SERVICE DATE 147

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BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

PETITION OF PUGET SOUND POWER & LIGHT COMPANY FOR AN ORDER REGARDING THE ACCOUNTING TREATMENT OF RESIDENTIAL EXCHANGE BENEFITS	DOCKET NO. UE-920433
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PUGET SOUND POWER & LIGHT COMPANY, Respondent.	DOCKET NO. UE-920499
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PUGET SOUND POWER & LIGHT COMPANY, Respondent.	DOCKET NO. UE-921262 NINTH SUPPLEMENTAL ORDER ON RATE DESIGN ISSUES

PROCEEDINGS: On April 30, 1992, Puget Sound Power & Light Company (Puget or company) filed proposed changes to its currently effective Tariff No. WN U-60, Tariff G. The changes were intended to revise rate spread and rate design aspects of those tariffs.

HEARINGS: The Commission held hearings on June 19, September 23 and 24, 1992; May 10 and 11, June 21, 23 and 24, 1993. The hearings were held before Chairman Sharon L. Nelson, Commissioner Richard D. Casad, Commissioner A.J. Pardini, Commissioner Richard Hemstad and Administrative Law Judge Alice L. Haenle of the Office of Administrative Hearings. The Commission gave proper notice to all interested parties.

PARTIES: The following parties appeared in the rate design portions of these hearings. Respondent Puget was represented by James M. Van Nostrand, attorney, Bellevue. The Commission was represented by Donald T. Trotter, assistant attorney general, Olympia. Charles F. Adams and William Garling, assistant attorneys general, Seattle, appeared as Public Counsel. Intervenor Washington Industrial Committee for Fair Utility Rates (WICFUR) was represented by Mark P. Trinchero, attorney, Portland, Oregon, and Peter J. Richardson, attorney, Boise, Idaho. Intervenor Skagit Whatcom Area Processors (SWAP)[1] was represented by Carol S. Arnold, attorney, Seattle. Intervenor Department of Defense, on behalf of the consumer interests of the Federal Executive Agencies of the United States (FEA), was represented by Norman J. Furuta and Jose Aguirre, attorneys, San Bruno, California. Intervenor Building Owners & Managers Association of Seattle and King County (BOMA) was represented by Daniel Compton and John Cameron, attorneys, Portland, Oregon.

SUMMARY

The Commission accepts the company's Peak Credit cost-of-service study, with modifications, and makes other determinations about contested cost-of-service issues. The Commission determines that PRAM 3 resource cost recovery should be spread based on the Peak Credit factors adopted in this order. The Commission reserves all other rate spread decisions until the amount of the revenue deficiency to be spread, if any, is determined in the general rate case. The Commission resolves contested rate design issues. In making its determinations, the Commission refers a number of parties' proposals to collaborative processes for further study.

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[1] SWAP companies in this case are Bellingham Cold Storage Company, Trident Seafoods, Versacold, Americold, National Frozen Foods, and Bellingham Frozen Foods.

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I. PROCEDURAL HISTORY

In Docket Nos. UE-901183-T and UE-901184-P, the Commission established on an experimental basis the company's periodic rate adjustment mechanism (PRAM). As part of its Third Supplemental Order, the Commission instructed the company to make a rate design filing by April 1992. This case was filed in response to those instructions.

The company originally filed this case on April 30, 1992, under Docket No. UE-920499. That filing used the test year from the company's last general rate case, the twelve months ended September 30, 1988.[2] The company presented its direct case in hearings on September 23 and 24, 1992.

Subsequently, the company on October 30, 1992, filed a general rate increase request under Docket No. UE-921262. That filing used as a test period the twelve months ended June 30, 1992.

The Commission by its Order issued November 25, 1992, consolidated this rate design filing (UE-920499), the general rate increase filing (UE-921262), and an accounting petition regarding treatment of Bonneville exchange benefits (UE-920433). The Commission set a separate hearing schedule for rate design issues, to ensure full review. The company waived the suspension date on the rate design filing until October 1, 1993.

Additional hearings were held on rate design issues on May 10 and 11, 1993. The Commission heard public comment on both rate design and general rate filing issues on June 21, 23 and 24, 1993. The parties submitted briefs on rate design issues on July 9, 1993.

II. SCOPE OF THIS ORDER

This order will decide cost of service, rate design, and some rate spread issues. Revenue requirement issues will be addressed in a separate, subsequent order. Actual rate spread, and the retail rates Puget may charge, will be determined after the revenue requirement is established.

The Commission has adopted a number of procedures designed to encourage the company to acquire resources that minimize costs in the long run. The Commission's intent in requiring the company to make this rate design filing was to

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[2] The last general rate case was Docket No. U-89-2688-T. The Commission's Third Supplemental Order was issued January 17, 1990.

ensure that the structure and level of Puget's rates were consistent with the purposes of least-cost planning, and the proposition that efficient use of energy will tend to minimize the long-term cost of meeting all energy needs.

The Commission urged parties to work together to address all concerns and to ensure adequate information would be presented to the Commission. It noted that the parties agreed that appropriate price signals must be provided to customers, and instructed the company to provide information that would enable a determination of base and resource costs for each class.[3]

After the Commission consolidated the company's rate design filing and general rate increase filing, the company requested that the Commission issue its decision on rate design in this proceeding ahead of the revenue requirement decision. Thus, the Commission is issuing this order now, even though the remainder of the proceeding will not conclude until the end of September. The company intends to use the time between issuance of this order and the final order to make changes to tariff schedules, so that new rates can go into effect by October 1, 1993.

