PUGET SOUND ENERGY

July 1, 2003

VIA FACSIMILE AND US MAIL

Ms. Carole J. Washburn, Executive Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
Olympia, Washington 98504-7250

Re: Docket Nos. UE-011570 & UG-011571 Time-of-Use Compliance Filing

Dear Ms. Washburn:

The purpose of this filing is to comply with the Commission's Twelfth Supplemental Order: Rejecting Tariff Filing; Approving And Adopting Settlement Stipulation Subject to Modifications, Clarifications, and Conditions; Authorizing And Requiring Compliance Filing in Docket Nos. UE-011570 and UE-011571 (the "Order"). The attached Time-of-Use milestone report meets the requirement in the Commission's Order. The requirement for July 1, 2003, is the following:

Final Report and Recommendations by July 1, 2003: Conclusions regarding the observed effects of TOU pricing; the implications of those conclusions for the expected effects of TOU pricing during periods of wholesale price stability and wholesale price instability; and recommendations regarding whether or not the program should continue in its current form, in an amended form, or be discontinued.

The submission of the attached document fulfills that requirement and concludes the work of the Time-of-Use Collaborative. The Company would like to thank all those who participated in the collaborative effort.

Sincerely,

George Pohndorf
Director, Regulatory Initiatives

Attachment

cc: Simon J. ffitch
Kirstin Dodge
Service List

Puget Sound Energy, Inc. • P.O. Box 97034 • Bellevue, WA 98009-9734

July 1, 2003 Time-of-Use Milestone Report

Purpose of Report:

This report is being submitted in compliance with the Commission's Twelfth Supplemental Order in Docket No. UE-011570/UG-011571. This Order required, on page 17, the following:

> **Final Report and Recommendations by July 1, 2003:** Conclusions regarding the observed effects of TOU pricing; the implications of those conclusions for the expected effects of TOU pricing during periods of wholesale price stability and wholesale price instability; and recommendations regarding whether or not the program should continue in its current form, in an amended form, or be discontinued.

This is the final report by the Time-of-Use (TOU) collaborative, which was established in the settlement stipulation. As the Commission is aware, the program was terminated in November 2002, so a discussion of whether the program should continue is no longer relevant.

Conclusions on Time-of-Use Pricing Pilot

1. Summary of Cost Effectiveness Methodology

As noted in the Collaborative's November 1st filing, Charles River Associates (CRA) was retained by PSE to perform a cost-benefit analysis of the TOU pilot. CRA performed this analysis using its cost-effectiveness model (CEM) that uses a codified set of formulas derived from the California Standard Practice Manual for evaluating demand-side programs and innovative rate programs (see February 3, 2003, report to Commission describing CRA model in detail. The standard practice methodology laid out in this Manual has been adopted by regulatory commissions nationwide, and is being used in several foreign countries.

The CEM model produces net present values of the costs and benefits as measured by the following Standard Practice Tests: Participant Cost Test, Total Resource Cost (TRC) Test and the Ratepayer Impact Measure (RIM) Test. To perform the Standard Practice Tests, the model utilizes the inputs shown in Appendix 1. CEM was not used to measure consumer surplus effects (i.e., the extent to which consumers must make sacrifices in order to achieve the economic savings from load changes.) The following table summarizes the collaborative parties' base case model runs:

Summary of Cost-Effectiveness Results Comparison Table

Present Value Net Benefits ($ millions) (over 10 years)

	TRC Test	Participant Cost Test	RIM Test
Commission Staff Base Scenario (04/23/03)	-$10.60	-$17.59	$5.56
Public Counsel Base Scenario (04/25/03)	-$6.73	-$5.30	-$0.68
Puget Sound Energy Historic Period Scenario (04/24/03)	-$1.78	-$2.41	$0.47
Puget Sound Energy Future Period Scenario (04/24/03)	-$10.19	-$10.44	-$3.96

Footnote to table: Negative numbers indicates that costs exceed benefits, positive numbers indicate that benefits exceed costs.

CRA has run the CEM model with variations of these inputs to evaluate the cost-effectiveness of the TOU pilot under different scenarios and sensitivity analyses as requested by parties in the Collaborative. Many of the CRA model runs were done to test sensitivities of the inputs that are more difficult to quantify. These sensitivity analyses will enable the parties of the Collaborative to better understand the effect specific inputs have on the overall program cost-effectiveness. See Appendices 2, 3 and 4 for CRA output of all scenario runs for WUTC Staff, Public Counsel, and PSE, respectively.

