed to amortize all the deferrals in PSE's 2015, 2016 and projected 2017 annual decoupling filings. With a 5% cap in place for the Rate Test, PSE would have been able to amortize all of the decoupling deferrals in these annual filings for the gas residential decoupling group. The highest rate impact to customers using this size cap would have been a 4.79% increase to customers in the 2016 annual filing.

The back cast analysis indicates that a cap of 5% for the Rate Test for the gas residential decoupling group would solve the issue of deferrals remaining on PSE's balance sheet due to not being able to amortize these deferrals in the annual filings. This resolves the related problems associated with leaving deferral balances on the balance sheet including the Generally Accepted Accounting Practice issue regarding the recognition of current period revenue by ensuring the recovery of deferred decoupling-related revenue will occur within two years from when it was originally recognized. Secondly, this solves the potential intergenerational equity issues caused by the delay in timing between the incurrence of costs and the recovery of those cost in rates.

All of that said, while a 5% Rate Test would alleviate the issue of carrying a balance of deferred gas residential revenue, it also lessens the value of the protection that this test is intended to provide these customers (i.e., rate volatility). Therefore, the "optimal solution" is really a policy question as to how best to strike a balance between growing deferred balances and customers' rate volatility. Attempting to strike a balance, PSE believes that a Rate Test set between 4 and 5% may be appropriate.

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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.62

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.62:

PSE completed an analysis of the variation in actual and weather normalized use per customer relative to the ERF Test Year (Decoupling Groups Current vs Proposed UPC Analysis.xlsx). The analysis included evaluation years one (July 2013-Jume 2014) and two (July 2014-June 2015). Please update this analysis to include evaluation year three (July 2015-June 2016).

Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 30.62, please find a Microsoft Excel file that contains a summary of the actual and weather normalized use per customer by rate schedule relative to the ERF Test Year for evaluation years one, two and three.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.63

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.63:

Please provide updates to DR 30.13_Att A. Please provide data for the total low income assistance grants and the number of customers receiving grants per month by grant type for August and September of 2016.

Response:

Attached as Attachment A to Puget Sound Energy's response to Gil Peach Data Request No. 30.63 is the additional data for the total low income assistance grants and the number of customers receiving grants per month by grant type for August and September of 2016.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Puget Sound Energy, Inc. and NW Energy Coalition
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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.64

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.64:

For 2015, according to the 2015 Annual Puget Sound Energy Service Quality and Electric Service Reliability Report, at least four service quality indicators were out of range and therefore are problematic. These include (1) "Customer Access Center Answering Performance", (2) "Secondary Non-Emergency Safety Response and Restoration Time - Core Hour -- Quanta Electric," (3) "SAIFI(5%) <5% Non-Major Storm (< 5% customers affected)" and (4) "SAIDI (Total 5-Year Average) Total (all outages 5 year average)".

In looking through the write-ups on each of these service quality problems in the report, the common feature seems to be weather-related. The weather would, of course, occur with or without decoupling. At the same time, one of the critiques of decoupling is that it will cause the company to become less attentive or less motivated to provide customer service and so perhaps slow in response and possibly understaffed for the weather. Please explain why, for each of these indicators individually, the service quality problem was or was not in some way related to decoupling either as a direct cause or a remote cause.

Response:

(1) Customer Access Center Answering Performance:
The decoupling mechanism was not a direct or remote cause of the 2015 performance result. As shown on page 12 of the 2015 Annual Puget Sound Energy ("PSE") Service Quality and Electric Service Reliability Report ("Report"), the 2015 performance result was negatively affected by the circumstances related to changing collection and disconnection procedures, unseasonal storms in August, technology system failures, and staffing issues.

(2) Secondary Non-Emergency Safety Response and Restoration Time - Core Hour -- Quanta Electric:
The decoupling mechanism was not a direct or remote cause of the performance result. As indicated on page 24 of the Report, the 2015 performance result of 258 minutes was due to fewer available Quanta crews for the secondary incidents as more crews were assigned to emergency storm duty.

(3) $SAIFI_{5\%}$ <5% Non-Major Storm (< 5% customers affected) SAIFI:
PSE met the requirement of this measurement. PSE's performance of 1.11 interruptions per customer per year for this measurement is better than the benchmark of 1.30 interruptions, i.e., customers experienced, on average, 0.19 less interruptions than the benchmark.