The parties have asked that this order resolve the following issues: the appropriate type and use of a class cost of service study; the concept to be used in spreading any increased revenue requirement, if necessary; and all issues specific to individual schedules. The Commission will address the cost-of-service study, individual schedules, and miscellaneous rate design issues in this order. We will reserve our decision on rate spread to our decision on the general rate increase filing, in order to consider the total amount of increase to be spread, if necessary.

III. COST-OF-SERVICE ISSUES

A. History

The purpose of conducting a cost study is to determine the contribution each class makes to the company's overall revenue requirement, based on an analysis of how utility system costs are caused. The Commission then uses the results of this study as one tool for deciding "rate spread," or how much of an approved revenue increase should be recovered from each class. As noted earlier, the Commission will reserve its discussion of the use to be made of the cost study results and rate spread for the order resolving the general rate increase request.

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[3] Docket Nos. UE-901183-T and UE-901184-P, Third Supplemental Order.

The Commission has in the past stated its interest in having available a variety of approaches to cost of service, in order to compare the results of different study methodologies. The Commission in past decisions relating to cost of service has rejected marginal cost for use in developing rate structures (Cause U-78-05). Later, in its Order in Cause U-82-10/11, the Commission noted that embedded cost-of-service studies could be "forward looking" if the current relationship between peaking and baseload resource costs were used to classify generation costs. We note here that marginal cost signals may be implemented through rate design, even in the absence of a marginal cost study. The Commission also has rejected (most recently in Cause No. U-89-2688-T and U-89-2955-T) the use of a "minimum system" approach for classifying distribution costs.

B. <u>Is the company's Peak Credit embedded cost method reasonable?</u>

Yes. The company has put forward the only cost study method proposed in this case, a Peak Credit approach that allocates the company's embedded costs. Its Peak Credit method includes a "forward-looking" dimension in that it takes the cost of a current peaking resource and compares it to the cost of current baseload resources. The resulting ratio (or "peak credit") is then used to classify total company resource-related embedded costs as serving either "demand" or "energy" needs.[4]

All parties, with the exception of the FEA, accepted this Peak Credit approach as valid and reasonable. The FEA objected to the company's approach because it excludes actual engineering considerations and ignores the company's specific resource mix and load factor. FEA argued that the Commission should convene another proceeding to resolve problems with the company's method. Absent another proceeding, FEA recommended that the Commission simply follow existing class revenue relationships in spreading any revenue increases approved as part of this consolidated proceeding.

The Commission accepts the Peak Credit cost-of-service method put forward for analyzing class costs in this case. We find that it is reasonable to shape the allocation of embedded

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[4] "Demand-related costs vary with the kilowatt (kW) demand imposed by the customer. "Energy-related" costs vary with the energy or kilowatt-hours (kWh) that the utility provides.

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costs according to current demand/energy relationships. We gave substantial weight to the fact that participants in the Rate Design Collaborative reached consensus on this approach.[5]

We commend the parties who participated in the Rate Design Collaborative, as well as the company and its Rate Design Task Force, for their work in coming to consensus on a cost study approach. For those parties who participated in it, the Collaborative appears to have successfully narrowed the contested issues in this proceeding, allowing for a better focus of those remaining. However, SWAP and FEA, which are parties to these consolidated cases, did not participate in the Collaborative's discussions. We direct the company to include FEA and SWAP in future collaborative efforts, and to make a good-faith effort to determine when other entities should be represented.

Elsewhere in this order, we identify other areas where we believe further collaborative efforts could be fruitful. We expect a broad range of parties to be invited to participate in such efforts. The Commission does not expect that all of the issues forwarded to the collaborative will, necessarily, be resolved. Nor do we pre-judge how we will evaluate the resulting proposals. We are hopeful that, as occurred in this proceeding, the process will identify areas where consensus can be reached, and assist by providing common understanding of positions and alternatives on issues that are contested.

C. <u>How should costs be classified within the Peak Credit method?</u>

While parties other than FEA accepted the company's basic Peak Credit method, there were disputes about specific elements of the study.

1. Classifying generating costs.

The company classified generation costs as 16 percent peak and 84 percent energy-related, using the ratio of the current cost of a peaking resource (a simple cycle combustion turbine (CT)) to the current cost of a baseload resource (a combined cycle combustion turbine (CCCT)) to derive the percentage of all resource costs that should be classified as peak related. The company considered only one-half the fixed costs of a CT because CT units provide other benefits in addition

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[5] The Commission does not, however, accept the Company's invitation to designate Puget's model to be used as the standard in future proceedings. As circumstances change, and theories evolve, other approaches to cost of service analysis may prove to be relevant.

to peaking. The company used fuel oil as the fuel choice, based on its expectation that lower-cost natural gas would not be available at times of extreme peak. The company also adjusted the CCCT cost by the facility's capacity factor (80 percent), which is also used in the company's planning and avoided cost calculations.

Commission Staff and Public Counsel agreed with the company's calculations, but recommended that natural gas represent some portion of the fuel cost. Public Counsel said the company should assume a "typical" year in which a portion of the fuel used would be gas (150 of 200 hours). Commission Staff argued that tension between the "forward looking" planning assumptions and the embedded cost elements of the company's approach should be resolved in favor of actual test year embedded costs in which gas was burned for all peak hours.

WICFUR and other intervenors accepted the company's use of oil, but recommended that 100 percent of the CT costs should be used, and that annual utilization of the CCCT at 54 percent should be used instead of the company's proposed capacity factor. FEA argued that the Peak Credit method was invalid on its face. However, on brief, FEA said that peak costs should be set on the basis of usage at a "break even" point between peak and baseload plant investment. FEA also offered a number of other alternatives it believed would make the company method more "cost-based."

