Exh. JL-1CT
Dockets UE-170033/UG-170034
Witness: Jing Liu
REDACTED VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

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

TESTIMONY OF

Jing Liu

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Temperature Normalization
Decoupling Mechanism
Low Income Bill Assistance Program

June 30, 2017

Revised July 11, 2017 (redline)

CONFIDENTIAL PER PROTECTIVE ORDER – REDACTED VERSION

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jing Liu. My office address is 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington, 98504. My email address is jliu@utc.wa.gov.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission (Commission) as a Regulatory Analyst.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since July 2008.

Q. Would you please state your educational and professional background?

A. I hold a Bachelor's degree in English Language and Literature, a Master's of Arts degree in organizational communication and a Master of Science degree in communication technology and policy from Ohio University. I also completed four years of doctoral study in public policy at Ohio State University. I worked as a graduate research associate at the National Regulatory Research Institute (NRRI) from 2005 to 2007. I worked in the telecommunications section of the Commission from 2008 to 2014 and was responsible for developing and implementing telecommunications universal service policies; designating Eligible

Telecommunications Carriers in Washington and annually recertifying telecommunications carriers to receive high cost support. I also worked extensively on telecommunications low income assistance issues. Since I began working in the energy regulatory section of the Commission in 2014, I have reviewed tariff revisions of purchased gas adjustments, gas pipeline cost recovery mechanisms, decoupling, residential exchange credits, renewable energy credits, and property tax riders, as well as energy conservation plans.

Q. Have you previously testified before the Commission?

A. Yes. I provided testimony to the Commission in the proceedings addressing United Telephone Company of the Northwest Inc.'s intrastate access charges (UT-081393), the acquisition of Verizon Northwest, Inc. by Frontier Communications Corporation (UT-090842), the acquisition of Qwest Corporation by CenturyLink, Inc. (UT-100820), Frontier Communications Northwest, Inc.'s petition for competitive classification (UT-121994) and Avista Corporation's General Rate Case (UE-160228/UG-160229).

Q. What topics will you be discussing in your testimony?

A. My testimony has three components:

1. Temperature normalization
2. Decoupling mechanism
3. Low income bill assistance program

Q. What are your recommendations on temperature normalization adjustments?

A. On electric sales, I recommend the Commission adopt Staff's temperature normalization adjustment using schedule-level analysis, instead of the Company's system-level adjustment, and not apply any sales adjustment to Schedule 29. For natural gas sales, I recommend the Commission adopt the Company's rate class-level adjustment instead of its system-level adjustment.

Q. What are your recommendations on the decoupling mechanism going forward?

A. I recommend the Commission continue the decoupling mechanism for delivery cost recovery for another four years, and start implementing a separate decoupling mechanism for fixed production cost recovery. While I believe the Commission should adopt some of the Company's decoupling proposals, I also believe some of PSE's proposals should be rejected and that others should be modified as I explain later in my testimony.

Q. What are your recommendations on the Company's low income bill assistance program?

A. I recommend the Commission accept the Company's proposals on this subject. I also recommend the Commission clarify the base funding level in the final order, and direct stakeholders to form an advisory group to work collaboratively on low income bill assistance issues between general rate cases.

II. TEMPERATURE NORMALIZATION

A. Overview

Q. Please summarize the key findings of your testimony on electric temperature normalization.

A. I contest the Company's sales adjustments for both electric and natural gas temperature normalization developed by the Company's witness, Dr. Chang. For electric temperature normalization, Staff recommends: (1) using the results from a schedule-level analysis instead of a system-level analysis, and (2) excluding Schedule 29 from the sales adjustment. PSE proposed a $17,527,345 net operating income (NOI) adjustment to its test year electric NOI (Barnard Electric Adjustment 6.02). My analysis produces a normalizing adjustment of $20,557,384 to the Company's test year electric NOI (Staff Electric Adjustment 13.02), representing an increase of $3,030,039 relative to the Company's proposal.

Staff's adjustment also changes the Company's variable production factor which, in turn, affects the calculation of the Company's net power cost. Because Staff proposes an additional upward sales adjustment under normal weather conditions, power cost will increase, reflecting the corresponding increase in expense associated with the additional sales. Staff's adjustment also impacts the rate spread and rate design consideration because the test year temperature-normalized sales volumes at the schedule-level are slightly different from the Company's proposal.

A summary of the differences in application of Staff's and the Company's models is provided below in Table 1 for comparison.

Table 1. Staff and PSE Electric Temperature Normalization Adjustment

	PSE System Model	PSE Schedule Model	Staff Schedule Model
Sales Adjustment			
kWh Adjustment	281,706,865	360,790,144	326,355,802
Adjustment as a Percentage of Actual Sales for Weather Sensitive Schedules	1.43%	1.83%	1.66%
Revenue Adjustment			
Sales Adjustment	$ 28,313,253		$ 33,207,905
Revenue Sensitive Items	$ (1,348,107)		$ (1,581,161)
Federal Income Tax	$ (9,437,801)		$ (11,069,360)
Net Impact on Net Operating Income	$ 17,527,345		$ 20,557,384~~0,557,384~~

Q. Please summarize the key findings of your testimony on PSE's natural gas temperature normalization adjustment.

A. As with electric, Staff recommends using the results from a rate class-level analysis for gas temperature normalization instead of a system-level analysis. PSE proposed a $16,069,959 test year NOI adjustment (Barnard Gas Adjustment 6.02) using system-level analysis. Staff proposes an adjustment of $16,435,328 to the Company's NOI (Staff Gas Adjustment 11.02) using a rate class-level analysis, which represents an increase of $388,883 relative to the Company's proposal. Staff's adjustment incorporates purchased gas costs. Table 2 provides the comparison.

Table 2. Staff and PSE Natural Gas Temperature Normalization Adjustment

	PSE System Model		Staff Schedule Model	
Therms Adjustment		83,004,479		84,847,572
Adjustment as a Percentage of Actual Sales for Weather Sensitive Schedules		9.19%		9.40%
Revenue Adjustment	**$**	**58,038,526**	**$**	**59,630,060**
Purchased Gas Costs	$	(30,713,140)	$	(31,634,036)
Revenue Sensitive Items	$	(2,638,547)	$	(2,710,902)
Federal Income Tax	$	(8,640,394)	$	(8,849,793)
Net Impact on NOI	**$**	**16,046,445**	**$**	**16,435,328**

Q. Could you please describe the purpose of temperature normalization?

A. Temperature normalization, also called weather normalization or revenue normalization due to temperature, is a restating adjustment to a company's test year revenue to reflect a level of sales under normal weather. It estimates the energy that a utility would have sold if the weather had been "normal."

Given that energy consumption is highly correlated with temperature, the Company's sales are subject to temperature swings that are out of the Company's control. Temperature normalization allows us to evaluate revenue sufficiency under normal weather and, prospectively, under the expectation that weather will be normal in the rate year. As a result, temperature normalization protects both a company and its customers from misleading revenue signals resulting from abnormal weather. Temperature normalization also enables us to compare a company's earnings from year to year, with temperature influence taken out of the equation.

For example, if a test year has a warmer winter than normal, a company's electric or gas sales would be lower than the normal level due to a relatively low heating load. In this example, a company's per-book revenue should be adjusted upward to a sales volume expected under a normal winter, as setting prospective rates relies on the assumption that temperature will be normal during the rate year. Without this adjustment, test year revenue would be lower than normal, perhaps even giving the impression that the company needs a rate increase when, from a weather-normalized perspective, revenues would be sufficient.

The opposite would also be true if a test year has a colder winter than normal; a company's per-book revenue should be adjusted downward to a level achievable under a normal winter. Without this adjustment, the company's test year sales volumes and resulting revenue would be very high relative to what the company would expect under normal weather. High weather-related sales volumes could mask the need for rate relief that would be apparent from a normal weather perspective.

For electricity sales, a hotter than normal summer could lead to higher sales in the test year. The per-book revenue should be adjusted downward to a sales level under a normal summer. Likewise, the opposite would apply to a cooler than normal summer.

Q. What pieces of information are required to perform a temperature normalization adjustment?

A. Typically, temperature normalization involves three basic components: (1) calculation of deviation in test year heating degree days (HDD) or cooling degree days (CDD) from a "normal" benchmark;[1] (2) calculation of weather sensitivity coefficients from statistical models; and (3) identification of the number of customers for each weather sensitive schedule in the test year. The product of these three components produces an adjustment in energy sales.

Q. What is "normal" temperature for this purpose?

A. PSE uses the temperature data published by the National Oceanic and Atmospheric Administration (NOAA) for SeaTac International Airport. The Company aggregates hourly temperature readings into daily and monthly HDDs and CDDs and uses the rolling 30-year average HDDs and CDDs as the benchmark for normal weather conditions. With the exception of November 2015, all winter and shoulder months in the test year were warmer than the 30-year normal. With the exception of September 2015, all summer months in the test year were hotter than the 30-year normal.

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[1] HDD measures the deviation in the actual temperature below the baseline temperature, commonly 60 or 65 degrees Fahrenheit. Higher HDDs indicate colder weather. CDD measures the deviation in the actual temperature above the baseline temperature, also commonly 60 or 65 degrees Fahrenheit. Higher CDDs indicate hotter weather. Using 65 as the baseline temperature, if the temperature is 51 degrees Fahrenheit, HDD is 14 and CDD is 0; if the temperature is 71 degrees Fahrenheit, HDD is 0 and CDD is 6.

Q. Could you explain how to calculate temperature sensitivity coefficients?

A. Because energy consumption is typically highly correlated with temperature, HDD and CDD serve to explain variation in energy sales for most customer groups.[2] A regression model is capable of producing weather sensitivity coefficients that quantify the amount of change in kilowatt-hour (kWh) or therm sales per degree change in temperature. This coefficient multiplied by the total change in HDD or CDD and the number of customers determines the adjustment needed to achieve normal sales.

B. Staff Analysis of Electric Temperature Normalization Models

Q. What problems do you see in the Company's electric temperature normalization adjustment?

A. I see two issues. First, the method of allocating system-level model results using separate schedule-level models – in effect, requiring reconciliation of the results of two different sets of models – is problematic. Second, PSE relies on a model with a poor fit for Schedule 29 irrigation customers; the model fails to show a strong correlation between usage and temperature and is therefore of very limited use for normalization.

[2] More specifically, energy consumption is highly correlated with temperature once the temperature exceeds a threshold that challenges human comfort. For example, as ambient temperature cools to below 65 degrees Fahrenheit, further decrease in temperature are highly correlated with increased heating load.

1. The Two-Model Approach Is Problematic

Q. How does the Company implement its two-model approach?

A. The Company's approach is unnecessarily complicated, requiring two models and three steps.

To arrive at its overall normalizing adjustment, the Company uses the sales adjustment produced by its system-level analysis. So, in the first step, Dr. Chang develops a system model, in which he uses daily Generated, Purchased and Interchanged[3] (GPI) system load data from January 1, 2012 to December 31, 2015, and the corresponding daily HDDs and CDDs. He uses ARMA conditional Least Squares models to estimate temperature sensitivity coefficients for the entire system.[4] Temperature sensitivity coefficients are calculated for each month to recognize the varying usage sensitivity in different temperature ranges.[5] In addition to 65 degrees Fahrenheit baseline temperature for HDD (HDD65), Dr. Chang also uses 45 degrees Fahrenheit as a secondary baseline temperature (HDD45) in the model to account for more severe usage sensitivity under profoundly cold weather. The model also contains monthly base load intercepts, variables for holidays, weekends, and a few special days that are associated with severe outages and meter-reading errors. The monthly HDD/CDD coefficients are then applied to the deviation of actual temperature from the normal benchmarks as well as the average

[3] GPI is the total power necessary to meet the load demanded by PSE customers. As the term implies, the power was either generated by PSE power plants, purchased from third parties, or in an exchange with other utilities.
[4] ARMA model stands for Autoregressive Moving Average Model. It is a modification of ordinary least squared model with autoregressive terms.
[5] This is accomplished by using the interaction terms between monthly dummy variables and HDD/CDD.

number of customers in each month in the test year to calculate the adjustment to the electricity system's load and reflect normal weather conditions. The final result is then scaled back by applying a line loss factor to reflect the actual kWh sales to customers.

The Company then allocates this overall system-level sales adjustment to each schedule using the results of a second, schedule-level analysis. In his second step, Dr. Chang develops temperature models for each of the 15 schedules that are deemed temperature sensitive. Either population daily data or sample daily data is used for each schedule. The schedule-level models are simplified in that the temperature coefficients do not vary by month.