2. Discussion of Each Party's Inputs That Are The Same

<u>WUTC Staff, Public Counsel & Puget Sound Energy</u>

First, the Collaborative came to the general conclusion that the Marginal Energy Cost data from Aurora contains the market value of the Marginal Generation Avoided Energy and Capacity Costs; therefore, the Collaborative agreed to utilize the Aurora model output. This process models energy prices per kWh--by year, season, and time-of-day--through the planning horizon. As capacity costs are included in the Aurora model output, no additional cost per kW-year is necessary. This reduced the Collaborative's original calculation of avoided cost for load reduction by removing the additional $8 per kW-year of production capacity costs.

Second, the Collaborative came to the general conclusion that the Marginal Transmission and Distribution System (T&D) Avoided Capacity Costs is $35.32/ kW-year. (However there is disagreement on the phase-in of these capacity cost savings).

The determination of the T&D avoided capacity costs was a result of efforts by PSE distribution and transmission system engineers who reviewed ten years of capital budget expenses to identify the cost of projects related to growth in demand for capacity. This approach measures long-run costs pertaining to transmission lines, substations, and feeders where work was done that added to or expanded the existing T&D system, and excludes the costs of new business and maintenance. This level is lower than that originally used by the Collaborative of $53.60 per kW-year.

Other inputs such as the Inflation Rate, the Discount Rate, the Line Loss, the Reserve Margin, the Planning Horizon and the Incremental Load Reduction were generally agreed to by all the parties submitting inputs to the Cost Effectiveness Model for purposes of this report, with sensitivity analyses as deemed appropriate by individual parties.

3. Discussion of Each Party's Inputs and Sensitivity Analyses That Are Different

Discount Rate

WUTC Staff: Staff's base case utilized PSE's after-tax cost of capital of 7.30%, which is the standard method for evaluating utility DSM programs. Staff did run a sensitivity analysis for this input at 8.76% (before tax cost of capital). It could be argued that a determination of whether this program is cost effective should be a measurement of whether consumers are better off, therefore, the consumer's cost of money should be used as the discount rate. Staff recognizes that there is no evidence as to what the actual consumer's cost of money is, however, the issue is only one of degree in measuring the net costs since every year in the ten-year analysis performed by CRA for Staff's base case resulted in net costs.

Included in Appendix 2, are the CRA model run results dated both April 23, 2003, and January 14, 2003. The results included in the April 23, 2003, memorandum from CRA represent staff's current thinking as to the proper inputs in the cost effectiveness study of this program. The results shown in the January 14, 2003, memorandum from CRA were intended to measure various sensitivities.

Planning Horizon

WUTC Staff: Staff believes that a longer horizon is more appropriate than the 10 years utilized by CRA. Since the conversion to TOU rates may represent a permanent impact on the customer load patterns, the comparison of costs and benefits for an extended horizon would be appropriate as long as it has an impact on the net present value.

However, because it would be difficult for CRA to expand the horizon, Staff came to agreement with PSE and CRA that CRA would provide the year-by-year results to determine if any turn around in net benefits was taking place. In the Staff base case there did not appear to be a turn around in the net benefit calculation in later years.

Residential Customer Participation

WUTC Staff: At the beginning of the Time-of-use pilot program (May 1, 2001), residential customer participation was approximately 296,000 customers. In Order to measure the costs and benefits of a mandatory program, Staff assumed a constant level of participation at 300,000 customers in an attempt to mimic a mandatory program.

Public Counsel: Public Counsel has assumed participation levels which we believe are consistent with the settlement and stipulation of the general rate case. This assumes that during the pilot period, 300,000 participants would be in the program. During the first year following the settlement, 100,000 of these would opt off of the program, leaving 200,000 participants. At the end of the period called for under the settlement, customers not saving at least $1.00 per month in TOU rates, enough to offset the incremental meter reading and billing cost, would be defaulted off of the TOU rate, leaving 30,000 long-term participants.

Puget Sound Energy: Puget Sound Energy utilizes 300,000 residential customers for the historic cases. For the future period scenarios a number of 900,000 residential customers is utilized in an attempt to measure the effects of a new full-scale mandatory pricing program.