(4) $SAIDI_{Total\ 5\text{-}Year\ Average}$ Total (all outages five-year average) SAIDI:
PSE met the requirement of this measurement with the approval of the Washington Utilities and Transportation Commission ("WUTC") to exclude the catastrophic storms that occurred in August and November 2015. The WUTC order providing the exclusion can be found at the following link:
https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=2074&year=2007&docketNumber=072300
PSE's customer report card with the final performance result of 272 minutes per customer per year can be found at:
http://pse.com/accountsandservices/NewToPSE/Documents/2774_SQI_Report_Card_2015_wb.pdf

As stated in PSE's Response to H. Gil Peach & Associates Data Request No. 30.21. PSE is not aware of any unanticipated side effects associated with its decoupling mechanism. In particular, PSE has not seen any side effects of the decoupling mechanism on its service quality or service reliability performance since the adoption of the decoupling mechanism in 2013.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.65

"CONFIDENTIAL" Table of Contents

DR NO.	"CONFIDENTIAL" Material
30.65	The ______________ to PSE's Response to Gil Peach & Associates (3rd Party Review) Data Request No. 30.65 is CONFIDENTIAL/HIGHLY CONFIDENTIAL per Protective Order in WUTC Docket Nos. UE-121697 and UG-121705.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.66

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.66:

Please provide any analysis conducted by Puget Sound Energy that decomposes the electric and natural gas rate impacts by rate schedule associated with its decoupling mechanisms, separate from the approved rate plan (i.e., K-factor) increases and any other relevant factors.

Response:

Please find attached as Attachment A to Puget Sound Energy, Inc. ("PSE") Response to H. Gil Peach Data Request No. 30.66 an MS Excel spreadsheet summarizing the rate impacts by rate schedule associated with PSE's electric and natural gas decoupling mechanism, approved rate plan and associated factors for the rate years beginning May 1, 2015 and May 1, 2016.

Specifically, the results presented in the columns titled "Deferral Amortization" in Attachment A present the impacts of PSE's decoupling mechanism absent the allowed revenue per customer increases associated with the rate plan, and other factors impacting the mechanism. These results show a "backcast" of the results that would have occurred had PSE implemented a more traditional decoupling mechanism that tied its allowed revenue per customer and actual rate revenue to test year levels. This test year for PSE's decoupling mechanisms is the period ending June 2012 in PSE's Expedited Rate Filing ("ERF"). This backcast produced deferred revenue that were then compared to actual total rate revenue to determine the rate impact shown in the columns titled "Deferral Amortization."

The columns titled "K-Factor" in Attachment A presents the impacts of the authorized rate plan increases to delivery revenue of 3% for electric and 2.2% for natural gas without the influence of forecasted customers and volumes and associated use per customer changes impacting revenue. The K-Factor revenues were calculated by multiplying the appropriate annual allowed revenue per customer for each year by ERF customer counts and then subtracting ERF level allowed revenue. The resulting K-Factor revenue was then compared to actual total rate revenue to determine the rate impacts shown.

The overall rate impact shown in the "Total Rate" columns of Attachment A tie to those presented in PSE's Response to H. Gil Peach Data Request Nos. 20.07 and 30.07. The difference between this overall impact and the sum of the "Deferral Amortization" and "K-Factor" impacts are included in the "Other" category in Attachment A. The factors that influence the level of this "other" impact include deviations between actual and forecasted customer and loads used to calculate Schedule 142 rates, timing differences between increases in allowed revenue per customer (i.e., January 1 of each year) and Schedule 142 rates (i.e., May 1 of each year) and the application of the 3% rate test that limits the overall rate increases for each decoupling rate group in any given year. Given the complexity in attempting to separately isolate each of these factors, particularly at a rate schedule level, only a collective impact of these factors is provided in this response.

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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.67

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.67:

Please provide an update of deferrals over the third evaluation year (July 2015 – June 2016) in the same format as provided in the appendix titled "Summary of Decoupling Deferrals" in the Second Year Evaluation report.

Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s. ("PSE") Response to H. Gil Peach & Associates Data Request No. 30.67, please find a Microsoft Excel file that contains a summary of decoupling deferrals by group for July 2015 through June 2016.

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Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.68