But because the two models produce different estimates for the total sales adjustment, in his third step, Dr. Chang must reconcile the difference in sales adjustment from the system-level model and schedule-level model. He does this by allocating the difference to each schedule based on its relative proportion of sales adjustment for the month. The respective tail block rates are then applied to the sales adjustments.

Q. Why do you think the Company's two-model approach is problematic?

A. Staff believes PSE's two-model approach attempts to reconcile two separate models that are irreconcilable. The "extra" or "deficient" adjustment produced by the system-level model cannot simply be spread over rate schedules using the schedule-level models. Instead, the schedule-level models produce the *exact* sales adjustment that *belongs* to each weather-sensitive schedule, no more, no less. Any allocation to a schedule beyond what is identified by the schedule-level results is unfair to the customers in the schedule.

The purpose of the temperature models is to develop accurate temperature sensitivity coefficients specific to each customer class in order to calculate each class's usage under normal weather conditions. Staff does not believe the two-model approach, which applies the system model result for the schedule-level adjustment, is appropriate for the following reasons: (1) the average system load per customer is not a good measure for usage patterns; (2) the allocation to the various schedules is arbitrary; and (3) the schedule-level models are not properly specified.

Q. Why is the average system load per customer not a good measure for usage patterns?

A. PSE's system model uses System GPI load per customer as the dependent variable. System load per customer is not as meaningful a measure as the usage per customer at the schedule level because the system data reflect aggregated usage from heterogeneous groups and the growth/decline in customer base varies by group over the course of four years. Furthermore, the daily system GPI includes loads for non-temperature sensitive customers, which can skew the system load data.[6] The Company also assumes a constant line loss of 7.3 percent in the system load, but in reality, line loss may not be constant over time. Therefore, while the system model might be useful for near-term system level forecasting purposes and can serve as a

[6] The schedules that are considered not temperature sensitive are Schedule 35, Schedule 46, Schedule 49 and Schedule 50 – 59. Based on JAP-03, sales from these schedules constitutes about 3.4 percent of the total delivered load in the test year. The Company does not have daily readings for customers on these schedules and cannot exclude these usages from GPI daily data.

good basic check for the results from the schedule-level models, it is not suited to the temperature normalization adjustment where the goal should be to develop accurate temperature sensitivity coefficients specific to each customer class.

Q. Why do you believe the Company's allocation to schedules is arbitrary?

A. There is no precise way to allocate the system-level sales adjustment to schedules. As I stated earlier, in an attempt to allocate the system-level sales adjustments to each schedule, Dr. Chang relied on simplified schedule-level models to arrive at monthly allocation factors for each heat-sensitive schedule. The Company's schedule-level models produced 79 million kWh more in the sales adjustment (28 percent) than the system model result. Dr. Chang used the monthly allocation factors to reconcile the differences between the system model and the schedule-level models. Although this practice is based on a sincere attempt to allocate the system load adjustment to each schedule in a somewhat equitable manner, the result may significantly deviate from the true usage sensitivity at the schedule level. There is no theoretical basis on which to allocate the difference between system-level adjustment and schedule-level adjustment.

Put another way, the Company's system-level model produces an adjustment that cannot be explained by the schedule-level models. The results of the schedule-level models are inconsistent with the system-level model results, and the Company, therefore, has to arbitrarily allocate the "extra" or "deficient" adjustment from the system-level model across the schedule-level models. Arbitrarily assigning this "extra" or "deficient" adjustment is unfair to classes of customers that, via the schedule specific model, are shown not to have the usage sensitivity the adjustment would imply. This complication is more pronounced in gas temperature models. The system-level model indicates that gas usage in July is sensitive to temperature, but the schedule-level analysis indicates that no schedule is heat sensitive in July.[7] However, the Company arbitrarily allocated the entire July sales adjustment to the residential customer group.[8]

Q. Why do you believe the Company's schedule-level models are not properly specified?

A. Related to the allocation method just described, the schedule-level models are not correctly specified. As a result, the allocation of the sales adjustment among schedules is not precise. The Company's electric schedule-level models use single HDD/CDD variables for all months of the year, rather than monthly HDD/CDD variables as used in the Company's gas rate class-level models. In other words, the models do not distinguish the monthly variation of heat sensitivity. Rather, they assume that customer heat sensitivity in the winter months, shoulder months, and summer months does not change. In reality, heat sensitivity in colder months is much stronger than heat sensitivity in mild months. Therefore, the Company's models do not adequately control for changes in monthly temperature sensitivity. In my opinion, the simplified models at the schedule level do not provide a reasonable basis for allocation and could produce misleading results. Even if we were to accept

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[7] P value is 0.0317, below the conventional threshold of 0.05 for 95 percent confidence level.

[8] The Company kept the July HDD coefficient in the residential schedule model even though the p value is 0.1027, above the conventional threshold of 0.05. As a result, the gas sales adjustment for July from the system model is allocated to the residential schedule in PSE's weather adjustment.

the Company's two-model approach, the sales adjustment from the system model is not properly allocated to each schedule under PSE's analysis.

Q. How do you recommend the Commission correct the problem you identified?

A. Since the goal is to identify the temperature sensitivity specific to each schedule or rate group, the Commission should focus on getting the schedule-level models right. As I have described above, there are several reasons why the system-level models should not be used to make schedule-level adjustments. Rather, schedule-level adjustments should be made by using schedule-level models. Further, Staff recommends improving the schedule-level models by adding additional model specifications that differentiate temperature sensitivity by month.[9]

Q. Are you concerned about the use of sample data for schedule-level models?

A. No. The electric sales weather normalization is applied to fourteen rate schedules (including sub-schedules). Nine rate schedule models use daily energy sales histories collected for the entire rate schedule population. They are Schedules 05, 10, 11, 12, 29, 31, 40-25, 40-26 and 40-31. Five rate schedules used sampled customer usage data. They are Schedules 07, 08, 24, 25 and 26. It is possible that the sample data is subject to sampling error. Based on Dr. Chang's detailed

[9] In Staff's schedule-level models, I use interaction terms between monthly dummy variables and HDD/CDD variables. Similar to Dr. Chang's system model, I kept dummy variables for 12 months as monthly intercepts; I kept the dummy variables for Saturday, Sunday, holidays, semi-holidays and special days indicated in Dr. Chang's system model; autoregressive term and monthly trend variables are also included when statistically significant. Also similar to Dr. Chang's approach, I tested baseline temperature of 65 Fahrenheit and 45 Fahrenheit for all schedules and retained all statistically significant monthly HDD65/HDD45 variables in the final models.

explanation,[10] however, Staff is satisfied with the rigor of his sampling process. Staff believes sampled data, in theory, should be representative of the target population for those schedules. Even if repeated sampling could produce slightly different outcomes, the difference should not be material. Usage per customer data specific to each schedule from a carefully crafted sample is superior to average GPI load per customer at the system level.

2. Electric Schedule 29 should be removed from the temperature-related sales adjustment

Q. What problem does Staff see in the weather normalization adjustment for Schedule 29?

A. The Company reduced the test year sales to Schedule 29 customers by 158,747 kWh, assuming normal weather. Staff believes the adjustment should not be made because the Schedule 29 model has a very poor fit and high error.

Q. Does the temperature normalization model for Schedule 29 work well?

A. No. Schedule 29 is for seasonal irrigation and drainage pumping service. The customers on this schedule use electricity primarily for agricultural irrigation and water pumping. Dr. Chang and I both examined the correlation between these

[10] PSE Response to UTC Staff Data Request No. 380. For each of the five rate schedules, Dr. Chang determined the sample size to meet an error margin of five percent or less based on each schedule's population size, mean, and standard deviation. He made sure that each sampled customer has a complete daily usage history for four years. A random number generation tool in Excel is used to draw the customer samples. Sampled data were verified and edited to make sure there were not many missing or erroneous observations.

customers' usage and cooling degree days in the summer. Adjusted R-squared is an accepted, common statistic that is used to evaluate how well a model fits its data. A high Adjusted R-squared would indicate a strong correlation between usage and temperature. If a schedule shows an R-squared of 0.90, for example, it would indicate that temperature variation explains 90 percent of the usage variation. My Schedule 29 model has an adjusted R-squared of 0.38. Dr. Chang's model has an adjusted R-squared of 0.36. This indicates that our models do not support a strong correlation between Schedule 29's usage and temperature. Temperature explains less than 40 percent of the usage variation. In other words, non-temperature causes represent the majority of the variation in usage. In comparison, models for other rate schedules all have an adjusted R-squared well above 0.60, and often times above 0.90.

Q. Did any other statistical measure inform your opinion that the weather model for Schedule 29 is not useful?

A. Yes. Another good reference statistic is mean absolute error percent (MAPE). It represents the average deviation of each observation's predicted value from the actual value. A smaller MAPE indicates greater forecasting accuracy. The MAPE from my model is 87 percent. This means that on average, the usage forecast using my model deviates from the actual usage by 87 percent. The MAPE from Dr. Chang's model is 89 percent. Again, in comparison, most of the models for the other rate schedules have a MAPE of less than 10 percent. Reliance on a model with a poor fit and high error produces unreliable and inaccurate estimates of usage under normal weather and should be rejected.

Q. What is your recommendation regarding the Company's proposed Schedule 29 adjustment?

A. I recommend that no temperature normalization adjustment be applied to Schedule 29 for the reasons outlined above.

Q. Please summarize your recommendations for PSE's electric temperature normalization adjustments?

A. I recommend the Commission adopt my sales adjustment to normalize the effect of temperature in the test year, using schedule-level models and excluding Schedule 29 from temperature normalization. Staff's sales adjustment lands in the middle of the Company's system-level and schedule-level results. Based on Staff's models, PSE could have sold 326 million kWh more electricity under normal weather. The net impact on the Company's test year NOI is $20,557,384. The statistical output of my models, including all temperature coefficients, is set forth in Exh. JL-2. The revenue adjustment calculation is set forth in Exh. JL-3.

C. Staff Analysis of Natural Gas Temperature Normalization Models

Q. Do you see problems with the Company's natural gas temperature normalization adjustment?

A. Yes. I see the very same problem I identified in the Company's electric temperature sales adjustment, namely the use of a two-model approach. Earlier, I discussed three reasons why the results from a system-level model are not appropriate for schedule-level adjustments: (1) the average system usage per customer is not a good measure for usage patterns; (2) allocation to the various schedules is arbitrary; and (3) schedule-level models are not properly specified. The first two reasons also apply to the Company's gas temperature adjustment. The third reason does not apply because the Company's gas rate class-level models are properly specified.

Q. Please briefly describe PSE's temperature normalization methodology for natural gas service.

A. For natural gas temperature normalization, the Company employs three system-level models to develop adjustments for firm, interruptible, and transportation sales. The Company also examines usage sensitivity at the rate class level for each weather-sensitive schedule (commercial and industrial, firm and transportation). PSE's natural gas analysis differs from its electric analysis in two ways: (1) the Company uses monthly billing data for the most recent five years for rate class-level analysis because daily gas data is not available at rate class level; and (2) the Company's natural gas rate class models are specified with monthly HDD/CDD variables. The temperature coefficients differentiate heat sensitivity by month.

Q. What is your recommended treatment of PSE's natural gas temperature normalization adjustments?

A. For the reasons I discussed regarding the electric adjustment, I likewise, in the gas context, do not recommend using system model results for rate class-level sales adjustments. I recommend the Commission adopt the temperature sensitivity coefficients from the Company's rate class models because they generate weather sensitivity coefficients specific to each rate class. My modification to Mr. Piliaris' revenue impact calculation from gas temperature normalization is presented in addition to my testimony as Exh. JL-4. My recommendation results in an upward adjustment of 85 million therms to the Company's natural gas sales in the test year, which is 1.8 million therms (2.2 percent) larger than the Company's sales adjustment. After deducting gas cost, fees and taxes, the impact on the Company's NOI is $16,435,328.

Q. Do you have concerns about using only five years of monthly data in the natural gas weather normalization modeling?

A. Yes. As a general matter, a longer time period is preferable as a larger number of data points would better capture the relationship between temperature and usage. However, in this case the use of five years of monthly data is appropriate. Although a longer time period provides for a larger sample size, the downside of using a longer time period is that data spread over numerous years may not give a clear indication of the most current usage sensitivity because factors such as the health of the economy, conservation achievements, building codes, and other advances in technology may influence the usage patterns specific to a rate class over time.