The Commission finds it reasonable to adjust one element of the company's proposed cost split between peak and energy. With respect to the calculation of CT costs, we agree that it is reasonable to look at how the system and the facilities will be used. Thus, we accept the company's use of half the fixed costs of the combustion turbine as properly reflecting the fact that CTs provide benefits in addition to peaking capacity. Similarly, we agree with the position of Public Counsel that the calculation of CT costs should reflect in part the cost of natural gas, which is the only fuel the company used in the test year, and which we expect that it will use, in part, in most years. We also accept as reasonable the company's use of an 80 percent capacity factor in calculating the cost of a CCCT, based on the company's consistent use of this factor in its resource planning and avoided cost calculations. The result of this adjustment is a classification of generating costs as 13 percent peak and 87 percent energy-related.

2. Classifying transmission-related costs.

The company proposed to split transmission costs as having two different functions -- generation-related transmission and distribution-related transmission. The company stated that generation-related transmission consisted of long-distance facilities needed to bring resources from distant power plants into the company's service territory, while distribution-related transmission investment is generally assumed to be driven by increments in system peak load.

The company proposed to classify generation-related transmission in a manner consistent with that used for other generating facilities, using the Peak Credit ratio. The company would classify the remaining transmission as a demand-related cost, consistent with the primary design consideration.

Commission Staff recommended that all transmission costs be classified using the Peak Credit ratio. Commission Staff pointed out that transmission costs are not solely a function of peak, but are incurred to meet both on- and off-peak needs. Commission Staff cited the Commission's historical rejection of proposals to classify a portion of transmission costs as 100 percent demand-related. Public Counsel agreed with Commission Staff, citing in support the year-round use of transmission facilities, the need to include off-peak classes as benefitting from transmission investment, and economies of scale in designing the system.

WICFUR, SWAP, and BOMA supported the company's proposed split. FEA argued that 100 percent of all transmission costs should be treated as demand-related.

The Commission again rejects the company's proposal to split transmission-related costs and to classify a portion as 100 percent demand-related. Public Counsel argues persuasively that many considerations other than peak demand influence the design and cost of the transmission system. Commission Staff's position conforms with our continuing belief that "distribution-related" transmission lines are constructed to deliver energy as well as to meet peak demand. Thus, we reaffirm that transmission network costs should be classified as partly driven by demand and partly by energy, using the approved Peak Credit ratio. We are interested, however, in Public Counsel's suggestion that a more accurate assignment of transmission costs might be achieved through a more detailed analysis of the actual engineering and use of the company's transmission system and suggest further study.

3. **Classifying distribution-related costs.**

The company proposed to classify distribution costs using the Basic Customer method, which treats substations, poles, towers, fixtures, conduit, and transformers as demand-related. Service drops and meters are classified as customer-related. The company put forward this method in lieu of the Minimum System approach it prefers, primarily in the interest of promoting consensus, and because it is compatible with the use of a decoupling mechanism.

Commission Staff and Public Counsel strongly supported the use of the Basic Customer method as an appropriate allocation. Public Counsel recommended that the Commission also consider approving a method similar to that applied in Cause No. U-86-100, whereby distribution costs were considered to have energy-, demand- and customer-related aspects.

WICFUR and SWAP recommended use of the Minimum System approach. This would classify most distribution-related costs according to the relative number of customers in a class. WICFUR argued that this method better reflects the fact that a multitude of small customers requires a more extensive distribution system as compared to large customers with the same total energy requirements. Intervenor BOMA contended that the Basic Customer classification for distribution costs deviates from standard regulatory practice, and pointed out that other generally accepted methods would show commercial customers in a more favorable light in terms of the class' revenue-to-cost ratio.

The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals.

4. **Demand or peak allocation factors.**

In order to develop ratios for allocating those costs that have been classified as "demand-related," the company proposed to use the top 200 hours of the test year, consistent with the design of system peak facilities. Both Commission Staff and Public Counsel supported the company position.

WICFUR alleged that the top 200 hours did not represent the expected winter peak and understated the company's true peak demand. WICFUR stated that its proposed method more closely approximates the short, sharp system peak the company uses to plan new capacity. WICFUR proposed to calculate peak allocation factors using test year days within 95 percent of the test year system peak day. WICFUR would also adjust the peak and non-coincident peak allocators to account for peak temperature differences between the test year and the coldest year (1990).

FEA proposed that the company use the highest 400 hours, based upon the fact that, for up to 400 hours of production, use of a peaking resource is most cost-effective. For production beyond that amount, it is more cost-effective to invest in additional base load resources.

The Commission accepts the company's proposal. Generally, the proper period over which to allocate the demand-related costs of peaking resources is the hours when they are expected to be used. The 200 hour proposal by the company is reasonably representative of the system peak and the actual resources put into place to serve that peak.

5. Energy allocation factors.

In order to develop ratios for allocating energy-related costs, the company proposed to use annual usage for the test year. WICFUR argued that the company should be required to adjust annual and peak test year usage to normal (in this case, colder) temperatures and to adjust each class' consumption to include peak kiloWatt hours (kWhs) and annual kWhs saved through conservation. WICFUR alleged that this approach is necessary in order to treat saved kWhs (conservation) as a resource just as generated kWhs are a resource. Commission Staff rejected the proposition that adjusting the class energy allocation factor in this manner is necessary to treat conservation resources the same as supply-side resources. Public Counsel supported the company's claim that more information about factors affecting actual savings ("free riders", load retention, etc.) would have to be developed before peak or energy allocators could be adjusted for class conservation savings.

