EXHIBIT NO. _____ (GCC-Testimony)
DOCKET NOS. UE920499, UE920433 and UE921262
WITNESS: GEORGE C. CARTER, III

BEFORE THE
WASHINGTON UTILITIES & TRANSPORTATION
COMMISSION

Complainant

v.

PUGET SOUND POWER & LIGHT COMPANY

Respondent

TESTIMONY
OF GEORGE C. CARTER, III

on behalf of
Skagit Whatcom Area Processors

February 1993

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
No. UE-920433; -920499; -921262 Ex. T-58 ✓

SKAGIT WHATCOM AREA PROCESSORS

DIRECT TESTIMONY OF GEORGE C. CARTER, III

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

A. My name is George C. Carter, III. I am employed by Utility Resources, Inc. (URI) as a vice president. URI is an economic consulting firm. We consult for various public and private clients, primarily in the energy and natural resource area. My business address is 1500 Liberty Street S.E., Suite 250, Salem, Oregon, 97302.

Q. What are your qualifications to give testimony in this proceeding?

A. My qualifications are included as Exhibit ____ (GCC-2).

Q. Have you testified before this commission in the past?

A. Yes I have testified before the Washington Utilities and Transportation Commission (WUTC) on several occasions in the past. My past testimony before the WUTC has addressed cost of service, rate spread, long run incremental cost and power cost normalization.

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

A. I was asked by the Skagit Whatcom Area Processors (SWAP), a group of frozen food and cold storage processors in Skagit and Whatcom counties, to review Puget's filed cost of service study, rate spread, and rate design in the rate design proceeding. Based upon my review, I was asked to submit testimony offering recommendations on rate spread and design.

Q. What conclusions have you reached in your review of Puget's rate spread, rate design and cost of service study?

A. Based upon my review of Puget's rate design and rate spread, I have concluded the following:

1. SWAP customers will pay parity ratios far in excess of other customers in the same service classes with Puget's proposed rates because they are included in rate classes where most other customers have very different usage characteristics than the SWAP customers;

2. Puget's demand and energy charges on Schedules 31 and 46 have too little differentiation between summer and winter seasons, given seasonal cost differences. This lack of seasonal differentiation is the primary cause of the higher parity ratios of SWAP customers;

3. Puget erroneously implements seasonal energy cost differentials in energy rates for all rate schedules (except the residential) because they use a percentage differential rather than an absolute differential. The net result is too small a difference between winter and summer rates for most schedules; and,

4. Puget's proposed revision to the penalty for poor power factor is not cost based. The proposed penalty spreads the cost for power factor correction inequitably. In addition, the proposed penalty will cause severe rate increases for certain customers, far in excess of class average increases.

Q. What have you concluded from your review of Puget's cost of service study?

A. Based on my review of Puget's cost of service study, I conclude the following:

1. Puget's allocation of energy related production cost ignores the seasonal differentials in energy related cost. As a result, summer use is allocated too much cost and winter use too little; and,

2. Puget's application of the peak credit method for classification of production cost errs by classifying too little expense to the demand component and too much to energy.

Q. What recommendations do you make?

A. I make the following recommendations:

1. Puget should create a new rate class for primary service and high voltage customers like SWAP customers whose usage tends to be summer peaking rather than winter peaking;

2. If Puget is unwilling to create new rate classes for summer peaking customers, Puget should allow those customers to switch to the irrigation rate schedules;

3. Puget should revise demand and energy charges on all rate schedules that are more reflective of seasonal differences in demand and energy costs;

4. Puget should develop a power factor penalty that is cost based; and

5. If the cost based power factor penalty cause severe rate increases for some customers, Puget should phase in the new penalty to reduce the adverse rate impacts.

RATE SPREAD AND RATE DESIGN

Q. Why do you conclude that SWAP customers will pay far higher parity ratios than other customers in similar service classes with Puget's proposed rate ~~spread~~ design? alh

A. Historically, SWAP customers taking primary service were placed in a group with other business customers that take service at primary voltage, Schedule 31. Currently, the difference in usage characteristics between SWAP customers and other Primary Voltage and High Voltage customers, along with the rate design that Puget proposes for these customers, causes SWAP customers to pay revenues resulting in far higher parity ratios than other Primary Voltage and High Voltage customers. In fact, SWAP customers on Schedule 31 will pay more than cost of service even though the class as a whole will pay much less than cost of service.