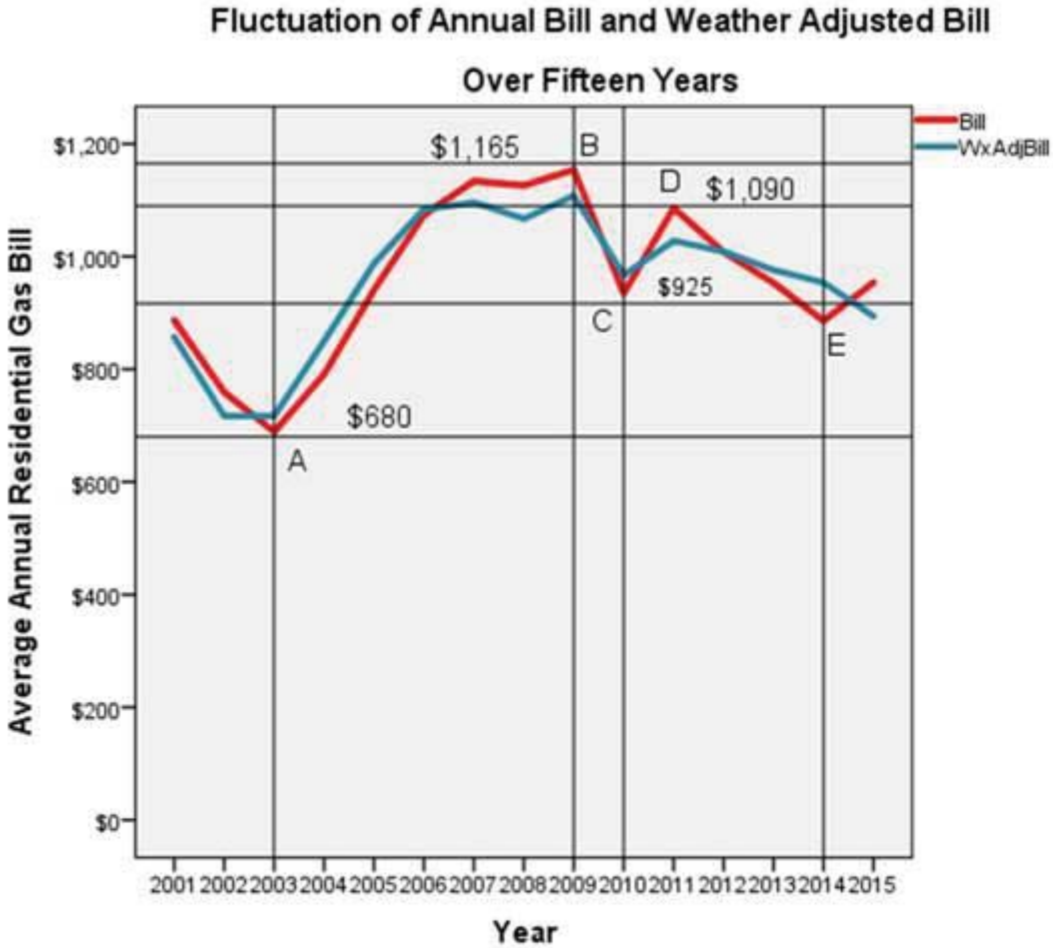
H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.68:

Please characterize points A, B, C, D and E in the graph of average residential natural gas bill over fifteen years. The lines on the graph show the actual average residential bill (red) and what would have been the weather-adjusted average natural gas bill (blue) over fifteen years of data supplied by PSE.

As can be seen in the graph, fluctuation due to weather (for example short cycles of warming and cooling is small – elsewhere, we calculate about 7%).

However, from Point A to Point B there is a 71% increase, from B to C there is a 31% decrease, from C to D there is about an 18% increase and from D to E there is about a 15% decrease in the average residential gas bill.

Please characterize points A, B, C, D and E in the graph of average residential natural gas bill over fifteen years and explain the major factor or factors that are influencing these sizable fluctuations.



Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s. ("PSE") Response to H. Gil Peach & Associates Data Request No. 30.68, please find a Microsoft Excel file that contains a graph summarizing the gas residential per unit rate from April 2000 to May 2016 with the total rate decomposed to show the delivery & trackers portion of the rate and the cost of gas portion of the rate. The shape of the gas residential per unit rate graph has the same shape as the graph above and shows the primary factor for the fluctuations seen between reference points A, B, C, D & E in the graph above is due to swings in the cost of gas over this time period.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-121697 and UG-121705
Puget Sound Energy, Inc. and NW Energy Coalition
Joint Petition for Approval of a Decoupling Mechanism

H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.69

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.69:

The earlier Data Request, DR 30.63 provides a monthly breakdown of total grant amounts and number of grants for program years 2010 to 2016 for each bill-assistance program including LIHEAP, PSE, Warm Home Fund, and Other. Please provide the same data provided in response to DR 30.63, but broken out by (a) residential natural gas bill-assisted customers and (b) residential electricity bill-assisted customers. Data should cover the three evaluation years. Our goal is to determine the average bill assistance grant separately by type of energy for natural gas and electric bill-assisted customers.

Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 30.69, please find a Microsoft Excel spreadsheet containing a monthly breakdown of total grant amounts, the number of grants and average amount per grant for PSE's HELP program by fuel type and combined. PSE does not have this information by fuel type for its other bill assistance programs.

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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.69

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.69:

The earlier Data Request, DR 30.63 provides a monthly breakdown of total grant amounts and number of grants for program years 2010 to 2016 for each bill-assistance program including LIHEAP, PSE, Warm Home Fund, and Other. Please provide the same data provided in response to DR 30.63, but broken out by (a) residential natural gas bill-assisted customers and (b) residential electricity bill-assisted customers. Data should cover the three evaluation years. Our goal is to determine the average bill assistance grant separately by type of energy for natural gas and electric bill-assisted customers.