Intervenor SWAP claimed that the proposed energy allocation factors over-allocate costs to customers whose annual energy consumption is concentrated in the summer. SWAP recommended that the company be required to develop energy allocators that reflect actual seasonal cost differentials.

On rebuttal, the company accepted WICFUR's proposed temperature normalization adjustment for the residential class energy allocator only. The company rejected other proposed adjustments. Seasonal cost determination is not the goal of a cost study, according to the company. In any case, the company said it lacked essential data to make a seasonal adjustment or any of the other adjustments recommended, although the company stated that some, like the conservation adjustment, might be reasonable. The company proposed to investigate issues affecting the class allocation factors raised in this proceeding for presentation in its next general rate increase filing.

The Commission accepts the company's rebuttal position. Although certain potentially significant issues surfaced, no parties made a compelling case that allocations could be made more accurate with existing data. The Commission accepts the company's offer to investigate these issues and recommends that the results of this study and any recommended solution be evaluated in a collaborative setting. In particular, the Commission asks the parties to consider weather normalization for all weather-sensitive classes. We are also persuaded by SWAP's presentations that more work must be done in order to ensure that seasonal cost differentials are properly represented in the company's cost analysis. We ask that this effort begin immediately.

IV. <u>PRAM ISSUES</u>

This proceeding represents a consolidation of several filings, including the general rate increase filing.[6] The company's PRAM 3 rates will be implemented at the same time as rates approved in this proceeding. Both the company and Public Counsel have proposed to update the spread of PRAM rate changes by using the Peak Credit results from this proceeding to allocate resource cost changes in the PRAM. FEA rejects the company's proposed change and supports the existing demand/energy split.

The Commission approves the PRAM resource cost recovery rate spread based on the Peak Credit factors adopted in this order. Since we have found the Peak Credit method to be an appropriate means to assign costs to classes, it is reasonable to use it to assign revenue recovery. This will help to ensure that recovery is consistent with cost, and that each class maintains the position it is ultimately assigned relative to the company's

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[6]The Commission will reserve discussion of its evaluation of the PRAM until the final order in this proceeding.

overall cost recovery. The Commission agrees with the company that once the class revenue requirement is established by the above method, it may simplify its tariff by recovering each class' share on an equal cents per kWh basis.

V. RATE DESIGN AND TARIFF ISSUES

An important element of this phase of the proceeding is the full examination of the company's proposed changes to rate design. The company's objective for its rate design proposals was to send a stronger and more accurate price signal to its customers regarding the costs of producing energy and, thus, to rely on economic efficiency and market forces to encourage efficient energy usage.

All parties have made proposals or analyses that would improve customer incentives for efficient use of fuel and better match the company's actual costs associated with increased consumption at peak periods and annually. We believe that the company proposals generally take a good step in the direction of greater efficiency, without sacrificing considerations of equity and affordability. We outline our specific decisions by customer class and schedule below.

A. Residential Customers - Schedule 7

1. Customer Charge.

The company has proposed a $5.00 monthly customer charge based on the costs of services, meters and meter reading, and a portion of general costs. This is an increase of $0.45 per month over the current customer charge. This charge was calculated using the Basic Customer method. As discussed in section III.C.3. above, we continue to support use of this method for allocation of distribution costs. Public Counsel suggested a number of adjustments that would put the customer charge at a level below $5.00, but generally supported the company proposal. Commission Staff found the $5.00 level appropriate.

The Commission accepts the proposed $5.00 as reasonable, since it attempts to recover only those charges properly associated with each customer. While it represents an increase over the existing charge, this increase appears reasonable. We again emphatically reject the minimum system approach proposed by WICFUR and discussed by the company.

2. Rate Blocks.

The company has proposed changing its current three block inverted rate structure to two blocks, with the second to start at 800 kWh. This is a modification of the company's original proposal, which would have replaced the current structure with two blocks, with the second starting at 400 kWh in summer and 500 kWh in winter. The 800 kWh proposal was intended to moderate increases in heating customers' bills that would have occurred under the 400/500 block structure, assuming the company's full rate increase were approved. Commission Staff objected to the 800 kWh level as higher than the monthly usage of the average lights and appliance customer and therefore failing to produce a true marginal price signal.

Public Counsel supported a 600 kWh first block, citing two purposes of an inverted rate. The first is to reflect the actual cost of new resources in the end block, so customers can make economically efficient decisions at the margin. The second is to equitably allocate the limited amount of low-cost power on Puget's system.

The Commission will reserve to the final order on the general rate increase filing a decision on the size of blocks. However, we agree that the two purposes identified by Public Counsel are the appropriate bases for determining where the first block should end and the second begin. We note that the Rate Design Task Force also recommended an equitable allocation of the company's low-cost hydro resources among customers.

3. Seasonality.

Current residential rates contain a 5 percent seasonal differential. The company and most other parties agreed that an increase to 10 percent would better reflect differences in the company's winter and summer resource costs.

The Commission agrees that an increase in seasonality better reflects costs, and accepts the 10 percent estimate at this time. We instruct the company to use a six-month definition of winter (October 1 through March 31) in its application of seasonal differentials.

4. Low Income.

The question of separate handling of low income customers arose numerous times in the briefs filed in this proceeding. No party proposed a low income discount rate. SWAP claimed that commercial customer classes' rates have functioned as a subsidy to all residential customers. SWAP would prefer that any "subsidy" be supported by a contribution from all customers. The Rate Design Collaborative also examined the issue of low income rates and concluded that these could not be implemented without legislative intervention.