Cost to Achieve Load Reduction

WUTC Staff: This input is intended as a measurement of the cost to the consumer to achieve the one percent load reduction. The load reduction was likely achieved by a combination of behavioral changes and the installation of energy-efficient measures. Therefore, these costs may include tangible costs such as the purchase of a timer or CFLs and may also include intangible costs such as lost opportunities and inconvenience. There is no input for costs to participants to achieve a shift in load.

Staff does not believe that there is sufficient evidence to set these participant costs at any specific amount since we have insufficient information on how the load reduction was achieved and its long-term persistence. Originally, Staff included two scenarios of costs to test the sensitivity of this input on program cost-effectiveness. Staff believes that the impact of this input is linear and can be extrapolated to whatever level of costs one wants to assume. For our final base case, Staff used a cost of 1.5 cents/kWh. This number is less than Public Counsel's input but more than PSE's input. The number is weighted more towards customer purchases of low-cost efficiency measures as a result of TOU pricing, than higher-cost measures such as insulation or windows.

Staff has not attempted to explicitly include a cost for behavioral changes (although we believe the lower-cost efficiency measures may be a better proximate for this cost than the higher-cost measures). Staff understands the concept of a cost of inconvenience. However, because the measurement of such costs, and the possibility that other customers may receive intangible benefits—such as having to pay only the cost caused or having the ability to control their bills—Staff does not believe it appropriate to include intangible costs in the input calculation at this time.

Public Counsel: The assumed load reduction is a combination of conservation, curtailment, and fuel switching. Each of these carries a cost.

The cost of conservation was assumed to be equal to the average cost of conservation in the Northwest Power Planning Council's 4th Plan (See Figure 6-2, Page 6-7). We consider this conservative, because the lowest cost conservation might well have been achieved without the TOU program.

The cost of curtailment was assumed to be equal to one-half of the retail rate; this is based on an assumption that consumers would NOT curtail without any compensation, and WOULD curtail in response to the TOU price signal of somewhat above $.07/kwh. Clearly the "cost" to consumers lies between these two values – one too low to encourage the behavior, the other high enough to do so. On average, we conclude that the average cost to consumers of this curtailment (foregone value of energy use) has a cost of more than $.03/kWh.

Finally fuel switching would be to a combination of natural gas and wood. Natural gas, at $.80/therm, has an electric-equivalent cost of about $.04/kwh. Wood, at $100/cord has an electric-equivalent cost of about $.05/kWh. The assumption of $.03/kWh is a very conservative estimate of this cost.

Taking these three together, an assumed average cost to achieve the load reduction of $.03/kWh is very conservative.

Puget Sound Energy: Puget Sound Energy selected an estimate of cost to achieve load reduction and conservation based on some real results from our actual residential customers on the time-of-use pilot, historic conservation program experience, and sound economic principles. PSE based its load reduction costs on measure cost data (excluding administrative and other non-measure program costs) from its residential compact fluorescent program – as proxy for low cost measures – and the Low Income Weatherization program – as proxy for high cost measures. That is why we believe that this combination is a reasonable estimate for what actual residential customers would implement.

Clearly not all customers will install energy efficiency measures in order to achieve their load reduction, that is why Puget Sound Energy used an estimate of what the group as a whole likely spent on conservation measures. Survey results presented in PSE's October 30, 2001 report to the WUTC on the TOU pricing pilot indicate that many customers were able to reduce their load without installing any energy efficiency products. In those instances where customers did install energy-efficient products, the survey indicated that most customers installed low cost items, such as compact fluorescent bulbs. In the survey of customers on time-of-use rates, about 10% stated that they installed energy efficiency devices. In the spirit of collaboration for this study, Puget Sound Energy tripled the amount of customers who said they installed energy efficiency products. Thirty percent of customers installing energy efficiency devices is a reasonable estimate.

Elasticity Factors

WUTC Staff: Staff did not propose any sensitivity on these inputs, and utilizes those calibrated by CRA. CRA calibrated the elasticities to produce the load impacts that the Brattle Group measured, on a seasonal basis, for the cost-effectiveness model (CEM). The CEM predicts an annual usage drop (i.e., load reduction) as a result of the TOU pricing. Staff subtracts this usage drop (of .313% in the Staff scenario) from the one percent total load reduction input.