To test whether temperature sensitivity over the last ten years has changed (and, accordingly, whether using a data set that spans ten years is advisable), I produced rate class-level gas models using ten years of data. The output of this model is presented in Exh. JL-5. After careful examination of the model output, I do not recommend using a ten year dataset.

The ten year data provides a larger sample size, but with this data it does not yield more accurate temperature sensitivity results. I conducted tests to determine whether the coefficients from the first five years of the data set are statistically different from those of the second five years.[11] This analysis indicated that the weather sensitivity of three rate classes changed significantly from the first to the second time period (*see* Chow's test results in Exh. JL-5).[12] When usage patterns change over time it is preferable to use data from a more recent time period because it will better reflect the relationship between temperature and current usage. In addition, in all of my rate class models using ten year data, the Adjusted R-squared and MAPE are inferior to those for the models using five year data, especially for larger commercial and industrial customer classes (*see* comparison in Exh. JL-6).[13]

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[11] A Chow's test is used to compare coefficients in split periods. A Chow's test is a statistical test used to determine whether the coefficients in two linear regressions, developed from split data sets, are statistically different. The test is useful for determining whether the populations in split data sets share the same characteristics.

[12] The schedules that failed Chow's test are Schedule 41 Commercial, Schedule 41 Commercial Transportation, and Schedule 87 Commercial Interruptible Transportation.

[13] There are many reasons that could be affecting the models using the ten year data. Customer composition for larger users could have shifted over time. The data's consistency could also have been affected by a change to the Company's billing system within this time period. Over time, customer migration could also make it difficult to sort out the data. For some transportation rate classes, data is not even available for the full ten years.

Therefore, I recommend the Commission use results from the five year dataset in this case, as developed by Dr. Chang and presented in my Exh. JL-4. His rate class-level analysis resulted in an upward sales adjustment of 84,847,572 therms; reasonably close to his system-level adjustment of 83,004,479 therms.

Q. What accounts for the close results between the Company's system-level analysis and its rate class-level analysis for gas temperature adjustment?

A. Most likely, the "purity" of the system data used. Virtually all rate classes with firm gas demand demonstrate weather sensitivity. It is not surprising that the firm gas system-level model and the rate class-level models yielded results within 2 percent of each other. In comparison, the data for gas interruptible total sales, gas transportation total sales and electric system load contain a higher proportion of non-temperature sensitive usage. Therefore, the two approaches for temperature adjustment yielded a wider difference for gas interruptible, gas transportation and electric system total sales. This illustrates one limitation of the system-level analysis in which the daily system data does not exclude non-weather sensitive load. The more noise in the system usage data, the less reliable the results.

Q. Does Staff have any other recommendations regarding the Company's gas weather normalization methodology going forward?

A. Yes, dealing with monthly billing data for rate class-level analysis requires a delicate balance between sample size and relevance of the data. A sample size larger than five years is better if we can ensure data consistency. I recommend that the

Company scrutinize the historical billing data by identifying very large customers' migration across schedules and other critical events.[14] With good and clean data, temperature normalization models can use data from a time period longer than five years.

III. DECOUPLING MECHANISM

A. Overview

Q. Could you provide a quick overview of PSE's current decoupling mechanism?

A. Yes. PSE's current decoupling mechanism was approved by the Commission in 2013.[15] In the 2013 Decoupling Order, the Commission also approved a multi-year rate plan to allow modest annual increases in PSE's rates to break the cycle of continuous rate cases.[16] As a result, PSE's decoupling rates calculation involves: (1) deferral - the difference between the Allowed Revenue and the Actual Revenue collected for decoupled schedules, and (2) a "K-factor" or rate plan that allows a three percent increase in revenue per customer for electric service and a 2.2 percent increase in revenue per customer for gas service.[17] PSE's current decoupling mechanism applies only to the Company's delivery revenue.

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[14] Such critical events can include change in billing practice, acquisition or removal of service territory, etc.
[15] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-121697, UG-121705, UE-130137, and UG-130138, Order 07 (Jun. 25, 2013) ("2013 Decoupling Order").
[16] 2013 Decoupling Order, 74-75, ¶¶ 171-173.
[17] PSE witness Mr. Piliaris provided a description of the decoupling deferral in his direct testimony. *See* Exh. JAP-1T at 107:5-18.

Q. What is decoupling and what is its purpose?

A. Decoupling is a regulatory mechanism under which a utility's authorized revenue is decoupled from its sale volumes. Under a decoupling mechanism, a utility is allowed to recover a fixed amount of revenue regardless of its volumetric energy sales. This is to financially protect the utility from reductions in short-term earnings that are a direct result of the utility's programs to increase the efficiency of energy use.[18] In its policy statement on decoupling, the Commission stated that such financial protection of utilities is consistent with the Commission's ongoing statutory obligation to set rates for investor-owned utilities that are just, fair, reasonable and sufficient.[19]

Decoupling has two goals that work hand-in-hand: (1) to encourage PSE to sponsor and promote conservation more aggressively; and, (2) to reduce the Company's revenue volatility and provide an opportunity for the Company to recover its fixed costs.

Q. How does decoupling promote energy conservation?

A. Because the Company is authorized to recover its costs and earn a return on rate base based on a fixed revenue per customer under the current decoupling mechanism, the Company's earnings are no longer tied to energy sales. Therefore, the throughput incentive, i.e., the Company's incentive to maximize sales, is removed. Customers

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[18] *In the Matter of the Wash. Utils. & Transp. Comm'n's Investigation into Energy Conservation Incentives*, Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets, 4, ¶6 (Nov. 4, 2010) (Decoupling Policy Statement).
[19] *Id.*

benefit from increased conservation by reducing energy bills in the short term and reducing, or postponing, the need to pay for capital intensive investment in utility infrastructure in the long term. The Commission endorsed this rationale in its 2013 Decoupling Order, stating:

> The decoupling mechanisms we approve mean that PSE's recovery of the fixed costs it incurs for infrastructure and operations necessary to deliver power and natural gas will no longer depend on the amounts of electricity and natural gas the company sells. This removes the so-called throughput incentive, thus promoting PSE's more aggressive pursuit of cost-effective conservation to which it commits as part of the decoupling mechanisms. With the throughput incentive eliminated, the company will be indifferent to sales lost as a result of the success of its conservation efforts.[20]

Q. How does decoupling improve fixed cost recovery?

A. Decoupling is a way to address the fact that a large portion of the Company's costs of providing energy distribution service is fixed while revenue recovery still largely relies on volumetric energy sales. To the extent that volumetric sales are higher or lower than expected, the Company either over- or under-recovers its fixed costs. A full decoupling mechanism, in establishing a revenue target and providing for a mechanism for annually truing-up actual revenue with allowed revenue, insulates the Company's earned revenue from the impacts of weather, conservation, and other factors that influence customer usage. The current decoupling mechanism sets the Company's annual revenue target based on authorized Revenue per Customer and the actual number of customers. Since the customer base is relatively stable, the Company's revenues are constant. The decoupling rates are imposed as a volumetric

[20] 2013 Decoupling Order, ii (italics removed from original).

surcharge, so customers who use more will still pay more than other customers, thereby preserving the traditional volumetric rate structure.

Q. Has the Company's decoupling mechanism accomplished its intended goals?

A. Yes, I believe the current decoupling mechanism is largely a success, and has met the two enumerated goals. Decoupling has led to higher conservation achievements and reduced revenue volatility. The current decoupling mechanism incorporates the Company's commitment to additional acquisition of energy efficiency resources. The Company has satisfactorily achieved the additional five percent savings in its electric conservation program, in accordance with its commitment at the commencement of the decoupling mechanism.[21]

In terms of improvement in revenue stability, the Company has earned more than the authorized rate of return of 7.77 percent in 2015 and 2016 for its electric operations; as well as in 2014, 2015, and 2016 for its natural gas operations.[22] Although a variety of reasons could have contributed to the improved earnings, Staff believes that the rate plan and the decoupling mechanism have provided a stable regulatory platform for the Company during the past three-and-a-half years.

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[21] *In the Matter of Puget Sound Energy's 2014-2015 Biennial Conservation Target Under RCW 19.285.040*, Docket UE-132043, Order 05, 1, ¶ 3 (Aug. 15, 2016).

[22] *See Puget Sound Energy, Inc. 2013 Electric Commission Basis Results of Operations*, Docket UE-140536 (Mar. 31, 2014); *Puget Sound Energy, Inc. 2013 Gas Commission Basis Results of Operations*, Docket UG-140537 (Mar. 31, 2014); *Puget Sound Energy, Inc. 2014 Electric Commission Basis Reports Showing Restated Results of Operations*, Docket UE-150528 (Mar. 31, 2015); *Puget Sound Energy, Inc. 2014 Gas Commission Basis Reports Showing Restated Results of Operations*, Docket UE-150529 (Mar. 31, 2015); *Puget Sound Energy, Inc. 2015 Electric Commission Basis Reports Showing Restated Results of Operations*, Docket UE-160375 (Mar. 31, 2016); *Puget Sound Energy, Inc. 2015 Gas Commission Basis Reports Showing Restated Results of Operations*, Docket UE-160376 (Mar. 31, 2016); *Puget Sound Energy, Inc. 2016 Electric Commission Basis Reports Showing Restated Results of Operations*, Docket UE-170221 (Mar. 31, 2017); *Puget Sound Energy, Inc. 2016 Gas Commission Basis Reports Showing Restated Results of Operations*, Docket UE-170222 (Mar. 31, 2017).

In addition, the third-party evaluation of PSE's decoupling mechanism reported that the decoupling mechanism has functioned as intended and has had little to no adverse impact on conservation achievement, service quality, or low income households.[23]

Q. Does Staff recommend continuation of the decoupling mechanism?

A. Yes. Staff recommends the Commission continue to apply the decoupling mechanism to the Company's delivery cost recovery. Staff further recommends the Commission authorize a separately tracked decoupling mechanism for the Company's fixed production cost recovery. However, while Staff believes that continuation of the decoupling mechanism would be consistent with the public interest, specific components of the mechanism should be improved in the manner in which I describe below.

Q. What are the Company's proposals regarding its Decoupling Mechanism?

A. The Company proposed the following changes to the decoupling mechanism. Some of the Company's proposals are based on policy arguments, others are more technical and logistical. PSE proposes to:

1. Re-group non-residential schedules;[24]
2. Incorporate fixed production costs in the future decoupling mechanism;[25]

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[23] Piliaris, Exh. JAP-29 at 59-115.
[24] Piliaris, Exh. JAP-1T at 129:14 – 133:20.
[25] *Id.* at 127:1 – 129:12.

3. For purposes of the earnings test, remove all normalization adjustments from Commission Basis Report (CBR) net operating income;[26]

4. Implement a dead band for earnings sharing;[27]

5. Make decoupling mechanism permanent;[28]

6. Change to a new method of calculating "current revenue" for the soft cap test;[29]

7. Increase the soft cap to five percent for the gas residential group and all electric rate groups;[30]

8. Change to a new method of allocating shared earnings to customer groups;[31]

9. Change to a new method of calculating "actual revenue" for non-residential gas customers;[32]

10. Adopt additional commitments associated with the decoupling mechanism.[33]

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[26] Doyle, Exh. DAD-1T at 14:1 – 21:6.
[27] *Id.* at 21:7 – 25:18.
[28] Piliaris, Exh. JAP-1T at 146:6 – 146:14.
[29] *Id.* at 134:1 – 135:2.
[30] *Id.* at 135:3 – 138:7.
[31] *Id.* at 138:8 – 139:5.
[32] *Id.* at 139:6 – 140:10.
[33] *Id.* at 144:15 – 146:5.

B. Staff's Analysis of PSE's Decoupling Proposals

Q. What are Staff's recommendations regarding the Company's various proposals?

A. Staff recommends the Commission adopt Staff's modifications to the Company's proposals 1 and 2; reject the Company's proposals 3, 4, and 5; and accept the Company's proposals 6 through 10. I provide a detailed analysis and recommendation for each proposal in the corresponding section below. Re-grouping of non-residential groups and the future decoupling mechanism for fixed production costs warrant more in-depth discussion, therefore, I discuss these proposals first.

1. PSE's Proposal to Regroup Non-Residential Schedules Falls Short

Q. Please describe the Company's proposal.

A. The Company proposes to further disaggregate the decoupling rate groups for non-residential customers. Currently, for the decoupling rate calculation, there are three electric non-residential groups and one gas non-residential group in addition to the residential groups. The electric non-residential groups are: (1) Schedules 12/26; (2) Schedules 10/31; and, (3) Schedules 8/24, 11/25, 29, 43, 40, 46 and 49. The gas non-residential group consists of Schedules 31/31T, 41/41T, and 86/86T.[34]

Based on his observations of customer usage patterns, PSE witness Mr. Piliaris proposed breaking the third electric non-residential decoupling group into

[34] "T" stands for transportation customers.

three smaller groups: Schedules 8/24 (small demand customers); Schedules 7A, 11/25, 29, 35, and 43 (a mix of medium demand customers); and Schedules 40, 46, and 49 (large general service and high voltage customers).