The Commission agrees with the Rate Design Collaborative that guidance from the legislature is necessary. The question of affordable rates for low income individuals has arisen periodically as low-cost hydro becomes a smaller and smaller component of the company's resource mix. However, providing a rate discount to low income customers may result in a revenue shortfall to be recovered from other customers or stockholders. We believe that the legislature is the proper source for a decision whether it is appropriate to offer special rates to low income households.

5. **Hookup Fees.**

Public Counsel proposed a charge that would apply only for new residential electric space and water heat connections. It would be $200/kW based on installed kW. For a house with 10 kW of space heat and 4 kW of water heat, the charge would be $2800. Public Counsel stated that this would (1) partially pay for the cost of new heating load, thus spreading fewer new costs to all customers; (2) encourage builders to install maximum efficient equipment (to keep installed load down), and (3) encourage developers to seek lots located closer to existing gas mains.

The company opposed establishment of such fees. It claimed that it already obtains all cost-effective conservation in new electric heated homes. According to the company, Public Counsel's proposed charge is not cost-based and appears to be designed to drive customers to alternate fuel sources.

Commission Staff believed this proposal may have substantial merit and recommended that the issue receive further study.

The Commission agrees with Commission Staff that this issue merits further study. The Washington State Energy Strategy recommends that such charges be considered as a means to correct for certain market distortions that make electric heat more attractive to install in certain situations. We would like a collaborative inquiry into the issue, with a report within six months of this order on whether parties are likely to reach a consensus on some form of hookup fee. Natural gas local distribution companies operating in Puget's service territory should be invited to join the collaborative.

B. Commercial Customers -- Schedule 24

The company proposed to split Schedule 24 into three new schedules, serving small users (Schedule 24), medium users (Schedule 25), and large users (Schedule 26). The company averred that this would better reflect size and usage patterns. For new Schedule 24 customers, the company would establish a $5.00 basic charge and set rates across all consumption with a 10 percent differential applied to the winter rate.

For new Schedule 25 customers, the company would establish a higher basic customer charge reflecting customer costs identified by the company cost study. The company proposed two energy blocks, with the first block incorporating a demand charge. The tail block would be set to recover remaining revenues assigned to the class. The company proposed to reflect seasonal cost differentials by setting the winter energy rate 10 percent higher than the summer rate and the winter demand component 50 percent higher than the summer component. Demand charges would be calculated for all adjusted billed demand over 50 kW.

The design of new Schedule 26 would be similar, except there would be only a single energy block.

Public Counsel objected to dividing Schedule 24 into three new schedules based on size. He argued that two new schedules, for serving non-demand-metered customers and demand-metered customers, would create a more cost-based tariff. He pointed out that the costs to provide energy to large volume customers on the proposed Schedule 26 were not significantly different from costs to serve customers on the proposed Schedule 25.

With respect to the design of rates within schedules, parties agreed with the company proposal, with the following exceptions. Public Counsel recommended that the company's proposed seasonal differential for Schedule 25 and 26 customers, which amounts to 20 percent including the demand differential, be applied to Schedule 24 customers as well. Both Commission Staff and Public Counsel expressed concern about the apparent "declining rate" aspect of Schedules 25 and 26.

Public Counsel argued that the company proposal tends to encourage inefficient energy use. Public Counsel argued that PURPA[7] provides that the energy component of a rate may not

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[7] Public Utilities Regulatory Policy Act of 1978. 16 USC § 2624.

decrease unless the utility demonstrates that its costs attributable to that energy decrease as consumption increases. He concluded Puget has not made this demonstration.

The company claimed this rate structure is needed to mitigate a disproportionate increase for "low load factor" customers. Public Counsel recommended that the Commission reject the company's solution in favor of a demand charge that would be capped at a specified amount per kWh. Public Counsel also pointed out that the company's proposal to offer lower rates to Schedule 26 customers makes little sense when the company's cost study shows current revenues from these customers are lower relative to cost of service (115%) than revenues from the group proposed for Schedule 25 (118%).

The Commission accepts, for this case, the company's proposed treatment of Schedule 24, and the rate designs proposed for new Schedule 25 and 26 customers. The changes proposed by the company represent an improvement in the accuracy of the cost signals and will provide for better alignment of costs with rates, while allowing customers the opportunity over time to adjust their usage patterns. We share Commission Staff's concern with apparent declining rates for Schedule 25 and 26 and think that Public Counsel's proposal for capping demand charges at a certain level per kWh merits further investigation. We instruct the collaborative to study this issue.

C. <u>Irrigation Customers -- Schedules 29 and 35</u>

The company currently offers two special tariffs for irrigation customers. Service under these tariffs is limited to customers who qualify for an irrigation credit provided by the Bonneville Power Administration (BPA). The BPA is considering eliminating the credit in its current rate proceeding. The company proposed adjusting these schedules to make the basic charge and winter rates similar to other general service schedules. Public Counsel would eliminate these schedules and serve the customers on Schedule 25. The Commission Staff proposed that Schedules 29 and 35 be eliminated if the BPA, in fact, eliminates its credit. SWAP would like to see eligibility for the schedules extended to its members and other summer peaking customers.

The Commission agrees with the Commission Staff's proposal to eliminate Schedule 29 and Schedule 35 if BPA eliminates its irrigation credit. In the meantime, we agree that the company should make the basic charge and winter rates similar to those of other general service schedules. We reject the proposition that SWAP customers could be served on an appropriate cost basis under either of these schedules.

D. Primary General Service -- Schedule 31

The company proposed to leave this schedule unchanged, except to add a rider offering a credit for the ability to interrupt service. Intervenor SWAP recommended that summer peaking customers from this schedule be allowed to move to a new schedule with rates that better reflect the usage patterns of these customers.