Public Counsel: Public Counsel accounted for all load reductions in the "Incremental Load Reduction" category, rather than in the "elasticity" category. This was necessary, given the constraints of the CRA model, to ensure that the cost to achieve all load shifts (whether conservation, curtailment, or fuel switching) was captured. Including this load reduction in the Elasticity Factor would have required what we understood was a significant modification of the CRA model. The total load reduction assumed is identical to the base case assumptions of Staff and PSE.

Puget Sound Energy: The load impacts of the TOU Pricing Pilot were the subject of an econometric/statistical analysis of billing data from June 2001, the inception of the TOU pilot, until August 2002. This analysis was conducted by the Brattle Group and reviewed extensively by the Collaborative. The results showed an overall average peak period load shift for residential program participants of 5% per month, which remained very steady from the beginning of the analysis period to the end (fourteen months). Econometric comparison of the TOU participants to the control group who received information yielded statistically robust results that clearly show TOU pricing participants shifted loads away from peak pricing periods. Because of the large size of this pilot program, the sample sizes used for the analysis were very large. It seems intuitively logical that the magnitude of this impact would be larger if TOU pricing participants had been compared to a control group of "pure" non-participants, although this effect was not directly measured. CRA developed price elasticities for the cost-effectiveness analysis that were calibrated to the load impact results obtained by Brattle.

Environmental Adder Applied to All Pricing

WUTC Staff: Staff's base case includes an adder to marginal generation costs of 5 mills per kWh during all periods. Staff's base case is intended to measure the environmental benefits of load reduction. A load shift, under this scenario, would result in a benefit in one period and an offsetting harm in another, thus producing no net environmental effect for shifting, but it does capture an environmental benefit for conservation. Staff does not believe that the environmental costs or benefits associated with generation are linear with the incremental costs of generation, thus we do not apply a 10% adder (as is used for conservation) to marginal costs. The 5 mills per kWh represents 10% of a 50 mill per kWh resource.

Staff's base case does not include a benefit or harm caused by the shifting of load to the economy period. Load shifting may have an environmental effect (via emissions) as a result of changes in generation fuel consumption. While the theory that economy period operations may, on average, be running an incremental resource with greater environmental impact than the incremental resources during the peak period (coal versus some type of gas), the opposite may also be true. Without a study to determine what those effects may be, it seems premature to assume that shifting either benefits or harms the environment. However, in order to determine the sensitivity of such a cost or benefit, if it does exist, Staff ran a sensitivity of 5 mills in the economy period only. It would appear that this item should be linear in the model results.

Public Counsel: **(Economy Period):** It is widely recognized that the marginal generating resource in the western system during on-peak hours is natural gas. It is less well understood that the marginal resource during off-peak periods is often coal. The cheapest coal plants in the west (e.g., Colstrip, Bridger, IPP) operate very close to the limits of their availability. Conversely, those with higher fuel costs (Centralia, Boardman, Springerville, Valmy) typically operate significantly below their availability during off-peak periods. It is these power plants that are often the marginal resources during off-peak hours. Our experience over the past two decades with the named coal plants above indicates that many are subject to economic dispatch during night-time hours.

Use of coal carries an incremental environmental (CO_2) emission cost that is about two - three times that of natural gas units. At an assumed CO_2 value of $15/ton (the value selected by the Northwest Power Planning Council's Regional Technical Forum, of which PSE and WUTC Staff are both members), this translates into approximately $.01/kWh for all shifts from gas to coal. The Environmental Adder assumption of $.005/kWh is based on an estimate that half of the load shifting achieved by TOU resulted in gas to gas shifts (i.e., no change in environmental cost), and half resulted in gas to coal shifts.

<u>Puget Sound Energy:</u> Puget Sound Energy cases and scenarios include an adder to marginal generation costs of 5 mills per kWh during all periods. This estimate was used in the spirit of consensus of the collaborative process for this effort. Puget Sound Energy is interested in how the cost of environmental externalities associated with compact fluorescent lightbulbs and other conservation program are modeled in Standard Practice Cost Effectiveness tests. This might give some direction to future ways environmental costs can be modeled for demand-response programs.

Incremental Load Reduction Savings

<u>WUTC Staff:</u> Staff's base case input for this item (sometimes called **incremental conservation savings**) is intended to complement the results of applying the elasticities to the base load to achieve the actual load reduction assumed in the scenario. Staff proposes to utilize a *total* load reduction of 1% based on the review of data and studies provided by PSE, which compare customers on TOU rates to customers without TOU rates or TOU information. The incremental load reduction that Staff uses in the base case is 0.687%. This was calculated by subtracting the load reduction identified by CRA that is embedded in the price elasticities (-.313%) from the total load reduction of 1%.