Mr. Piliaris also proposed breaking the natural gas non-residential group into two smaller groups: (1) Schedules 31/31T (small usage customers); and, (2) Schedules 41/41T, 86/86T (large usage customers).[35]

Q. Do you agree with these regrouping proposals?

A. No. Staff agrees that PSE's proposal to disaggregate non-residential groups would be a step in the right direction. The new groups do contain customers with relatively similar usage patterns. However, PSE's proposals do not go far enough to adequately address the problem of cross subsidization among non-residential customer groups and the challenge of equitable fixed cost recovery.

Q. What does Staff propose, instead?

A. For electric delivery decoupling, Staff recommends the Commission order PSE to create three separate groups for certain schedules, and discontinue decoupling for the others entirely. There should be three individual rate groups for the purpose of delivery decoupling: (1) Schedule 7 (Residential Single Family); (2) Schedules 8/24 (Small Demand); and, (3) Schedules 7A, 11/25 (Medium Demand). These schedules should have their own rate groups because they have similar usage patterns within

[35] Piliaris, Exh. JAP-1T at 120:8-22, 129:14 – 132:14.

the groups. Putting them in separate groups better aligns cost causation and responsibility.

Staff recommends the Commission exclude the rest of the non-residential schedules from the decoupling mechanism. Those schedules consist of relatively large industrial customers and farm irrigation customers (Schedules 12/26, 10/31, 29, 35, 40, 46 and 49). In my assessment, the decoupling mechanism is not a proper way to address conservation and revenue stability goals for those groups. Instead of decoupling, Staff recommends the Commission approve an increase in demand charges for Schedules 46 and 49, as proposed by Staff Witness Mr. Ball, to address the Company's concerns of fixed cost recovery.

Similarly for natural gas, I recommend that the Commission allow the following three natural gas rate groups to be decoupled as individual groups based on their distinctive usage patterns within the group: (1) Schedule 23 (Residential); (2) Schedule 31 (Small Volume); and, (3) Schedule 41 (Large Volume). I recommend that the Commission exclude Schedules 86/86T from the decoupling mechanism because this customer group is not suited for decoupling for the same reasons as large electric non-residential customers.

Q. Why does the non-residential customer class need to be re-grouped?

A. The non-residential customer class consists of an array of customers with very different energy usage characteristics. In foreseeing the potential problem four years ago, the Commission observed that:

> There undoubtedly is significant heterogeneity in the non-residential customer class. Members of this customer class have

> different—in some instances vastly different— levels of demand. Some non-residential customers have the capability to react nimbly to changed economic conditions, ratcheting their demand for power or gas up or down as general market conditions improve or deteriorate. Others have less flexibility. Some customers are more weather sensitive than others. Many non-residential customers undertake their own conservation efforts and are not even eligible to participate in Company conservation programs and initiatives. These factors raise questions about the suitability of decoupling that relies exclusively on average revenue per customer.[36]

As Mr. Piliaris accurately pointed out, over time, as the usage per customer for each individual non-residential group changed, there was cost shifting among schedules.[37] As such, it is important to remedy the cross subsidization problem by grouping the customers of similar characteristics together for decoupling purposes. Such remedy is consistent with the Commission's vision of decoupling: "Decoupling is a ratemaking tool used to allocate costs the Company incurs when it experiences a shortfall in fixed cost recovery. Ideally, this tool operates to assign cost responsibility in accordance with cost causation."[38]

Q. Could you elaborate upon the cross subsidization problem under the current decoupling mechanism?

A. Yes. The current decoupling mechanism puts all non-residential customers in one group, except that electric Schedules 12/26 and 10/31 are in their own separate groups. The revenue per customer target is set as the average revenue per customer

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[36] 2013 Decoupling Order, 56, ¶127.

[37] Piliaris, Exh. JAP-1T at 119:1 – 120:22.

[38] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-121697 and UG-121705, Order 09, and Dockets UE-130137 and UG-130138, Order 08, 22, ¶54 (Dec. 12, 2013) (2013 Decoupling Reconsideration Order).

for one big non-residential group. A decoupling surcharge (or credit) is calculated as the amount of the decoupling deferral divided by forecasted energy sales for the big group. Any fixed cost recovery shortfall across all non-residential customers is commingled.[39] Even if a particular customer subgroup has an increased usage per customer that meets its fair share of the subgroup's allocated revenue responsibility, the customers in that subgroup might still be required to pay a decoupling surcharge for each unit of energy they use if the usage per customer for other subgroups is rapidly declining.

Mr. Piliaris' testimony shows the change in use per customer by rate schedule.[40] For electric non-residential customers, Schedules 8/24 shows an increasing usage per customer between July 2011 and June 2016 of approximately 2 percent. Most other schedules in the group show a declining usage per customer. Industrial customers on Schedules 40 and 46/49 showed the most rapid decreases in average usage, -23 percent and -18 percent, respectively. From 2014 to 2017, all electric non-residential customers have experienced decoupling deferrals in a surcharge mode each year. Small non-residential customers on Schedule 8/24 are, therefore, paying the same decoupling surcharge per kilowatt-hour as all other non-residential customers. They should not be. These small customers would have paid smaller decoupling surcharges if they had not been comingled in a decoupling group with larger customers.[41] In contrast, Schedules 40, 46, and 49 customers would have

[39] 2013 Decoupling Reconsideration Order, 14, ¶32.
[40] Piliaris, Exh. JAP-1T at 119:1-3.
[41] *See* Liu, Exh. JL-8, showing a summary of PSE's Electric Non-Residential Proposed Grouping Backcast from PSE's Response to UTC Staff Data Request No. 231. The deferral balances for the three separate non-residential groups in PSE's backcast include the effect of 3 percent K-Factor in the rate plan.

paid higher decoupling surcharges (with one exception).[42] In essence, because smaller customers have been lumped in with larger customers, smaller users with increasing average usage (perhaps due to business growth) are subsidizing larger users with decreasing average usage (perhaps due to conservation).

Q. Would PSE's proposal to split the third electric decoupling group into three subgroups address the cross subsidization problem?

A. No. The Company's proposal would still result in an electric rate group consisting of master-metered residential multi-family dwellings on Schedule 7A, small demand general service on Schedules 11 and 25, seasonal irrigation and drainage pumping on Schedule 29, one large seasonal primary irrigation and pumping customer on Schedule 35, and all-electric schools with interruptible primary service on Schedule 43. These customers have very distinct usage characteristics and disparate growth rates: they should not be comingled into the same decoupling group.

Q. How does Staff's proposal compare to the Company's proposal?

A. Staff's proposal is similar to the Company's, in that it recommends grouping customers with similar usage pattern together. It is different because Staff recommends excluding certain large industrial and farm irrigation customers from the decoupling mechanism.[43]

[42] In the backcast, the May 1, 2017 rate for Schedules 40, 46 & 49 is slightly lower than the decoupling rate under the current decoupling design. But it is partially because the company anticipates a decrease in the number of customers for that subgroup for 2017-2018 rate year, hence lower anticipated allowed revenue.
[43] In the following discussion, I refer to the schedules that Staff recommends excluding from decoupling as "large industrial customers and farm irrigation customers." I include Schedule 29 customers in this

Q. Is Staff's recommendation to exclude certain customer classes from decoupling consistent with the Commission's policy statement?

A. Yes. The Commission's Decoupling Policy Statement specifically states that

> Generally, a full decoupling proposal should cover all customer classes. However, where in the public interest and not unlawfully discretionary or preferential, the Commission will consider a proposal that would apply to fewer than all customer classes.[44]

In fact, the Commission has already excluded large natural gas customers on Schedules 85, 85T, 87 and 87T from the decoupling mechanism because such exclusion does not negatively affect conservation achievement or PSE's fixed cost recovery.[45]

Q. Could you explain the reasons for your recommendation to exclude large industrial customers from decoupling?

A. My recommendation to discontinue the decoupling mechanisms for large industrial customers relates to the primary goals of the decoupling mechanism. My reasons are:

- Decoupling adds value to additional conservation savings for small customers, but such value is not significant for large customers.
- In practice, it is very difficult to get the decoupling mechanism right for large customers.

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terminology, even though Schedule 29 customers have much smaller usage rates than large industrial schedules. Schedule 29 usage is about 19,000 kWh annually, and it is very diverse, with a standard deviation of 27,000 kWh. Schedule 29 also has fewer than 600 customers. Therefore, Schedule 29 fits the characteristic of relatively high usage, diverse usage, and few customers.

[44] Decoupling Policy Statement, 18, ¶28.

[45] 2013 Decoupling Reconsideration Order, 27-32, ¶¶ 65-77.

- Decoupling does not adequately address the challenge of recovering fixed costs with the current rate design for large industrial customers. There are better ways to improve the Company's fixed cost recovery from those customers.

i. Decoupling Does Not Add Significant Value to Conservation Incentives for Large Industrial and Farm Irrigation Customers

Q. Could you elaborate upon the lack of conservation motivation for large customers?

A. Yes. One purpose of decoupling is to remove a utility's throughput incentives so that the utilities are indifferent to sales volume. Elimination of this throughput incentive is expected to result in the utility adopting and pursuing conservation measures more aggressively.[46]

I believe this conservation incentive benefits residential and small non-residential customers, but it is unnecessary for large customers. Large users already have a very strong motivation to curb their energy usage to reduce operational expenses. They are often more sophisticated and able to dedicate more resources to seek energy efficiency measures on their own initiatives. Decoupling, therefore, is unnecessary to spur conservation efforts because these large customers are already self-motivated to make such achievements.

[46] Decoupling Policy Statement, 19-21, ¶¶30-32.

More importantly, large users will likely quickly realize that the more energy they conserve, the higher their decoupling surcharge will be in the following year, thus providing a disincentive for pursuing conservation. This perverse incentive for large customers to moderate conservation achievement under decoupling is counterproductive to the Commission's goal of achieving increased energy conservation through revenue decoupling.

Q. Would PSE reduce its energy efficiency measures for large industrial and farm irrigation customers if those customer groups were no longer in the decoupling mechanism?

A. Staff does not believe so. Under both RCW 19.285.040 and WAC 480-109-100, all electric utilities are obligated to "pursue all available conservation that is cost-effective, reliable, and feasible." With or without the decoupling mechanism, PSE must engage in cost-effective conservation to the best of its ability. Scaling back conservation for selected groups would be contrary to Commission rule WAC 480-109-100(7), which states "a utility must offer a mix of conservation programs to ensure it is serving each customer sector."

Q. Would discontinuing the decoupling mechanism for just large industrial and farm irrigation customers negatively affect the Company's conservation achievement?

A. No. In this rate case, the Company proposes to continue its commitment to accelerate its conservation achievement by 5 percent above the levels approved by the Commission for PSE's biennial conservation target or otherwise be subject to penalties.[47] The Company also proposes an additional 5 percent commitment to its natural gas conservation program.[48] These commitments should assure the Commission that discontinuing the decoupling mechanism for large electric or gas customers will not result in a decline in the Company's conservation achievements, overall.

ii. It Is Difficult to Implement Decoupling for Large Usage Customer Groups

Q. Can you elaborate upon the difficulty in implementing a decoupling mechanism for large usage customers?

A. Yes. Based on my evaluation, decoupling is not suitable for customer groups with few customers and diverse usage patterns. There are problems with either combining them with smaller customer groups or with segregating them in single groups. Combining small and big usage schedules results in cross subsidization because these customer groups have different usage trends. Putting large users in their own decoupling group is also problematic for the following reasons.

First, revenue decoupling for a group with few customers may cause rate volatility within the group. For example, if a very large customer on the schedule leaves the group, the group's average usage per customer (hence, the actual revenue)

[47] Piliaris, Exh. JAP-1T at 144:17-21 and 145:1-4.
[48] *Id.* at 145:5-20.

will go down substantially, causing the remaining customers to pay a large decoupling surcharge in the following year.[49] The opposite could also be true: a customer could enter the schedule and cause the group to pay a much smaller decoupling surcharge the following year. Such rate volatility is very undesirable. Under PSE's regrouping proposal, the annual allowed volumetric delivery revenue per customer for the subgroup of Schedules 40, 46, and 49, would be above $155,000 per customer.[50] With Revenue per Customer at such a high level, any addition or removal of a customer with unusually low or high usage would be very problematic.