To charge rates that are absolutely fair to each and every customer, each customer would have to be charged a different rate because each customer has different usage characteristics. It would be very expensive to charge each customer a different rate, and the benefits of doing so would be far overshadowed by the cost of administering the multitude of rates. To reduce costs yet maintain a certain degree of fairness, customers are separated into groups that are charged common rates such that variation in usage characteristics within groups is less than the variation in usage characteristics between groups. This is reasonably fair if the usage characteristics of customers within each group are somewhat similar. If not, though, customers with significantly different usage characteristics within their group will either pay too high or too low rates. SWAP customers will pay rates that are too high.

Q. How are SWAP usage characteristics different than other Schedule 31 customers?

A. Most Schedule 31 customers have fairly flat usage throughout the year with slightly more usage in the winter than the summer. SWAP customers' usage is low in the winter and spring and peaks in the summer and fall. Exhibit ____ (GCC-3) shows the different usage patterns of the two groups. Page 1 of Exhibit ____ (GCC-3) shows monthly measured Kw demands as a percent of annual total measured monthly peak demands for SWAP and other Schedule 31 Customers. Page 2 of Exhibit ____ (GCC-3) shows monthly energy usage as a percentage of annual total energy usage for both groups. The exhibit clearly shows the dramatic differences in both demand and energy usage throughout the year between SWAP customers and other Schedule 31 customers.

Q. Does a similar pattern of differences in usage characteristics exist for Schedule 46 SWAP customers?

A. Absolutely. Exhibit ____ (GCC-4) shows the differences in usage characteristics between the SWAP customer on Schedule 46 and other Schedule 46 customers. The organization and interpretation of Exhibit ____ (GCC-4) is identical is Exhibit ____ (GCC-3). The same dramatic differences in usage characteristics are clearly evident.

Q. How do you know that this difference in usage patterns causes SWAP customers to pay too much?

A. With one exception, I have allocated Puget's cost of service not only to Primary Voltage and High Voltage customers as Puget does, but also to SWAP customers using Puget's cost of service methods. The single exception I make is to properly account for seasonal energy cost differences. I correct Puget's cost of service allocated to Primary Voltage and High Voltage customers for seasonal cost differences. I then further allocate this cost of service to SWAP customers using Puget's methods except for the correct seasonal energy cost differences. Generation and transmission demand costs are allocated on usage during the 200 highest load hours. Distribution demand costs are allocated on the 12 monthly non-coincidental demands, and customer costs are allocated on customer counts. This disaggregation of Primary Voltage and High Voltage cost of service to SWAP customers demonstrates that they will pay revenues that result in far higher parity ratios than other customers in the same service class under Puget's proposed rates.

Q. What are parity ratios, and why are they important?

A. Parity ratios are simply the ratio of proposed revenues for a rate class or group of customers to the cost of service for that same rate class or group. A parity ratio greater than one indicates that the group will pay more than cost of service. A ratio less than one indicates the group will pay less.

Parity ratios are an extremely important tool for rate spread and rate design analysis. They are used to set revenue targets for rate classes. Usually, target revenues are set to produce parity ratios close to one. However, if the parity ratio of a class is far from one, target revenues can be set to gradually move parity ratios to one over several rate changes to reduce the adverse impacts of dramatic rate increases. For example, Puget's Primary Voltage and High Voltage customers' parity ratios are 10% or more below one. Puget has set target parity ratios for these customers at levels less than one so that the customers move one-third of the way to full cost based rates, or a parity ratio of one.

Parity ratios can also be used to highlight inequities within a rate class. If a subgroup of customers has a parity ratio quite different than the class as a whole then it indicates that either the customer does not belong in the class or that individual components of rate design like demand, energy and customer charges are not in alignment with costs. This is the case for SWAP customers. There parity ratios are much higher than other customers in their service class.

Q. What is the problem with the higher parity ratios of SWAP customers?

A. It clearly shows that SWAP customers are being treated inequitably when compared to other customers taking similar service. It also is an indication that as Puget increases rates to move all Primary Service and High Voltage customers close to a parity of one, that SWAP customers' parity will be much higher than one unless Puget's aligns rate components more closely to cost of service.