In the alternative, SWAP proposed that the design of Schedule 31 rates be changed to incorporate a steep seasonal differential. SWAP argued strongly that the company's generation and transmission demand costs should be recovered only in winter, to reflect the fact that they are caused in winter. SWAP added that the company's use of a percentage based on avoided cost to reflect the seasonal energy differential also understates the company's actual seasonal cost differential. To recover costs properly, according to SWAP, the Commission should require the company to recover a much higher portion of Schedule 31 customer revenues from winter consumption. SWAP pointed out that this would allow each customer in the class to pay close to its cost of service, even if its usage pattern were different from that of the class as a whole.

The Commission is not persuaded by SWAP's claims. However, we agree with Commission Staff that, while the record is insufficient on this issue, a cost-based summer peaking rate may have some merit. We direct the company to conduct an analysis of these customers' loads to determine the relative merits of such a schedule, and to include SWAP in its collaborative activities.

E. All-Electric Schools -- Schedule 43

This schedule provides an interruptible rate for all-electric schools. In the case of Schedule 43 the company and Commission Staff have worked out an arrangement which would maintain the availability of the tariff for one year for new all-electric schools that are built incorporating energy efficiencies approved by the Washington State Energy Office. Schools currently on the schedule must also complete cost-effective conservation, while dual fuel schools will be required to take service under Schedule 31.

The Commission accepts the arrangement proposed by company and Commission Staff.

F. Interruptible Service -- Schedule 46

This is the remaining schedule under which the company currently offers interruptible service. Both summer and winter peaking customers take service under this schedule. The company has proposed to replace its traditional interruptible schedules with an experimental program under which it would purchase specific amounts of interruption from customers taking service on the company's firm schedules. The company would freeze its existing interruptible schedules, thus, closing them to new to new customers. The company proposed that some customers be able to take advantage of new interruptible credit programs, if approved, and other customers currently on the schedule remain for an indefinite period.

Commission Staff and Public Counsel agreed with the company, except that Public Counsel recommended that existing customers who wish to remain on the schedule execute contracts wherein they agree to provide advance notice of changes in consumption greater than 10 MW. SWAP strongly opposed closing the schedule to new customers, arguing that summer peaking customers are unlikely to benefit from proposed new interruptible credit programs. SWAP also opposed any requirement of advance notice.

The Commission does not agree to close Schedule 46 at this time. We understand that the company intends to put its approach to interruption of service on a more cost-effective basis, and proposes a first step toward doing so by offering experimental credit programs. However, closing Schedule 46 to new customers in the manner proposed is very likely to be discriminatory. Existing businesses will continue to enjoy the benefits of a lower, "interruptible" rate, while their competitors will have no choice other than service under higher-rated, firm schedules.

Until an alternative is generally available, we reject the proposal to close this schedule. If Puget's experiments should prove successful, it may be appropriate to eliminate this schedule entirely.

In addition, the Commission rejects Public Counsel's proposal for advance notice. We believe that statutory language in RCW 80.28.110 offers sufficient opportunity for the company to plan its system and to require "reasonable notice," as specified in the law.

G. Experimental Interruptible Service -- Schedules 36, 38 and 39

The company proposed three voluntary tariffs to experiment with new ways to integrate into its resource planning the ability to interrupt service. Customers will be paid either for "firm" interruption, or for "voluntary" interruption. The firm version requires customers to sign a contract for a specified level of agreed-upon interruption at specified times. Their payment will vary with the amount and duration of the interruption. These customers will be paid a reservation fee ("credit") even when not interrupted. Voluntary interruptible customers would be paid if and the company actually interrupts service. These schedules are limited to 10 customers each, and require a minimum monthly winter load greater than that of most customers represented by SWAP.

All parties agreed with these proposals, except that WICFUR argued for a higher reservation fee. Public Counsel pointed out that short-term interruption of service cannot be valued the same as the long-term fixed cost of providing firm capacity. SWAP did not oppose the schedules, but argued that their existence did not justify closing Schedule 46.

The Commission believes it is reasonable for the company to offer these interruptible programs as experimental tariffs available to customers on its firm Schedules 26, 31, and 49. We applaud this effort to discover innovative and cost-effective alternatives to new peak generating resources. We agree with Commission Staff and Public Counsel that the level of the company credit is reasonable. We continue to be interested in extending these innovative approaches to residential customers. We instruct the parties to undertake a further examination of interruptible credits for residential users in the collaborative, with the objective of developing a workable program.

H. Optional Marginal Cost -- Schedules 30 and 48

The company proposed additional experimental tariffs designed to provide incentives to large customers to minimize consumption over historical levels. The company would offer a lower rate for consumption calculated at 75 percent of a historical period, with consumption above that amount charged at a marginal rate. These tariffs would be available on an optional basis to customers currently taking service on Schedules 31 and 49. WICFUR supported the company position.

Both Commission Staff and Public Counsel expressed interest in the concept of marginal rates for large users, but raised concerns about the likelihood that the tariffs would function as intended. Commission Staff argued that only customers intending to reduce their load would be likely to sign up. Public Counsel also argued that, until customers in this class pay rates equal to their fully allocated cost of service, such credits will move them further from parity and shift costs to other classes who are already bearing more than their share.

The Commission will not authorize implementation of the company's optional marginal cost tariffs at this time. The proposal does not seem to be structured as an effective experiment. To pass muster, it is essential that customers who sign up are actually changing their consumption patterns or increasing their efficient use of power in order to receive the benefits of lower rates. We are not satisfied that this program would achieve the intended result.