Second, it is very challenging to set a "revenue per customer" target for a small group of diverse large users based on a snapshot of the test year. Because every large industrial customer is somewhat unique, the usage per customer target for the group will be very susceptible to individual large customers' business cycles and conservation efforts. The changes in usage tend to have a bigger magnitude than the residential and small non-residential customers who have much more homogeneous usage patterns within the group and stable trends.

Third, decoupling large users' revenue does not prevent cross subsidization among customers on the same schedule because, simply, the customers on a single schedule are still quite diverse, particularly with respect to the year-over-year change in individual customers' energy consumption. Customers with growing demand for energy will end up subsidizing customers with declining demand because the

[49] Please note that one business could have multiple customer accounts with PSE. A business's decision to leave, join or switch between schedules often involves simultaneous changes to multiple accounts.
[50] Piliaris, Exh. JAP-30.

decoupling surcharge is imposed on all usage. Again, in comparison, there is much less variation (or diversity) between the average usage per customer for residential and small non-residential customer groups. Cross subsidization in these groups is minimal and decoupling surcharges or rebates can be implemented more fairly and equitably.

For these three reasons (potential rate volatility, the difficulty of setting a stable revenue per customer target, and potential cross subsidization among customers within the same group), I do not recommend the Commission approve decoupling for a rate schedule with a small number of customers and with diverse energy consumption levels.

iii. Decoupling Is an Inadequate Solution for Fixed Cost Recovery for Large Customers

Q. How does Staff propose to address the challenge of fixed cost recovery that the Company faces for very large industrial and farm irrigation customers?

A. Staff proposes that the Commission use rate design, rather than decoupling, to address the fixed cost recovery concern associated with large industrial and farm irrigation customer groups.

One important goal of decoupling is to provide the Company an opportunity to recover its fixed cost. By approving a decoupling mechanism that sets the revenue requirement at the per customer basis, the Commission reduces PSE's risk of full and timely recovery of its fixed costs and reduces volatility to the Company's cash flow.[51] However, there are alternatives to decoupling that would accomplish the same goal. In the 2013 Decoupling Order, the Commission stated:

> It may be that there are alternatives for some, or all, non-residential customers that are better suited to meeting decoupling's goals than are the current decoupling mechanisms. The Commission remains open to hearing fully supported alternative proposals for fixed cost recovery from the non-residential class of customers, or subsets of the class.[52]

As discussed above, the current decoupling mechanism is not suitable for large industrial and farm irrigation customers. The average revenue per customer target does not work well for a group with heterogeneous customers with highly variable usage patterns and a small number of customers. Variations in usage trends of those customers can lead to rate volatility and cross-customer subsidization. Additionally, because the decoupling rate is a volumetric surcharge/credit, if the large users continue to reduce their usage through energy efficiency improvement, it may become harder to fully amortize the deferral balance as time goes on.

Q. What alternative approach could we take to improve the Company's opportunity to recover fixed cost from large industrial and farm irrigation customers?

A. The Commission should, as an alternative approach to decoupling, explore rate design solutions for large industrial and farm irrigation customers to address the fixed recovery concerns.

[51] 2013 Decoupling Order, 47-48, ¶103.
[52] *Id.* at ¶129.

Q. What is Staff's recommended rate design solution for large industrial customers?

A. My colleague, Mr. Ball, has conducted a comprehensive review of the Company's cost of service, rate spread, and rate design. He proposes to eliminate Schedule 40 and increase the demand charges for Schedule 46 and 49 customers. Because demand charge revenue is more "fixed" than energy charge revenue, the Company will be able to recover their fixed cost in a more reliable manner. Mr. Ball's proposal will greatly reduce the fluctuation in revenue for Schedules 46 and 49 due to conservation or economic reasons that are outside of PSE's control. These improvements to rate design should render decoupling unnecessary for Schedules 46 and 49.

Q. Is Staff recommending changes to rate design for the other non-residential schedules it recommends excluding from the future delivery decoupling mechanism?

A. No. Staff does not propose re-structuring rates for electric Schedule 12/26, 10/31, 29, 35, 43 and gas Schedule 86 and 86T at this time. The rate structure currently in place for those customers is sufficient to allow an opportunity for fixed cost recovery.

If each of the above-mentioned schedules is placed in its own decoupling group, there may be some small divergence between the allowed revenue and the actual revenue on an annual basis. But this minor divergence is acceptable. The Commission is not required to provide an iron-clad revenue guarantee to the

Company. To the extent that the Company believes the collected revenue from these excluded schedules could still fall short of the cost of providing these customers with service, Staff suggests that the Company attempt to further improve its rate structure.

Q. Could you explain Staff's recommendations for electric Schedules 12/26 and 10/30, specifically?

A. Staff recommends these schedules be excluded in the future delivery decoupling mechanism going forward because decoupling is not necessary after the rate design change in 2013.[53]

Schedules 12 and 26 are large demand general service customers; Schedules 10 and 31 are primary general service customers.[54] These schedules currently are included in the delivery decoupling mechanism, but in their own separate groups. As PSE witness Mr. Piliaris explained, at the beginning phase of the implementation for the current decoupling mechanism, advocates for the customers served under these schedules called for higher demand charges instead of a decoupling mechanism; PSE argued that demand charges would still fall short of producing stable revenue.[55] As a compromise, demand charges were increased for those schedules and the decoupling deferrals were calculated based on the actual delivery revenue recovered from demand charges rather than energy sales.[56]

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[53] In 2013, the Commission authorized the change in rate structure for Schedules 12/26 and 10/30. Demand charges are increased and energy charges are reduced accordingly. *See* 2013 Decoupling Reconsideration Order, 6-14, 32, ¶¶ 11-33, 76.
[54] Schedules 12 and 26 have the same rates. Schedules 10 and 31 have the same rates. Customers in Schedules 12 and 10 are residential and farm customers that qualify for Bonneville Power Administration's residential exchange credits.
[55] Piliaris, Exh. JAP-1T at 112:4-18.
[56] *Id.*

Staff considers the rate restructure of Schedules 12/26 and 10/31 a success. The increased demand charges better aligned rate design with the underlying cost of service for these schedules and can serve as a model for decoupling other PSE non-residential electric rate classes, as the Commission hoped three years ago.[57] As a result of the rate restructure, the deferral balances and surcharges per kilowatt for these two groups were very small compared to other decoupled groups.[58] Staff believes that the rate restructure has accomplished the goal of fixed cost recovery. Customers on these schedules do not, therefore, need to be decoupled going forward.

Q. Could you explain Staff's recommendations for electric Schedules 29, 35, 43 and gas Schedules 86/86T, specifically?

A. These schedules are all unique in their own ways. They all have a relatively small number of customers and their usage trends vary. Schedule 29 has 500 to 600 irrigation and pumping customers; Schedule 35 has only one very large primary irrigation and pumping customer. The usage per customer for both customers has increased over the years.[59]

Electric Schedule 43 is interruptible service for all-electric schools. It currently has 158 customers. Usage per customer for Schedule 43 has trended downward in recent years, faster than its most comparable customer group,

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[57] 2013 Decoupling Reconsideration Order, 8, ¶ 18.

[58] The four year average of decoupling surcharges for Schedules 12/26 and Schedules 10/31 between 2014 and 2017 are $0.88 per Kilowatt (KW) and $0.84 per KW, respectively. The annual decoupling surcharges include the effect of the annual 3 percent K-factor increase. Without the K-factor, customers on these schedules would have paid an even smaller surcharge or gotten a credit because the usage per customer for these schedules has been trending upward during the last three years.

[59] Piliaris, Exh. JAP-1T at 119, Table 13. It shows that the usage per customer for these two schedules have increased by over 18 percent from July 2011–June 2012 to July 2015–June 2016.

Schedules 11/25.[60] Schedule 86 serves 250 - 300 customers with limited interruptible gas service with a firm option for boilers, gas engines or schools; Schedule 86T has one to three distribution transportation customers for the equivalent service. While Schedule 86 customers show a reduction in usage per customer, Schedule 86T customers show a significant increase in usage per customer.[61]

At this point, it is difficult to predict revenue volatility from these schedules. Staff recommends not to mix these schedules with other schedules because the customer characteristics are very different. Staff also recommends excluding these schedules from the delivery decoupling mechanism to afford the opportunity for the Company to examine the rate design of these schedules. The Company can monitor the usage pattern of these customers and assess whether the current rate structure for electric Schedules 29, 35, 43 and gas Schedules 86/86T needs to be improved.

Q. What is your recommendation on the decoupling regrouping issue?

A. Staff recommends the Commission continue to implement the delivery decoupling mechanism on small residential and non-residential customer groups but place the non-residential customer groups with similar usage patterns in separate groups, as I outlined at the beginning of this section. Staff recommends the Commission discontinue the delivery decoupling mechanism on large industrial and farm irrigation customer groups, specifically, electric Schedules 12/26, 10/31, 29, 35, 40, 43, 46 and 49, and gas Schedules 86/86T.

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[60] *Id.*
[61] *Id.*

2. Fixed Production Costs Should be Decoupled Based on Revenue per Group and not on Revenue per Customer

Q. What is "Fixed Production Cost?"

A. Ms. Kathy Barnard provided a description of "Fixed Production Costs" in her testimony in UE-160459, wherein the Company requested, and was granted by the Commission, approval of its power cost adjustment mechanism annual report for 2015. Ms. Barnard said:

> For PCA calculation purposes, fixed costs are power production related costs and rate of return. Power production related costs from the most recent general rate case or power cost only rate case are included and do not change from what was approved. These costs are related to production plant, and specifically identified transmission plant and include the associated return on, depreciation, production payroll overhead and taxes, energy taxes and insurance. Other fixed costs include FERC Accounts 557 Other production expense, Hydro and Other Production O&M, and 500 KV O&M. Regarding the rate of return, the approved rate from the most recent general rate case or other proceeding is applied as appropriate in the PCA period."[62]

Staff concurs with Ms. Barnard's description.

Q. What is the issue regarding fixed production costs recovery?

A. Prior to August 2015, both fixed and variable production costs were recovered on a dollar per megawatt hour basis through the Power Cost Adjustment (PCA) mechanism, subject to specific dead band and sharing band provisions. The Company is allowed to true-up fixed production costs for load variations. The

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[62] *In the Matter of the Petition of Puget Sound Energy for Approval of the 2015 Power Cost Adjustment Mechanism Report*, Docket UE-160459, Barnard, Exh. KJB-1T at 5:6-15 (internal citations omitted).

Commission approved a multi-party settlement in 2015 that moved the recovery of fixed production costs out of the PCA and allowed PSE to propose collecting the fixed production costs through the decoupling mechanism if it continues.[63] Based on my understanding, the intention of separating the recovery of fixed and variable production costs is to simplify the PCA so that it only deals with variable production costs, over which the Company has some control. Not all parties agreed that fixed production costs would be included in the decoupling mechanism.

According to the 2015 settlement agreement, the new PCA mechanism was supposed to take effect in January of 2017. The settlement agreement allows PSE to file an accounting petition to request deferral of revenue variances associated with the recovery of fixed production costs to bridge the timing difference between implementation of the changes to the PCA mechanism on January 1, 2017, and the start of the rate year for PSE's next general rate case, by which time the continuation of the electric decoupling mechanism will be decided.[64] On September 30, 2016, PSE filed such an accounting petition. On November 10, 2016, the Commission approved that petition, which allows PSE to defer the revenue variances associated with fixed production until December 31, 2017, when rates from the current general rate case will go into effect.[65]

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[63] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-130583, Order 07, UE-130617, Order 11, UE-131099, Order 07, and UE-131230, Order 07 (Aug. 7, 2015). Settlement Stipulation pages 4-5 specify costs that are classified as "Fixed Production Costs" and are carved out of the PCA imbalance calculation. I would like to note that the return on the authorized production-related regulatory assets was considered fixed under the new classification.

[64] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-130583, UE-130617, UE-131099, and UE-131230, Settlement Stipulation, 7, ¶4 (Mar. 27, 2015).

[65] Dockets UE-161135 and UE-161112.