Q. Can you illustrate the parity ratios that result from your more detailed allocation of cost of service to SWAP customers?

A. Yes. Exhibit ____ (GCC-5) shows the parity ratios that result from my detailed cost of service allocation to Primary Voltage SWAP customers. It shows the parity ratios that will result for these customers under Puget's proposed rates. It clearly demonstrates that SWAP customers' parity ratios are almost 9% more than the parity ratios of other Primary Voltage customers.

The testimony of Puget witness David Hoff shows that the current parity ratio of all Primary Voltage customers is .91. From Puget's Exhibit ____ (DWH-3), it can be determined that Puget's target parity ratio for all Primary Voltage customers is .94. SWAP Primary Voltage customers will pay parity ratios that are more than 10% greater than current parity ratios for Primary Service, 7.2% higher than target parity ratios for Primary Service, and almost 9% higher than other Primary Service customers under Puget's proposed rates.

Q. Does the parity ratio for the SWAP customer on Schedule 46 compared to the parity ratios of other High Voltage customers show similar discriminatory treatment?

A. Yes. The SWAP customer on Schedule 46 pays more demand costs than it causes. Exhibit ____ (GCC-6) shows a comparison of the parity ratios this Schedule 46 SWAP customer will pay with Puget's proposed rates compared to the parity ratio of other Puget High Voltage Customers. The parity ratio for the SWAP customer was derived by a more detailed cost of service allocation to this customer using the same methods described above for Primary Voltage customers. Puget's rates will produce a parity ratio for that customer of 96.7% of cost of service. Puget's rates will produce a parity ratio of only 87.4% for other high voltage customers. Puget's target parity ratio for High Voltage customers is 92%.

Q. What causes the disparity?

A. The disparity is caused primarily because Puget's demand costs For Primary Service and High Voltage Service do not contain enough seasonal differentiation, alh and to a lesser ~~lessor~~ extent, neither do Puget's energy charges. Puget's cost of service study and allocation of generation and transmission demand costs is based on class load during the 200 highest hourly loads. Calculations based on Puget response to SWAP data request 211 show that 42.5% of those loads occur in December, 34.5% in January and 18% in February. Of the remaining 5% of the 200 highest loads, 4% occur in March and 1% in November. These 200 hourly loads are responsible for all of Puget's generation and transmission demand costs.

Despite the fact that 95% of these loads, and therefore 95% of the causation of generation and transmission demand costs, occur in the three month period from December through February, Puget's proposed rates recover these costs throughout the year. SWAP customers' loads are much lower than their average alh during the months when generation and transmission demand costs are highest, yet they end up being charged for these costs throughout the year. They end up paying for generation and transmission demand costs that were caused by <u>other</u> customers' loads because their load characteristics are different and because Puget's proposed rates do not match cost causation closely enough. In fact, a similar problem exists with all of Puget's rate schedules with demand charges because none of Puget's rate schedules with demand charges (with the exception of Schedule 35) has enough differentiation between winter and summer rates to properly reflect the generation and transmission demand costs that all are caused by winter loads.

Q. Does the lack of sufficient seasonal differentiation in energy costs contribute to the discriminatory treatment of SWAP customers as well?

A. Yes, although not to as great an extent. Puget's energy costs are 6 mills higher in the winter when the SWAP customers' loads are lowest. However, Puget only has a 3.387 mill difference between winter and summer rates on Schedule 31 and a 2.999 mill difference on Schedule 46. Consequently, SWAP customers end up paying higher costs in summer than they should. These customers subsidize lower winter rates that benefit other customers whose use is higher in winter.

Q. Does the lack of sufficient seasonal differentiation in energy charges affect customers other than SWAP customers?

A. Absolutely, because Puget incorrectly implemented its estimated differences in seasonal energy costs. All customers with relatively more usage in summer pay higher rates than they should because there is insufficient seasonal differentiation in energy rates.