I. Low Power Factor -- Schedule 80

This schedule would create a new charge designed to recover capacity costs created by customers with low power factors. The company argued that this is necessary to properly recover the costs that such customers impose. Commission Staff and FEA agreed with the company, as did Public Counsel. However, Public Counsel recommended that the Commission instruct Puget to allow customers to pay the cost of having capacitors installed to correct their power factors, and to waive the application of the Schedule to these customers.

SWAP opposed the charge, arguing that it is a "penalty" rather than a cost-based charge. SWAP asked, if the company were allowed to impose a new power factor adjustment, that it be calculated separately for each schedule and reflect the average size and power factor for customers on that schedule, rather than for the class as a whole.

The Commission accepts the company's argument that a new charge is needed. However, we agree with Public Counsel and SWAP that if installation of a capacitor is less expensive, customers should have the option of paying for such installation. Further, we accept SWAP's demonstration that there are economies of scale in correcting low power factors. We therefore direct the company to redesign the tariff in order to allow customers to pay for the installation of capacitors as proposed by Public Counsel. For those who must still pay the new charge, the charge shall be calculated based on the average cost by schedule.

J. Firm Resale

The company serves a number of wholesale customers whose rates are under the jurisdiction of the FERC. The company's wholesale customers are currently paying rates well below cost, as indicated by the cost study we have approved. On rebuttal, the company proposed that these customers be allocated a revenue requirement based on full costs identified in the cost study. The Commission agrees that it is reasonable to allocate wholesale customers the full costs of providing service to them. An adjustment will be made in the revenue requirement order.

VI. PUBLIC PARTICIPATION

The Commission held three hearings for the purpose of taking testimony from members of the public about these consolidated filings. 25 members of the public testified on June 21 at Bellingham, 20 testified on June 23 at Olympia, and 23 testified on June 24 at Renton.

Illustrative Exhibits Nos. 871, 873 and 874 contain statements and materials brought by witnesses to the three hearings. Illustrative Exhibit 872 contains letters and materials sent by persons who did not necessarily attend the public hearings.

Several witnesses addressed rate design issues during the public testimony.[8]

Four witnesses were members of Puget's Rate Design Task Force. Puget formed the Rate Design Task Force to get residential customer input on rate design issues.[9] James A. Young, chairperson of the Rate Design Task Force, sponsored and described the group's final report. Willard Brown commended the

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[8] Witnesses also addressed issues which are being considered in the general rate case. Many of these witnesses gave their opinions regarding the proper level of rate increase. The testimony of witnesses regarding issues from the general rate case will be discussed in the order in that portion of these consolidated cases.

[9] Company witness Mr. Knutsen describes the process in his testimony at Ex. T-1, pp. 6-7. Mr. Hoff also describes the group's participation at Ex. T-8, pp. 7-8. Mr. Hoff sponsored as an exhibit the Rate Design Task Force's final report, dated February 20, 1992 (Ex. 10).

company's responsiveness to customer ideas during the process. Frank R. Fahland urged the Commission to fully consider the Task Force's recommendations. Edward M. Gardiner presented a minority report from the Rate Design Task Force.[10]

The Rate Design Task Force's final report contained several pages of recommendations. Among the recommendations were the following:

- Each user should pay a fair share of the cost of electrical power, based on a Commission-approved cost-of-service study.

- Each class should receive a proportionate share of the low-cost energy benefits from hydro, spread between all consumer classes and allocated by power consumption.

- No low-income rate should be established. A centralized low-income utilities credit system should be established, based on the results of a pilot program.

- Residential rate design should include a base charge based on an allocation of Puget's fixed costs, a first block rate based on an allocation of low-cost hydro energy, and a second block based on an allocation of thermally-generated and contingency-purchased energy. The company should also explore interruptible rates and time-of-use rates for residential customers.

Mr. Fahland stressed that each customer class should bear its properly-allocated cost, there should be a Commission-approved cost-of-service model, the base charge should be increased to $15 per month, and an incentive for reduced expenses should be available to Puget.

Mr. Gardiner's minority report recommended establishment of a demand charge to track unexpected weather conditions. He recommended the PRAM be eliminated as unnecessary after the Commission established direct metering of demand.

Janet L. Yates recommended commercial, industrial, and residential ratepayers be charged similar rates. Ms. Yates also opposed low-income rates. In contrast, Don Porterfield supported decreasing rates for low-income customers.

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[10] Exhibit 10 shows that four separate minority reports were filed with the Task Force's final report. Mr. Gardiner's oral and written comments from the public hearing were apparently based on his minority report dated January 31, 1992.

Philip J. Dolan opposed changing the current three-block residential rate to a two-block design, because it would result in too great a rate increase. Jim Whitbeck supported a lower-priced initial rate block of 1200 to 1400 kWh, to represent a basic amount for most households.

Randall South recommended higher rates be charged for new projects causing growth in the service territory. He suggested higher hook-up fees be established for persons who have not previously purchased power in the region.

Many of these witnesses addressed issues which have been proposed and supported by various parties to these consolidated cases. The Commission appreciates the input from customers. The Commission has adopted those suggestions discussed in the sections above.

Based on the entire record and the file in this matter, the Commission makes the following findings of fact and conclusions of law.

FINDINGS OF FACT

Having discussed above in detail both the oral and documentary evidence concerning all material matters, and having stated findings and conclusions, the Commission now makes the following summary of those facts. Those portions of the preceding detailed findings pertaining to the ultimate findings are incorporated herein by this reference.

1. The Washington Utilities and Transportation Commission is an agency of the state of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, accounts, securities, and transfers of public service companies, including electric companies.

2. Puget Sound Power & Light Company (respondent herein) is engaged in the business of furnishing electric service within the state of Washington as a public service company.