Q. What is the Company's proposal, regarding fixed production costs?

A. The Company proposes a decoupling mechanism to recover fixed production costs in a similar fashion as delivery costs. The Company proposes to keep fixed production costs as a distinct cost category from delivery costs in the calculation of Allowed Revenue per Customer.[66] The Company proposes to use each decoupled customer group's relative contribution to the "peak credit" allocation factor to allocate the Allowed Revenue to all decoupling groups.[67]

Q. What is Staff's recommendation?

A. Staff agrees with the Company that we must separately identify the Allowed Revenue and separately track deferral for delivery costs and for fixed production costs in the decoupling mechanism. There is good reason to do this. By definition, fixed production costs are of a different nature than distribution costs. Keeping track of these records separately, as the Company and Staff recommend, will enhance the record's transparency and also make it easier for the Company and other stakeholders to examine trends and identify any problems that may develop.

Staff also agrees with the Company's proposed method to apply the peak credit method to calculate the Allowed Revenue for each decoupled group. It is consistent with the methodology the Company uses in its cost of service study.

However, as discussed below, Staff does propose one modification to the decoupling mechanism for fixed production costs.

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[66] Piliaris, Exh. JAP-1T at 128:18-21. Also see the mock filing in Exh. JAP-41.
[67] *Id.*

Q. What is Staff's proposed modification?

A. Staff recommends the Commission set the total Allowed Revenue for fixed production costs recovery per decoupled group at the level the Commission authorizes in this general rate case. The decoupled groups should be the same as Staff recommended for the delivery decoupling mechanism. This is a change from the current methodology used for the delivery decoupling mechanism, wherein the Allowed Revenue is equal to Allowed Revenue per Customer multiplied by the number of customers.

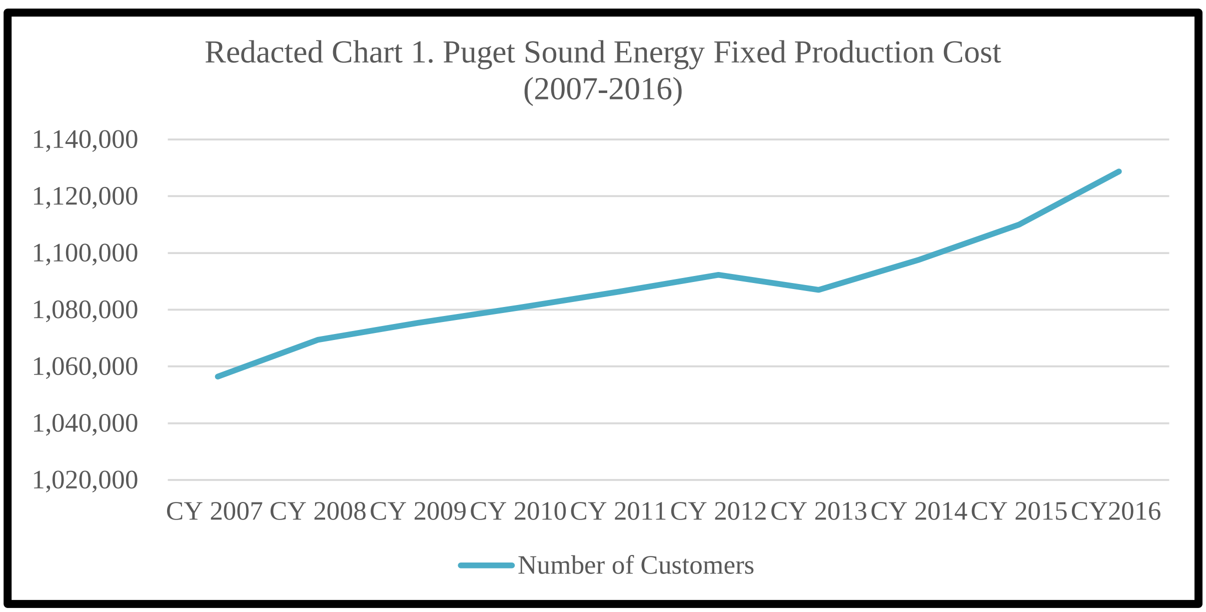
Q. Why is Staff's proposal preferable to the current Revenue per Customer approach?

A. The current decoupling mechanism for recovery of delivery cost adopts a Revenue per Customer approach. It is based on the assumption that there is cost associated with serving each additional customer and that the allowed revenue should follow the cost. There is a correlation between delivery costs and the number of customers. Typically, the Company will need to invest in lines and feeder plant to serve customers in a new development. The Company will also incur costs (e.g., line maintenance, customer service, general administrative costs) to serve the additional customers. As Ms. Barnard explained in her testimony, the Company's operating expense has increased at a growth rate of 2.0 percent between 2011 and June 2016, outstripping the customer count growth rate of 0.8 percent.[68] The Revenue per

[68] Barnard, Exh. KJB-1T at 7:10-11.

Customer approach works well when the delivery costs and customer counts both trend upwards.

Such a correlation does not exist between fixed production costs and customer counts. When the Company needs to serve increased load due to customer growth, it has the choice of whether to build new generation plants or buy power from the market. But a bigger customer base, or higher load, does not necessarily mean higher fixed production costs. Fixed production costs, at best, increase in big steps, when the load demand grows over a long time period, as shown in my trend analysis in Exh. JL-7C. The following graph illustrates the Company's fixed production costs and the number of customers in the last ten years.[69] This chart and the cost information in it are confidential.



[69] The fixed production costs are compiled from annual Power Cost Adjustment filings from 2008 to 2017. Under the settlement agreement in UE-1301617, certain cost items were re-classified between the fixed and variable cost categories. The information here reflects the re-classification. The customer growth data is from PSE Response to UTC Staff Data Request No. 265.

As seen in this graph, the growth in total fixed production costs and the growth in customer base do not correlate. In 2013, for example, fixed production costs increased by 11 percent while the Company lost customers by 0.5 percent. In more recent years, fixed production costs are trending downward even though the customer base continues to grow. Therefore, it is not appropriate to implement a decoupling mechanism for fixed production cost if it is based on the revenue per customer approach; fixed production costs simply do not depend on customer counts. Linking fixed production costs to customer counts would provide the Company with additional revenues to cover fixed production costs that do not exist.

Q. Why would linking fixed production costs to customer counts be inappropriate?

A. For the Revenue per Customer approach to work properly, the cost and customer base growth have to trend in the same direction. Otherwise, we will end up with a mismatch. This is always in the Company's favor: when costs increase, the Company can initiate another general rate case or a power cost only rate case to reset the revenue requirement on a per customer basis in order to recover the increased costs; but when costs decrease, the Company can over-recover the costs because its Allowed Revenue will increase as the customer base grows. In the latter instance, ratepayers would be overpaying the Company for fixed production costs. The rates would not, in Staff's opinion, be fair, just, and reasonable.

To help illustrate my point, please look to Table 3. It shows the projected increase in Allowed Revenue under the Company's proposal for 2018 as compared to the test year, September 2015 to October 2016.[70] If the Commission were to decouple the Company's fixed production costs recovery based on Revenue per Customer, it would authorize the Company to collect $12.8 million more (2.2 percent increase) in fixed production revenue over two and a quarter years. In other words, if the annual customer growth rate remains at one percent, the Company would collect one percent more revenue, approximately $6 million, each year going forward while the actual production-related fixed costs would likely not grow, but could decrease. While the numbers in the table below are not necessarily the final revenue requirement the Commission will approve, it illustrates the potential magnitude of the mismatch.

Table 3. Increase in Allowed Revenue under PSE's Proposal

Allowed Revenue in Decoupling	Test Year	2018 Calendar Year	Increase	Increase %
Delivery	$ 623,553,409	$ 637,666,358	$ 14,112,949	2.3%
Fixed Production	$ 579,720,787	$ 592,549,476	$ 12,828,688	2.2%
Total	$ 1,203,274,196	$ 1,230,215,833	$ 26,941,637	2.2%
Number of Customers	1,107,790	1,136,909	29,119	2.6%

Q. Why is the cost trend relevant in the context of this general rate case?

A. In addition to recognizing that PSE's fixed production costs are not growing, decoupling the Company's fixed production costs in the context of the retirement of Colstrip Units 1 & 2 warrants special attention. If the Commission authorizes the Company's proposal to depreciate Colstrip Units 1 & 2 over the next 4.5 years, the Company's fixed production rate base will rapidly decline, without the addition of

[70] Piliaris, Exh. JAP-41.

new plant of a similar scale. In that scenario, the Allowed Revenue for fixed production should be not be held at a constant level; it should decrease; and it certainly should not be allowed to increase based on customer growth. Staff witness, Mr. Chris McGuire, recommends that the Commission reduce the associated remaining plant balance to $30.6 million, a major reduction to the Company's production rate base. If his recommendation is adopted, the annual depreciation will be substantially lower, and Staff's concern about the rapid decline in production rate base will be alleviated.

Q. How does Staff recommend the Commission set the Allowed Revenue target for PSE's fixed production decoupling mechanism?

A. Staff recommends that the Commission set the Allowed Revenue for the fixed production decoupling mechanism at the level determined by the Commission in this general rate case without any tie to the growth or decline in customer base. Staff's recommendation is consistent with the 2015 Settlement Agreement and aligned with the Company's proposal: the recovery of fixed costs will be decoupled from the energy sales (thus, addressing the throughput incentive); and, the rates will be trued-up every year for load variances to reflect the difference between the Allowed Revenue and the actual collected revenue, similar to what was accomplished in the PCA mechanism previously. Because the fixed production costs are largely "fixed," Staff is comfortable advocating for cost recovery through a true-up mechanism with a pre-determined revenue requirement.

Staff's proposal differs from the way fixed production costs are treated in the previous PCA mechanism: the decoupling mechanism will allow the Company to amortize the deferral because the load variance is trued-up annually. In the previous PCA, the deferral of fixed production costs was combined with the deferral of variable production costs, was subject to the dead bands and sharing bands, and was not trued-up until the combined deferral triggered the pre-determined threshold.

Staff's proposal also differs from the Company's in that it does not allow for a growth in revenue due to a growth in customer base. This means that the Company's Allowed Revenue for fixed production will not increase until the Company can demonstrate an increase in actual costs in the next general rate case or in a power cost only rate case.

Q. Will Staff's recommendation for fixed production costs affect other revenue adjustments in this rate case?

A. Yes. It will affect the calculation of the production factor adjustment.

Q. What is the production factor adjustment?

A. The Company applies a production factor to adjust the Company's production-related rate base and expenses at the forward-looking rate year level back to the test year level. The adjustment allows the matching of the relationship between future sales to the production rate base and production expenses.[71] The intent is to include a predetermined reduction to rates based on a relevant factor – either delivery load or

[71] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08, 113, ¶326 (May 7, 2012).

customer counts – so that the Company avoids collecting more than what is allowed solely as a result of higher volumes or customer growth.[72] As the load or the number of customers grows in the rate year, the Company's collected revenue will match up with its projected rate year costs. The reverse would apply in a period when load or customers are expected to decline.

Q. How does the impact on net operating income and production rate base differ between the Company's and Staff's production adjustment?

A. Under the Company's proposal, fixed production costs will be decoupled on a dollar per customer basis. The Company projects a 2.5 percent customer growth between the test year and the rate year. Therefore, all fixed production expenses as well as production rate base are scaled back by the same percent to reflect the costs necessary to serve the number of customers in the test year. The Company's production adjustment increases its net operating income by $3,129,292 and reduces its production rate base by $54,762,869.[73]

Under Staff's proposal, the recovery of fixed production costs will be decoupled based on a fixed revenue target. This essentially sets the fixed production factor at 0 percent. There will be no production adjustment except for the Montana Energy Tax, which is adjusted based on a variable production factor. This adjustment increases the Company's net operating income by $36,105 (solely due to the Montana Energy Tax). There is no adjustment to the Company's production rate base under Staff's proposal.

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[72] PSE's Response to UTC Staff Data Response No. 439.
[73] Barnard, Exh. KJB-14, Adj. 14.13.

Q. Does Staff's recommendation on the production factor adjustment affect the Company's Allowed Revenue in the rate year?

A. No. If the Company's forecast on customer growth is correct, the Company and Staff will arrive at the exact same Allowed Revenue for fixed production costs in the rate year. Under the Company's proposal, it sets the Revenue per Customer based on the fixed production revenue requirement and the number of customers in the test year. Then it will "grow into" the Allowed Revenue (Revenue per Customer multiplied by the number of customers in the rate year) as its customer base expands. Only after the rate year will Staff's proposal differ from the Company's: under Staff's proposal, the Allowed Revenue for fixed production will not grow or decline as the customer base changes until it is reset in a general rate case or power cost only rate case.