Q. How did Puget implement seasonal energy cost differences in rates?

A. Using the latest estimates of seasonal differentiated avoided costs and the residential water heating load shape, Puget estimated the seasonal differentials in energy costs. This is shown in Puget response to Bench Request No. 5. That response shows winter costs of 63.246 mills/kwh and summer costs of 56.354 mills/kwh. Winter costs are 6.9 mills (12.2%) higher.

To determine seasonal differences in energy rates for the proposed rates, Puget estimated that there was an <u>approximate</u> 10% difference in rates. They applied this 10% factor to all schedules with seasonal rates. Unfortunately, this only works for schedules with energy rates approximately equal to the avoided costs discussed above, or the residential rates. When the 10% factor is applied to a class with only 30 mill rates, the seasonal differential will only be 3 mills, not the correct 6 mills. Since seasonal differences in energy costs result from differences in variable costs, the differential will not vary with the absolute level of rates. Therefore, it is correct to apply an absolute differential to all rate schedules, not a relative, or percentage differential. Using a relative differential understates the differences in energy costs for rate schedules with relatively lower energy costs.

Q. What should the energy rates be on Schedule 31?

A. Using Puget's total revenues to be recovered in energy charges on Schedule 31, the winter and summer energy billing determinants and the proper 6 mill differential between summer and winter, the proper winter energy rate for Schedule 31 is $0.038554 per Kwh, and the proper summer rate is $0.032554 per Kwh. These energy rates should replace Puget's proposed energy rates for Schedule 31.

Q. What should the energy rates be on Schedule 46?

A. Again using Puget's proposed energy revenues, billing determinants, and the proper 6 mill differential, the correct winter rate for Schedule 46 is $0.34569 per

Kwh and the correct summer rate is $0.028569 per Kwh. These rates should replace Puget's proposed rates.

Q. What should the correct seasonally differentiated demand charges be on Schedules 31 and 46?

A. The cost of service study ~~indicates~~ indicate that the generation and transmission demand costs are approximately $5.65 per Kw billed during the 6 month winter period. The generation and transmission demand cost should be recovered during winter because it is caused by Puget's 200 highest loads, which all occur in the winter. In fact, 95% of these loads occur in the 3 month period from December through February. 99% occur in the 4 month period from December through March. Applying the $5.65 differential to proposed demand revenues and billing determinants for Schedule 31 produces a winter demand rate of $8.05 per Kw and a summer rate of $2.40 per Kw. These rates should replace Puget's proposed rates to more appropriately reflect seasonal differences in demand costs.

Q. What are the proper winter and summer demand charges for Schedule 46?

A. Almost 90% of the demand costs for Schedule 46 are generation and transmission related. Therefore, most of the proposed demand revenues should be recovered in winter because that is when they are caused. On that basis and applying the credit for interruptible service also to winter, the winter demand charge for Schedule 46 should be ~~$3.12~~ $3.57 per Kw. The summer demand charge should be ~~$0.89~~ $0.47 per Kw.

Q. If Puget implements the correct demand and energy charges on Schedules 31 and 46, is there any need to develop separate rate schedule for SWAP type customers?

A. Not necessarily. If Puget's rate schedules properly reflected cost of service differences, each customer would pay close to its cost of service even if its usage characteristics were different from that of the class as a whole.

Q. Are there other reasons why Puget's proposed rates should be revised to reflect cost of service?

A. Yes. Cost of service based rates provide customers with proper price signals. Correct price signals cause customers to make consumption and investment decisions that promote the best use of society's scarce resources.

In addition, in the case of SWAP customers, a rate schedule that properly reflects cost of service is a necessity if these customers are to stay on Puget's system. These customers must remain competitive with other food processors in Washington. Puget's existing and proposed rate place these customers at a competitive disadvantage compared to other food processors in Washington. Failing to give Puget's SWAP customers the benefits of their relatively lower cost of service due to seasonal usage patterns, either through new rate schedules or modification of existing rate schedules to properly reflect cost of service, threatens their economic viability.