3. On April 30, 1992, the company filed tariff revisions reflecting cost-of-service, rate design and rate spread issues. On October 30, 1992, the company filed a general rate case, including updates to cost-of-service, rate design and rate spread issues.

4. The Peak Credit method is an appropriate methodology for classifying production plant. This methodology shapes the allocation of embedded costs according to current demand/energy relationships.

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5. The peak credit factor should be calculated using the 200 highest hours of demand as the peak period.

6. The following should be used in assumptions for the Peak Credit method: The reflection of one-half of a combustion turbine and an 80% capacity factor for the combined cycle combustion turbine are appropriate. Fuel choice for the combustion turbine should reflect a typical year. In this case, the Commission accepts Public Counsel's recommendation of 50 hours of fuel oil and 150 hours of natural gas.

7. Non-generation-related transmission costs should be classified in the same manner as generation-related transmission costs. Use of the Peak Credit method is appropriate.

8. The Basic Customer charge approach is appropriate for classifying distribution costs. The Minimum System method is not appropriate. It should not be litigated in future cases absent technological changes in the electric industry justifying revised proposals.

9. Residential customers' test year energy allocation should be adjusted to reflect normal weather in the development of peak and energy allocation factors.

10. PRAM 3 increases should be spread according to the cost-of-service methodology found appropriate in this case, to ensure that recovery is consistent with cost.

11. For residential Schedule 7, a basic charge of $5.00 per month is appropriate. The Schedule should move from three to two blocks. The size of the blocks will be determined in the order in the general rate case. The blocks will be designed both to reflect the actual costs of new resources in the end block and to equitably allocate the limited amount of low-cost power on Puget's system. A 10 percent winter/summer differential is appropriate, with "winter" defined as the six months October through March.

12. The issue of whether low-income rates are appropriate must be determined by the legislature.

13. Puget's proposed commercial Schedules 24, 25 and 26 are acceptable as a first step in accurately reflecting load characteristics. The company should continue to analyze whether Schedule 25 should be refined to avoid an energy rate that declines for some customers. The issue should be explored in a collaborative setting.

14. Schedules 29 and 35 should be eliminated if the Bonneville Power Administration eliminates its irrigation credit. In the meantime, the basic charge and winter rates should be similar to those of other general service schedules. SWAP companies are not appropriately served under these schedules.

15. Schedule 31 should remain the same, except for availability of the peak interruption rider. The company should investigate, in a collaborative, whether a cost-based summer peaking rate should be offered to customers presently on Schedule 31.

16. The proposal agreed to by the company and the Commission Staff for Schedule 43 should be accepted.

17. Schedule 46 should not be closed to new entrants.

18. The company's proposed Schedules 36, 38 and 39 are appropriate on an experimental basis.

19. Proposed Schedules 30 and 48 are not appropriate at this time.

20. A power factor adjustment should be accepted. The charge should be waived if a customer installs a capacitor. The tariff should be redesigned to allow customers to pay for installation of capacitors. For those who still must pay the power factor adjustment, the charge should be calculated based on the average cost by Schedule.

21. Wholesale customers should be allocated the full costs of providing service to them.

22. The company should convene a Collaborative to study the following issues: weather normalization for all weather-sensitive classes; seasonal differentials; interruptible residential water heaters; cost-based summer peaking rates; declining energy blocks in Schedule 25; and optional marginal cost tariffs.

23. The company should convene a Collaborative to study hookup fees, and sending correct economic signals regarding the cost to society of electric space heating. The Collaborative should include local gas distribution companies operating in Puget's service territory. The Collaborative should report within six months its conclusions regarding hookup fees.

24. SWAP and FEA should be invited to participate in the collaborative groups contemplated in this order. The company should make a good-faith effort to determine when other interested entities should be included in collaborative groups.

25. Documents marked for identification as 81, 82 and 90 are the responses to Bench Requests 6, 7 and 8, respectively. The company's original May 27 response to Bench Request 7 was rejected by Commission letter of June 9. On June 16, the company filed a replacement response. Exhibits 81, 82 (which is the replacement response filed June 16), and 90 should be entered into the record.

From the foregoing findings of fact, the Commission enters the following conclusions of law.

CONCLUSIONS OF LAW

1. The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of this proceeding and the parties thereto.

2. Cost-of-service, rate design and (to the extent covered in this order) rate spread determinations made in accordance with the decisions in this order will result in a distribution and structure of rates that is fair, just and reasonable.

3. Further study is necessary on some issues, as outlined in the discussion and findings of fact.

4. The company's tariffs as filed do not comply entirely with the determinations of this order. They should be rejected. New tariffs should be filed incorporating the cost-of-service, rate spread and rate design determinations of this order. Those tariffs should be filed after the order in the general rate case.

5. All motions consistent with this order should be granted. Those inconsistent with this order should be denied.

Based on the above findings of fact and conclusions of law, the Commission makes the following order.

ORDER

THE COMMISSION ORDERS That:

1. The company's tariffs are rejected.

2. After the completion of the general case, the company is authorized to file revised tariffs incorporating the cost-of-service, rate design and rate spread determinations made in this order.

3. Exhibits 81, 82 and 90 are entered into the record.

4. All motions consistent with this order are granted, and those inconsistent with this order are denied.

DATED at Olympia, Washington, and effective this 16th day of August 1993.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Sharon L. Nelson

SHARON L. NELSON, Chairman

RICHARD D. CASAD, Commissioner

Richard Hemstad

RICHARD HEMSTAD, Commissioner

NOTICE TO PARTIES:

This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-09-810, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-09-820(1).