3. Normalizing Adjustments for Earnings Test Should Remain

Q. What is a normalizing adjustment?

A. In general, a normalizing adjustment removes the effect of abnormal weather and events on the Company's booked revenues and expenses. For example, in Section II of my testimony, I explained how weather normalization is an adjustment to a company's test year revenue to reflect a level of sales under normal weather conditions.

Normalizing adjustments are required in the regulated energy utilities' Commission Basis Report (CBR).[74] They include adjustments to results of operations "for any material out-of-period, nonoperating, nonrecurring, and extraordinary items or any other item that materially distorts reporting period earnings and rate base" and adjustments to booked revenues and power supply expenses "to reflect operations under normal temperature and power supply conditions before the achieved return on rate base is calculated."[75] CBRs require normalizing adjustments because they help to provide an annual snapshot of the Company's earnings performance consistent with the most recent general rate case. Without normalizing adjustments, there would be no way to judge whether the Company achieved any efficiency gains because the operating income would not reflect the level achievable under normal conditions.

Q. What is earnings sharing?

A. Earnings sharing between a company and its ratepayers is a predetermined arrangement of how any earnings of the company beyond a specified level will be divided, with a portion remaining with the company and the other portion being returned to ratepayers. This creates incentives for a company to pursue business actions that would result in greater revenue, but is fair to ratepayers as they also share in the benefits of those decisions.

[74] WAC 480-90-257.

[75] WAC 480-90-257.

Q. How has earnings sharing been built into the current decoupling mechanism?

A. The current mechanism requires the Company to equally share any earnings in excess of its authorized rate of return with ratepayers. On the one hand, this sharing mechanism incentivizes the Company to achieve greater operational efficiency and allows it to retain a share of any excess earnings, while on the other hand allowing ratepayers to also benefit from achieved efficiency. The earnings test is based on PSE's normalized operating income as reported in its annual CBR.

Q. What is the Company's proposal for adjusting the sharing mechanism?

A. PSE witness Dr. Doyle proposes to remove all normalizing adjustments from the result of operating income for the purpose of the earnings test calculation. These normalizing adjustments include weather normalization, certain expenses (e.g., bad debt, pension plan expense, injuries and damages and rate case expenses), and removal of non-recurring transactions.[76] Dr. Doyle argues that these normalizing adjustments unfairly cause the Company to share excess earnings that it did not earn on an actual non-normalized basis.[77]

Q. Does Staff support the Company's proposal?

A. No. The Company's proposal contradicts the intent of the earnings sharing mechanism. Staff witness Mr. Schooley discusses the normalizing adjustments in detail and concludes that the only adjustment that could potentially impact the

[76] Doyle, Exh. DAD-1T at 14:1 – 25:18.
[77] *Id.* at 20:16 – 21:6.

Company's earnings outlook is the weather normalization adjustment on variable power revenue.[78] Without the normalizing adjustments, however, the CBR operating results would be confounded with the effects of weather and special or extraordinary events and expenses. Also, the "earned" rate of return without any normalization adjustment could not be compared to the authorized rate of return benchmark because the benchmark is based on normalized operational results. Ultimately, the Commission could have little to no confidence that the earnings sharing mechanism was providing ratepayers with any share of the benefits from the Company's improved earnings performance. Ensuring ratepayers are actually sharing the benefits from the Company's improved earnings performance is essential to monitoring and verifying the efficacy of the decoupling mechanism.

4. Do Not Implement a Dead Band for Earnings Sharing

Q. What is the Company's proposal for a dead band for earnings sharing?

A. Mr. Doyle proposes to include a 25 basis point dead band or alternatively, no less than 14 basis points, in the earnings sharing test in the decoupling mechanism.[79] Under the proposal, 50/50 sharing would begin only after PSE over-earned its authorized rate of return plus 25 basis points.[80] In practical terms, this means that PSE would keep the entirety of any excess earnings up until the raised threshold, and

[78] Schooley, Exh. TES-1T at 14:1 – 16:7.
[79] *Id.* at 25:12-18.
[80] *Id.*

only after that threshold had been exceeded would the Company begin sharing earnings with ratepayers as originally contemplated in the decoupling mechanism.

Q. Does Staff support the Company's proposal?

A. No. As Staff witness Mr. Schooley discussed, over the years, the Commission has provided numerous regulatory mechanisms to accommodate the risks the Company faces and provided PSE with an opportunity to earn its return.[81] The return on equity that the Commission ultimately authorizes in this rate case will sufficiently compensate the Company's shareholders.

As Mr. Doyle accurately described, the dead band proposal was in PSE and NWEC's initial decoupling proposal in 2012, but was rejected by the Commission for the purpose of calculating earnings sharing.[82] The Commission viewed the 9.8 percent return on equity to be at the higher end of the range of reasonableness.[83] The implication is that, given a moderately high return on equity, the Company is already enjoying profits beyond what it would enjoy if the authorized return on equity were at the midpoint of reasonableness.

We are in a similar situation now, where the Company requests keeping additional profits while also proposing a return on equity that is objectively high. The Company's profits do not need to be expanded beyond what the Commission determines is appropriate. The current 50/50 earnings sharing agreement provides ample incentive for the Company to operate more efficiently because it allows PSE

[81] Schooley, TES-1T at 11:4 - 12:17, 16:14 - 17:3.
[82] *Id.* at 14:15-18.
[83] 2013 Decoupling Order, 71-72, ¶¶164-165.

to keep a portion of the excess earnings beyond its authorized rate of return. Providing the Company with a dead band simply provides an avenue by which the Company avoids sharing in gained efficiencies. The Commission should reject the Company's proposal.

5. Renew the Decoupling Mechanism for Another Four Years

Q. What is the Company's proposal for renewing decoupling?

A. The Company proposes to make the decoupling mechanism permanent and continue until such time as PSE proposes, and the Commission approves, to have it discontinued or modified.[84]

Q. Does Staff support this proposal?

A. No. Staff believes the Commission should only authorize the decoupling mechanism for another four years.[85] At the end of the four year period, the Company should file a petition to the Commission to determine whether the decoupling mechanism should be continued or modified, regardless the timing of the future general rate cases. This petition could also be included as part of a general rate case.

Staff's recommendation is consistent with the Commission's Decoupling Policy Statement, wherein the Commission states that

> The Commission will generally approve a full decoupling mechanism for the period required to achieve its objectives or until the filing of a utility's next general rate case. Under either

[84] Piliaris, Exh. JAP-1T at 146:8-14.
[85] Staff believes a time frame of three to five years is generally appropriate.

> circumstance, the burden is upon the utility to demonstrate the continued need for the mechanism.[86]

There is always the possibility that circumstances will change such that decoupling is no longer supportable, and the Commission should maintain its flexibility to address changes over time. It is important for stakeholders to continue to monitor all aspects of the decoupling mechanism and identify potential problems. Because the delivery revenue mechanism is based on Revenue per Customer, it is important to have a general rate case in no later than four years to examine whether the revenue target is still appropriate and whether the relationship between distribution cost and the number of customers still holds. Decoupling is only one of the tools in the Commission's regulatory toolbox to address throughput incentives and revenue stability. Setting a timeframe for renewal is appropriate; making decoupling permanent is not.

6. Change Calculation of "Current Revenue" for Soft Cap Test

Q. What is the Company's proposal?

A. The Company proposes to calculate "current" revenue for each rate group as a product of current rates and weather-normalized billing determinants in the prior calendar year. Currently, PSE uses normalized revenue from its CBR for the rate test, but since these revenues are not decomposed at the schedule level, the Company takes multiple steps to get to schedule-level revenue, including updating Schedule 142 revenue.

[86] Decoupling Policy Statement, 19, ¶28.

Q. Does Staff support this proposal?

A. Yes. Staff believes the proposed method simplifies the calculation and gets to the same results. It is also the same method that Avista Corporation uses for its decoupling rate test.[87]

7. Increase Soft Cap to Five Percent

Q. Could you please describe the Company's proposal to increase the soft cap percentage?

A. The current mechanism limits the decoupling rates to 3 percent of the total bill for each decoupled rate group. The Company proposes to increase the soft cap to 5 percent for the residential gas group and all electric groups. This increase to the soft cap will be applied to delivery and fixed production decoupling rates, combined. The Company expressed concerns that with a 3 percent cap the Company was not able to fully amortize the deferral balance, particularly for gas residential groups.[88] Generally Accepted Accounting Principles (GAAP) require that revenues accrued in connection with a revenue recovery mechanism must be collected in cash within 24 months from the close of PSE's fiscal year; the portion of revenue that will be collected beyond 24 months cannot be recognized as earned revenue for the fiscal year.[89] The Company does not propose a minimum rate trigger percentage to amortize deferred revenue.

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[87] *See* Avista Corp. Electric Tariff, WN U-28, First Revision Sheet 75E.
[88] Doyle, Exh. DAD-1T at 11:15-24.
[89] ASC 980-605-25-4 (Regulated Operations Revenue Recognition).

Q. Does Staff support this proposal?

A. Yes. Staff supports the Company's proposal to raise the soft cap to 5 percent. However, Staff recommends applying the same soft cap to all electric and gas decoupled rate groups for the sake of simplicity. Staff agrees with Mr. Piliaris that a higher rate trigger will better align cost causation and cost recovery while also improving intergenerational equity.[90] The soft cap level does not change the amount of decoupling deferral revenue the Company is authorized to collect from customers; it only affects the timing of the recovery.

There are good reasons not to prolong the time period from which the decoupling deferral can be recovered. It contradicts the matching principle of revenue and cost. It also distorts the equity between existing customers and newer customers because the latter would be paying for the deferral from more than two years ago. In addition, customers will be paying interest on the deferral. A delayed decoupling surcharge also sends confusing price signals to customers. Therefore, Staff believes raising the soft cap is appropriate. Having a 5 percent soft cap will still provide protection from rate surges. On natural gas bills, the purchased gas cost will continue to be low for the near future. This will partially mitigate any potential high decoupling surcharges after a warm winter.

Staff also agrees with the Company that a minimum rate trigger percentage is not necessary. Trueing-up the decoupling deferral each year is consistent with the revenue-cost matching principle and with the current practice regarding the purchased gas costs and tariff revisions for other tracker mechanisms.

[90] Piliaris, Exh. JAP-1T at 135:5-17.

Q. Can the potential rate increase due to decoupling be mitigated?

A. Yes. To mitigate the impact of potential rate increases caused by a decoupling deferral, we need to recognize the root cause: recovering fixed costs from volumetric charges is very challenging. Staff Witness Mr. Ball proposes a minimum charge on electric residential bills and an increased basic charge for natural gas service.[91] The proposal will provide the Company with a significant amount of additional fixed revenue. If adopted, the volumetric portion of delivery revenue subject to weather and conservation influences will shrink significantly. The decoupling deferral will be less volatile. Staff is confident that the decoupling surcharge is less likely to cause a big rate increase in the future if Mr. Ball's proposal is adopted.

8. Change Basis to Allocate Shared Earnings

Q. Could you please describe the Company's proposal?

A. The Company proposes to allocate shared earnings to customers in relation to their allowed revenue rather than based on their volumetric revenue.[92] The reason is that earnings are directly linked to the allowed revenue PSE books rather than the actual volumetric revenue it receives.[93]

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[91] *See* Ball, Exh. JLB-1T at Section V.
[92] Piliaris, Exh. JAP-1T at 138:9 – 139:5.
[93] *Id.*

Q. Does Staff support this proposal?

A. Yes. It is an improvement to the calculation as the proposal would allocate shared earnings to each rate group based on their contribution to the total booked revenue. PSE already used this method in both its 2016 and 2017 decoupling filings.[94] The Commission should support this method as the appropriate way to allocate earnings.

9. Change the Calculation of "Actual Revenue" for Non-Residential Gas Customers

Q. Could you please describe the Company's proposal?

A. Currently, PSE determines the "actual" revenues by multiplying a blended average margin rate by volumetric sales.[95] Going forward, PSE proposes to use the actual margin revenue for non-residential gas customers. It would be accomplished by multiplying the actual base rates for both volumetric and demand charges by the appropriate billing determinants.[96]

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[94] *See Puget Sound Energy, Inc.'s Proposed Revisions to Rates Under Electric Schedule 142, Revenue Decoupling Adjustment Mechanism*, Docket UE-160367 (Mar. 31, 2016); *Puget Sound Energy, Inc.'s Proposed Revisions to Rates Under Natural Gas Schedule 142, Revenue Decoupling Adjustment Mechanism*, Docket UG-160368 (Mar. 31, 2016); *Puget Sound Energy, Inc.'s Proposed Revisions to Rates Under Electric Schedule 142, Revenue Decoupling Adjustment Mechanism*, Docket UE-170227 (Mar. 31, 2017); *Puget Sound Energy, Inc.'s Proposed Revisions to Rates Under Natural Gas Schedule 142, Revenue Decoupling Adjustment Mechanism*, Docket UG-170228 (Mar. 31, 2017).