Q. How do you know that Puget's existing and proposed rates place SWAP customers at a competitive disadvantage?

A. Exhibit ____ (GCC-7) shows the annual power bills for a typical SWAP customer using Puget's existing rates, Puget's proposed rates, Seattle City Light rates, and Grant County PUD rates. It is quite clear that both Puget's existing and proposed rates are considerably higher than the rates that would be paid at Seattle City Light or Grant County PUD. My understanding is that electric costs are second only to labor in the operating cost of cold storage and frozen food processors. The only way a frozen food processor or cold storage operator served by Puget could compete with a food processor served by Seattle City Light or Grant County PUD would be to somehow lower costs in other portions of its operations.

Q. Why did you choose Grant County PUD and Seattle City Light for comparison?

A. I understand that four food processors that had operations in Skagit and Whatcom counties (Stokley Van Camp, Libby McNeil Libby, Cedergreen Frozen Foods and Simplot) have moved their operations to Grant County because of lower power rates. I have been informed that National Frozen Foods is seriously considering expanding its operations at its Moses Lake plant in Grant County, but would not consider expanding operations in Skagit County.

I have chosen Seattle City Light's rates to provide a comparison with operators in western Washington. SWAP customers also face competition from seafood processors located in Seattle City Light's territory who have similar operating costs, except for electric power.

Q. In conclusion, how do you recommend that Puget properly reflect cost of service to SWAP customers and others with similar usage characteristics?

A. I recommend that separate primary voltage and high voltage rate schedules be implemented for food processing customers and other Puget customers with loads that tend to peak during the summer season. This would be the easiest way to give these types of customers the benefits of their reduced cost of service, yet maintain reduced risk of revenue instability.

Q. If Puget will not or cannot implement new rate schedules for this type of load, what do you recommend?

A. Allow these types of customers to take service on the existing irrigation rate schedules. The pattern of loads of these customers more closely matches the pattern of loads of irrigation customers than it does the other Schedule 31 customers.

Q. If it would be impossible to allow these customer to take service on the irrigation rate schedules, what do you recommend?

A. I recommend that Puget's rates properly reflect the cost of service differences in demand and energy charges discussed above. If Puget does not do anything to accommodate the reduced cost of service and the competitive disadvantages faced by these customers, Puget risks forcing them to close or curtail operations. This will harm the economies of Skagit and Whatcom counties and reduce revenues to Puget. Future rate increases to Puget's remaining customers will be necessary to replace the contribution to fixed costs resulting from revenues from current SWAP. It is in everyone's best interest to keep customers like SWAP on the system to use resources that would otherwise be idle in the off peak summer months.

POWER FACTOR PENALTIES

Q. Why do you conclude that Puget's proposed penalty for low power factor is not cost based?

A. Puget's proposed power factor penalty is not based on the least cost of correcting low power factor problems. Puget's power factor penalty is based on the assumption that poor power factor can only be corrected by installing additional generation, transmission and distribution facilities to serve the reactive power requirements caused by customers with low power factor. However, for large reactive power requirements, it is much cheaper for Puget to install capacitors to improve power factor than to install additional generators, transmission lines and distribution equipment and lines.

This is clear in Puget's response to WICFUR data request Number 319, which is included as my Exhibit ____ (GCC-8). That response shows that on average, the cost of Puget's proposed method to correct for poor power factor, which is based on the cost of generation, transmission and distribution facilities, is approximately equal to the cost to install capacitors to correct the problem. However, for the customer classes with larger demands and larger reactive power requirements per customer, the cost of installing capacitors to reduce reactive power requirements is much less than the cost of generation, transmission and distribution facilities to serve reactive power requirements.

Q. Can you explain how the response to WICFUR 319 shows this?

A. Yes. The table in WICFUR 319 shows a comparison by rate class of the additional charges to customers with poor power factors with Puget's proposed penalty and the cost to Puget to install capacitors to correct for poor power factors. The column in the response labeled "Customer Cost" shows additional charges to customers based on increasing measured demand for power factor pursuant to Puget's proposed penalty, and the column labeled "Puget Power Cost" shows the cost to Puget to correct the problem. The top line in the table shows that in total, the costs of correction are approximately equal to the additional charges to customers. However, examination of the figures for each rate class shows that for all classes with an average capacitor size greater than the average, the increased charges to the customer are greater than Puget's cost to correct poor power factor. For Schedule 31, the increased charges to the customer are 3.25 times higher than Puget's cost to fix the problem. Alternatively, for all classes with less than average capacitor size, the increased charges are less than Puget's cost to correct. The problem results from economies of scale in capacitor engineering and installation, which Puget's proposed penalty ignores. Exhibit ____ (GCC-9) shows the average annual cost per KVar of capacitor size for the average capacitor size for each rate class based on the costs in WICFUR 319. It clearly shows the economies of scale issue.