Response:

Subsequent to Puget Sound Energy, Inc.'s ("PSE") Response to H. Gil Peach & Associates Data Request No. 30.69, PSE was requested to add three months of data to the original response to cover the most recently concluded low-income bill assistance program year.

Attached as Attachment A to PSE Supplemental Response to H. Gil Peach & Associates Data Request No. 30.69, please find a Microsoft Excel spreadsheet containing a monthly breakdown of total grant amounts, the number of grants and average amount per grant for PSE's HELP program by fuel type and combined from July 1, 2013 through September 30, 2016.

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Puget Sound Energy, Inc. and NW Energy Coalition
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H. GIL PEACH & ASSOCIATES (3rd PARTY REVIEW) DATA REQUEST NO. 30.70

H. GIL PEACH & ASSOCIATES DATA REQUEST NO. 30.70:

Please provide an analysis illustrating how individual rate schedules within the non-residential electric and natural decoupling rate groups contributed to decoupling deferrals over the three year evaluation period exclusive of the effects of the associated rate plan. Please then compare this to each schedule's contribution to the amortization of those overall deferrals for the group.

Response:

Attached as Attachment A to Puget Sound Energy's ("PSE") Response to H. Gil Peach & Associates Data Request No. 70, please find a Microsoft Excel spreadsheet illustrating how each individual rate schedule within the non-residential electric decoupling rate group contributed to decoupling deferrals over the three year evaluation period exclusive of the effects of the associated rate plan. Each schedule's contribution to the estimated deferrals for the group are then compared to the estimated contribution to the amortization of the group's estimated deferral. Attachment B to PSE's Response to H. Gil Peach & Associates Data Request No. 70 contains a similar analysis for PSE's non-residential gas decoupling rate group.

Each analysis begins with a comparison of the baseline allowed and volumetric (delivery) revenue at the levels experienced during the test year ending June 2012 that was used to calculate the baseline allowed revenue per customer before application of the rate plan increases. As can be seen from Attachments A and B, while there is a wide range of deferrals calculated by rate schedule, primarily due to the large range of customers sizes between the schedules contained within the rate groups, the overall estimated deferral is effectively zero. This is as expected, as the allowed revenue per customer and delivery revenue per unit were calculated using the same overall allowed revenue for the group. Next the same allowed revenue per customer and delivery revenue per unit were applied to the actual customer counts and energy usage to develop different deferrals. The deferrals for each schedule using actual customers and usage were then compared to the baseline levels. The difference represents a reasonable approximation of each schedule's contribution to the deferrals, before application of the rate plan, over the three year evaluation period and ignoring the other complexities associated with PSE's decoupling mechanisms, like its rate test and earnings test.

Each rate schedules contribution to amortization of the rate group's overall deferrals were then calculated by dividing the estimated deferral for each rate group in each year by the total by rate group usage in that year. The effective amortization rate was then multiplied by each rate schedule's usage to derive its contribution to the overall amortization of the deferral.

Finally, each rate schedule's contribution to the estimated difference in deferrals between the baseline and actual levels were compared to the estimated contribution to the amortization of those change in deferrals to determine the extent to which each schedule is covering its contribution to the group's estimated deferrals, absent the effects of the rate plan.

Attachment A shows that Schedules 40 and 43 are generally being subsidized by Schedules 24, 25, 29, 35, 46 and 49. Attachment B shows that Schedule 41 and 86 are generally being subsidized by Schedules 31, 31T, 41T and 86T.

It should be noted that, while the rate plan and other complexities of PSE's actual decoupling mechanisms were omitted from this analysis, the results should be reasonably indicative of the end result, at least insofar as the issue of potential cross-subsidies is concerned. The K-factor would likely only impact the scale of the results, and then only slightly given the small annual percentage increases. Similarly, since the rate test didn't trigger for these groups and the earnings test only had a modest impact, these would not be expected to change these results much. Finally, there may also be some minor differences due to the actual timing between when the deferrals were accumulated and when they were amortized. Again, this is largely a timing difference, rather than a factor that would materially change the relative contributions made by each schedule to amortizing the deferrals. Since relative usage doesn't change significantly over this short period of time, it is unlikely that any small changes that do occur would have little effect on the general conclusions drawn above.

Pacific Northwest: Forest, Ocean, Sky

Peach, H. Gil, Mark Thompson & John Joseph, Puget Sound Energy Electric and Natural Gas Evaluation: Three Years of Decoupling, an Independent Third-Party Evaluation of Puget Sound Energy's Electric and Natural Gas Decoupling Mechanism. Beaverton, Oregon: H. Gil Peach & Associates LLC, Monograph 2016-12, December 31, 2016.