[95] Piliaris, Exh. JAP-1T at 139:12-17.

[96] *Id.* at 139:18 - 140:1.

Q. Does Staff support this proposal?

A. Yes. This will be an improvement to the calculation. As the Company pointed out, the blended average margin rate currently used for the deferral calculation was tied to PSE's last rate case.[97] This blended average may have deviated from the actual margin because customers' usage and demand charge patterns have changed during the past three and a half years. Going forward, actual revenue should be calculated from the actual rates and billing determinants.

10. Accept Additional Commitments for Decoupling

Q. What other commitments does PSE propose to support the continuation of its decoupling mechanism?

A. PSE proposes to continue its commitment to achieve conservation savings by additional five percent above the levels approved by the Commission for PSE's biennial conservation target.[98] This commitment is now extended to gas conservation achievements as well, with specific penalties in the event that the commitments are not met.[99] PSE also commits to maintain the $500,000 per year additional funding for its low-income weatherization program.[100]

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[97] *Id.* at 140:2-10.
[98] *Id.* at 144:17 - 145:4.
[99] *Id.* at 145:5-20.
[100] *Id.* at 146:1-5.

Q. What is Staff's position on these commitments?

A. Staff supports these proposed commitments. These extensions of the Company's commitment in the current decoupling mechanism are consistent with public interest and should be continued.

IV. PSE HELP PROGRAM FOR LOW INCOME BILL ASSISTANCE

Q. Could you please provide an overview of PSE's Low Income Bill Assistance Program?

A. Yes. PSE has a Home Energy Lifeline Program (HELP) that provides bill payment assistance to eligible low income customers. HELP is funded by PSE ratepayers through Low Income Tariff Schedules 129 (electric) and 1129 (gas), currently budgeted at about $22.9 million for 2016 program year. PSE contracts with 11 local Community Action Agencies (CAAs) to determine customer eligibility and grant amount. HELP works in complement with the federal Low-Income Home Energy Assistance Program (LIHEAP) to provide vital financial assistance to disadvantaged populations to reduce their energy bills. In the 2014-2015 program year, PSE spent a total of $18.6 million through HELP for both electric and gas, $14.5 million of which were direct grant benefits to 28,567 electric customers and 8,620 natural gas customers.[101] The average annual grants were $420 for electric and $309 for gas.[102] During the same time period, PSE customers received approximately $8.6 million in

[101] PSE Revised Response to UTC Staff Data Request No. 120.
[102] PSE Revised Response to UTC Staff Data Request No. 120.

LIHEAP benefits.[103] Over 30,000 of PSE's electric customers and over 9,000 of its gas customers benefited from energy assistance from HELP and/or LIHEAP.[104]

Q. Is it important that PSE continue its HELP funding with the proposed increases?

A. Yes. HELP has provided substantial benefits to its low income ratepayers. It not only alleviates low income households' energy burden, keeping fundamental utility service available, it also benefits general ratepayers by reducing bad debt and the costs associated with service disconnection/reconnection and debt collection. It is important that the benefits flowing to both general ratepayers and to low income households through HELP continue. HELP support could become even more crucial for assisting low income ratepayers should federal LIHEAP funding ever become uncertain.

Q. What do you think of HELP, in general?

A. Staff applauds PSE's achievements. The Company has actively managed the program to optimize the benefits for its low income ratepayers. The benefit formula is carefully designed to work in sync with the LIHEAP grant formula. The Company has also worked closely with CAAs to remove administrative hurdles and allow CAAs more flexibility.[105] The Company also keeps track of each CAA's

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[103] PSE Response to UTC Staff Data Request No.119.

[104] PSE Response to UTC Staff Data Request No.121.

[105] For example, the Company allows CAAs to provide customers with PSE Help benefit when the agency does not process LIHEAP grant. In the 2016-2017 program year, the Company raised the $300 credit threshold, below which a low income household cannot receive HELP grant, to $600. It was to avoid the same applicant having two appointments with the CAA in the same program year.

expenditures to ensure the administrative costs are appropriately spent. I believe all of these factors are contributing to PSE's successful program.

Q. What are PSE's proposals with regard to HELP in this general rate case?

A. Staff's understanding is that PSE consulted with the Energy Project, a central liaison of local CAAs, before making its proposals in this case. Ms. Sasville outlined PSE's four proposals on the low income bill assistance.[106] The Company proposes to:

1. Increase the annual funding level by double the corresponding overall percent rate increase to the residential customer class approved by the Commission in this case; but the funding level would remain the same as the previous program year in the event of an overall rate decrease to the residential bill.
2. Adjust the HELP funding distribution ratio between electric and gas customers from 75/25 to 80/20.
3. Allow CAAs to certify eligible low income households with stable income (e.g., seniors or disabled individuals on a fixed income) every two years rather than every year.
4. Change the income eligibility threshold from 50 percent of area median income to 150 percent of the Federal Poverty Line (FPL).

[106] Sasville, Exh. SMS-1T at 4:3 - 8:2.

Q. Does Staff support PSE's proposals?

A. Yes, Staff supports all of these proposed changes with regard to HELP, but with a minor clarification to the first proposal, which I will explain below. Staff believes these proposals are consistent with the public interest.

Q. What minor clarification does Staff recommend for the HELP funding level?

A. The Commission approved $20.2 million as HELP base funding in PSE's 2011 rate case.[107] In the 2013 Decoupling Order, the Commission authorized "an additional amount of $1.0 million per year should be added to PSE's low income bill assistance program."[108] While Ms. Sasville did not specifically talk about it in her testimony, Staff's understanding is that this $1 million additional funding will continue. Therefore, the total funding available each year going forward should be $21.2 million, plus any supplemental increase associated with energy rate changes each year, and any carry-over funding balance from previous program years. Staff recommends the Commission clarify in its order that the $1 million authorization from the 2013 Decoupling Order will be retained in future HELP funding.

Q. Is it necessary to increase the level of HELP funding by twice the percentage of the residential rate increase?

A. Yes. Staff agrees that an increase in HELP funding tied to the future residential rate increase is necessary. The low income ratepayers are PSE's most vulnerable

[107] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08, 133-134, ¶¶373-376 (May 7, 2012).
[108] 2013 Decoupling Order, 78, ¶182.

customers. Any rate increase puts a disproportionately larger burden on low income customers because they are least able to afford a bill increase, especially in areas that also have a quickly rising cost of living. Also, these customers usually have the least means to conserve their energy use because they often times do not own their residence and/or are living in older housing stocks. The proposed level of increase is also consistent with the Commission's decisions in the 2013 PSE Decoupling Order[109] and in the Avista Corporation's (Avista) and Cascade Natural Gas Corporation's (Cascade) Decoupling Order.[110]

Q. What is your position on the proposed adjustment to the distribution ratio of HELP funding to electric and gas programs?

A. I agree with Ms. Sasville's assessment that 80/20 percent ratio better aligns with the actual utilization of the fund in current years and that the percentage should be closely monitored and adjusted as needed in the future. The adjustment will make more funds available for PSE's electric customers who currently have a higher demand for energy assistance than gas customers.

Q. What is your position on the two-year certification?

A. I agree that the optional two-year certification for fixed-income households could free up CAA's sources and make more appointments available to new applicants, but the proposal has limitations. A lot of low income customers apply for both LIHEAP

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[109] 2013 Decoupling Order, 75-76, ¶¶174-177.

[110] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-150204 and UG-150205, Order 05, 80, ¶232 (Jan. 6, 2016); *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp.*, Docket UG-152286, Order 04, 4-5, ¶12 (Jul. 7, 2016).

and HELP benefits at the same time. Those customers will still need to make appointments with CAAs for LIHEAP benefits every year even if they only need to do so for HELP benefits every two years. This may cause customer confusion. In addition, PSE HELP benefits apply towards a household's total annual PSE energy cost after excluding annual heat cost reported in a LIHEAP grant application.[111] It is logical that the HELP grant amount in the second year should be updated based on new heat costs reported in a LIHEAP application. In doing so, CAAs do not necessarily save time for those customers because the CAAs must revisit the file to make this particular update, regardless.

With the limitation in mind, Staff also believes this is an approach worth taking as it is consistent with the current practice in PacifiCorp's low income bill assistance program.[112] I recommend the Company works with CAAs closely to keep track of the number of customers on two-year certification track, evaluate the actual benefits, and modify the approach if necessary.

Q. What is your position on the change of income eligibility?

A. I support the proposal. Currently, the income eligibility ceiling for HELP benefits requires a rather complicated calculation. Schedule 129 tariff states, in part:

> For purposes of this Program, in areas where 50% of median income exceeds 150% of federal poverty guidelines, eligibility will be capped at 150% of federal poverty guidelines; and in areas where 50% of median income falls below 125% of federal poverty guidelines, eligibility will be capped at 125% of federal poverty

[111] Heat cost is usually calculated as the total energy cost minus the cost for base load. PSE HELP benefit applies to the energy cost after excluding heat cost because the heat cost is already reduced by LIHEAP grant.

[112] *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-111190, Order 07, 8-9, ¶¶17-18; (Mar. 30, 2012); *id.* at 18-19, ¶¶40-44.

> guidelines. To summarize, the income-eligibility ceiling for the Program fluctuates in a range between 125% and 150% of federal poverty guidelines; within the range, the precise figure equals to 50% of the median income of an area.[113]

Setting the income eligibility threshold at 150 percent of FPL will simplify the CAA's screening process. The proposal is consistent with the practice of federal LIHEAP and other utility-sponsored bill assistance programs. It is also consistent with the HELP benefits formula which is based on percent of FPL. It would not shrink the number of customers who would be eligible for PSE HELP benefits. To the contrary, in areas where 50 percent of the median income falls below 150 percent of FPL, more customers would become eligible for HELP benefits.

Q. Do you have additional recommendations for PSE's HELP program?

A. Yes, I have one more recommendation. I recommend that the Commission require the Company and its stakeholders to form a low income bill assistance advisory group, similar to the groups for Avista and Cascade. The advisory group can be tasked to meet regularly (no less than twice a year) to discuss ongoing issues and develop new ideas to improve the program. Based on my involvement with the low income advisory group meetings for Avista and Cascade, the platform provides stakeholders a collaborative environment to identify issues and seek solutions. Rather than litigating every low income issue in general rate cases, an advisory group like this can effectively resolve many issues related to the administration of the program, leaving large issues, such as program funding levels and big programmatic changes, for resolution in a general rate case.

[113] PSE Electric Tariff WN U-60, Schedule 129, Sheet No. 129-A.

Q. What guidance do you recommend the Commission give to the future advisory group?

A. I recommend that the Commission guide the future PSE low income bill assistance advisory group to adopt the four program goals initially adopted by the Avista low income advisory group and subsequently adopted by Cascade's advisory group. The goals have served very well to provide general guidance in the group's decision making. The four goals are:

1. Keep customers connected to their energy service;
2. Provide assistance to more customers than are currently served by the program;
3. Lower the energy burden of LIRAP participants; and
4. Ensure that LIRAP has the appropriate data to assess program effectiveness.

Q. Are there any agenda items that could be immediately addressed by the advisory group?

A. Yes. I can think of a few. For one, to my knowledge, the Energy Project is working with CAAs to launch an Internet-based portal to accept customer applications for energy assistance, either through a website or a mobile phone application. The project is still in the initial brainstorming stage. Collaboration from PSE and other stakeholders will be crucial to the success of this project. Right now, to receive energy assistance, low income customers need to take time to travel to a local CAA office to present income documentation in a one-hour long interview session. The available appointments are limited to CAA's staffing level and a long backlog can develop. Very few mail applications are accepted. An Internet-based application portal will greatly increase the outreach of the programs and spread the benefits to more eligible households. Staff supports the project, conceptually. But stakeholders will need to collaborate to work out important details and challenges, such as funding sources and administrative processes.

Moreover, the group could also take a more in-depth look at the data on energy burdens that CAAs have collected to help identify underserved customer segments. It could explore supplementary program designs such as arrearage management program or ways to assistance working poor customers. It could also look to jointly sponsor outreach activities to spread information to more households in need of assistance. Overall, I believe a collaborative advisory group will engage stakeholders to come up with innovative ideas to continuously improve the program independently of the timing of general rate case filings.

Q. Does this conclude your testimony?

A. Yes.