Q. What does the line labeled "Puget Penalty" in Exhibit ____ (GCC-9) represent?

A. It represents the penalty Puget's proposed power factor penalty would impose upon a Schedule 31 customer divided by the KVar capacitor size that a customer with an 80% power factor would have to install to correct his power factor to 95%. It, therefore, represents Puget's penalty per KVar of capacitor size to a customer that does not correct its power factor and pays Puget's penalty.

Q. Why have you included that line in Exhibit ____ (GCC-9)?

A. I have included it for two reasons. First, it clearly demonstrates that Puget's proposed penalty is far in excess of cost for all Schedule 31 customers with power factor problems, except for the very smallest customers. Second, it demonstrates the problems that Puget's penalty might cause. Assuming that a customer could install a capacitor for approximately the same cost as Puget, it is cheaper for a customer not to correct its power factor when the Puget penalty line is below the capacitor cost line. When the Puget penalty line is above the capacitor cost line, it is cheaper for the customer to install a capacitor to correct its power factor. Since the Puget penalty line is above the capacitor cost line for all but the very smallest capacitors, most customers will find it cheaper to correct their power factor than pay Puget's penalties. Puget revenue forecasts include increases of approximately 14% in billed demand for Schedule 31 customers with poor power factors. If many of these customers correct their power factors, Puget risks up to a 14% demand revenue shortfall for Schedule 31 customers.

Q. How does the proposed power factor problem affect SWAP customers?

A. Puget's proposed power factor penalty will cause an increase of over 1200% in power factor penalties for SWAP customers on Schedule 31. In fact, the increase in power factor penalties causes 30% of the increase in rates for SWAP customers.

Q. What do you recommend power factor penalties be?

A. Puget's existing power factor penalty is probably not appropriate for all rate classes, but neither is their proposed alternative. The best solution would be to develop a different power factor penalty for each rate class that is cost based and that recognizes the economies of scale in power factor correction.

Q. How can this be done?

A. A KVarh charge should be calculated for each rate schedule based on the average size and power factor for customers with poor power factors. Consider a Schedule 31 customer with a peak demand of ~~2000~~ 1,000 Kw with an average power factor of .86. An approximate 265 KVar capacitor would be necessary to correct alh the power factor of this customer to .95. This is approximately equal to the 277 average size capacitor for Schedule 31 shown in response to WICFUR 319. At an average annual cost per KVar of $3.93, also from response to WICFUR 319, the total annual cost to correct the power factor to .95 would be $1,041. Puget's proposed penalty would cause this customer to pay an additional ~~$14,682~~ $6,530 alh annually. Assuming an average load factor of 55%, this customer would consume 4,818,000 Kwh. If the customer did not correct its power factor, its annual reactive power use would be 2,858,833 Kvarhs. Its annual cost to correct for poor power factor per KVarh would be .0364 cents per KVarh. This is the appropriate cost based power factor penalty for Schedule 31.

Q. What would Puget's proposed penalty be for this customer?

A. If this customer did not correct its power factor, Puget's proposed penalty would adjust this customers' billed demand upwards by approximately 104.65 KVa per month. That increase in billed demand would require the customer to pay additional revenues of $6,530 annually. This amount is 6.3 times more than the annual cost of $1,041 to install a capacitor to correct the power factor.

Q. Do you recommend that the KVarh charge for Schedule 31 be changed to this amount?

A. Yes. In addition, an analysis similar to that discussed above should be done for all rate classes. The KVarh charge for other classes may have to be changed.

COST OF SERVICE STUDY

Q. Why do you conclude that Puget's cost of service study ignores seasonal energy cost differences?

A. During the deposition of Mr. Hoff, he was asked several question about seasonal energy cost differences. Mr. Hoff referred to responses to WICFUR data requests 310 and 312 as supporting seasonal energy cost differences (Deposition pp. 42-50). Puget's response to WICFUR 312 indicates that power supply information shows approximately a 6 mill/kwh difference between summer and winter. Puget's response to WICFUR 310 is an avoided cost study that also supports seasonal cost differences in the 6 mill range. Mr. Hoff, Puget's rate design witness, agrees with these seasonal differences and attempts to incorporate them into rates.

Despite Puget's acceptance of these seasonal cost differences, Puget ignores them in the cost of service study. The cost of service study allocates annual energy cost using annual usage. There is no recognition of the fact that per unit winter costs are higher than summer costs. Consequently, rate classes that use relatively less energy than average in winter and more in summer are allocated too much energy cost and remaining classes are allocated too little.

Q. How could Puget correct the problem?

A. Puget could correct the problem quite simply by incorporating either of two changes to the cost of service study. Puget could separate annual energy costs into winter and summer components and allocate winter costs using only winter usage and summer costs using only summer usage. Alternatively, Puget could develop a weighted energy allocator weighting winter use by an estimate of winter incremental power costs and summer use by an estimate of summer incremental power costs. Of course, the winter weight would be approximately 6 mills/kwh higher than the summer weight. Annual energy costs could then be allocated using the weighted allocator.

Q. Has Puget made any other errors in the cost of service study?

A. Yes. They incorrectly applied the peak credit method to classify production costs and generation related transmission costs.

Q. What errors were made in Puget's application of the peak credit method for classifying production cost?

A. Puget made two basic errors in application of the peak credit method. First, Puget's cost of service study only credits one-half the capital and fixed O&M expense of the peaking plant to the baseload plant. Second, it assumes an excessive plant factor for the baseload plant. Correcting these two errors changes the capacity/energy split from Puget's incorrect ratio of ~~17/83~~ 16/84 to ~~30/70~~ 29/71. A ~~30/70~~ 29/71 capacity/energy split should be used in the cost of service study. alh alh

Q. Why does Puget use only one-half the capital and fixed O&M expense of the peaking plant in the peak credit?

A. Mr. Hoff says in his rate design testimony that a combustion turbine has more uses than simply providing power during the highest load hours; for example, backing up poor performance of other resources, assisting during transmission outages, making off system sales and assistance for seasonal exchanges (Hoff Rate Design testimony, page 11). Because of these uses, Mr. Hoff concludes that the full fixed cost of a combustion turbine overstates its value as a peaking resource, and he chooses to credit only one half of the fixed cost.

Mr. Hoff ignores the cause for acquisition of the peaking capacity. Peaking capacity is purchased to maintain an adequate safety margin over loads. Once it is purchased and available it may have multiple uses, but it was acquired to maintain the margin. Were the margin adequate, the additional peaking capacity would not be purchased, even with the other uses. The cost of the peaking plant is caused by the lack of margin, and not by the other uses of the plant. In addition, the other uses cited by Mr. Hoff are reasons why a reserve margin is necessary and so are not really any different than peaking requirements.

Q. Why does Puget use an excessive plant factor for the baseload resource?

A. They mistakenly use the availability factor rather than the expected capacity factor. Doing so misrepresents the cost of energy generated from the plant, and the true marginal cost of energy.

If marginal costs are to have any meaning, they must represent real costs that consumers will experience. If Puget estimates marginal cost of a combined cycle plant assuming that it will generate up to its availability rate, when in fact it will not, it understates the actual per unit cost of that plant to consumers. It is difficult to imagine that a combined cycle plant would operate at the full availability rate of 80% when Puget's system load factor is only approximately 60% and Puget's coal plants and much of its hydro capability would be dispatched prior to a combined cycle plant.

Q. What recommendations do you make regarding Puget's cost of service study?

A. I make the following recommendations:

1. I recommend that the allocation of energy costs in Puget's cost of service model be corrected to account for the seasonal differences in energy costs.

Correction should account for the 6 mill difference between winter and summer costs; and,

2. I recommend that Puget properly apply the peak credit to classify production and generation related transmission costs in the cost of service study. When the peak credit method is applied correctly, ~~30%~~ 29% of production and generation related transmission costs should be and ~~70%~~ 71% to energy. alh

Q. Does this conclude your testimony?

A. Yes.