Marginal Transmission and Distribution Costs

<u>WUTC Staff:</u> In the base case, Staff utilizes the collaborative agreement on the long-run transmission and distribution (T&D) avoided costs of $35.32/ kW-year. However, these avoided costs represent long-run savings, similar to the marginal generation capacity

avoided costs. The fact that these T&D benefits would take time to be fully realized was evident from the discussions we had with PSE staff. On the generation side, the long-run benefits are phased in through the Aurora model. Thus, in an attempt to see if there was a material impact on cost-effectiveness results, Staff proposed what we believe is a modest phase-in (5 years) to achieve the T&D benefits. Staff believes that this reduction in the T&D benefits is entirely appropriate and should be considered in all present value calculations.

Puget Sound Energy: Puget Sound Energy utilizes the time-of-use collaborative agreement on the long-run T&D avoided costs of $35.32/ kW-year. Puget Sound Energy did not think it was necessary to phase in the benefits of avoided costs of the T&D system since the estimate of $35.32 kW/year was an annualized average representing many years and the Cost Effectiveness Model presents its results as a Net Preset Value of costs and benefits that takes into account a discount rate. For purposes of determining whether there was a breakeven point, Puget Sound Energy modeled a future year sensitivity that showed the TOU pilot would be cost effective at $45.60 per kW-year.

Incremental Meter Reading and PEM Costs

WUTC Staff: Staff's base case uses $1.05 per customer, per month, which was provided by PSE and reviewed. It should be recognized that this amount only includes the direct variable costs of running the program. It does not include any start-up, promotional, or customer handling costs, which would need to be added to the analysis of any future program. For purposes of determining where the incremental cost breakeven point was, Staff ran a sensitivity analysis for a 50-cent reduction in incremental costs. Only under this scenario did the program show positive net benefits in the TRC test.

Puget Sound Energy: For purposes of determining whether there was a breakeven point for a cost effective Total Resource Cost test, Puget Sound Energy modeled a future year sensitivity that showed the TOU pilot would be cost effective at $0.92 per customer, per month.

4. Discussion of Overall Results of Cost Effectiveness

WUTC Staff

The results of staff's base case, as well as the base case of both Public Counsel and PSE, indicates that the program is not cost effective. These determinations are based on the factors that are relevant to PSE's current situation. Staff's scenario is intended to determine whether the program meets a total resource cost (TRC) test. In staff's scenario, the participating customers paid all of the costs. The RIM test in this scenario indicates a net benefit of $5.56 million (See CRA memo, Appendix 2). Staff's scenario, as indicated before, is intended to mimic a mandatory program where all 300,000 customers would be participating. Therefore, the results of staff's scenario indicate that, excluding PSE's program cost, there is a net benefit. This is indicated by the results of the RIM test where only benefits and no costs are included. When costs are included, total rates and net costs to all ratepayers would increase as indicated by the TRC test results.

Certain of these factors could substantially affect the outcome of the program and the net result of the analysis. Staff notes two inputs to the model that have a significant impact; namely the incremental costs of the program, and the time of day cost differential. Other factors such as the customer cost of conservation, the phase in of long-run T&D benefits, or the potential environmental cost of shifting from peak hours to economy period have minor impacts on the net cost effectiveness of the total resource cost test.

In a prior sensitivity run, staff requested that the variable costs of the program be reduced by 50 cents per customer per month. This change resulted in an increase in the benefits of approximately $25 million over the ten-year program. Therefore, **totally eliminating** the incremental costs of the program (a reduction of $1.05 per customer per month) would result in staff's base case being changed from a net cost of $10 million to a net benefit of approximately $43 million. Of course it is virtually impossible that the costs of the program would decline to zero. But, in an attempt to put this hypothetical into perspective, a mandatory, zero-cost, all-residential program would produce a net benefit of only 1.1% of the net present value of PSE's ten-year revenue requirement. Therefore, assuming that PSE can reduce the costs of the program by about 50%, a mandatory all-residential program would yield a net benefit of only 0.4% of PSE revenue requirement.

The second major factor influencing the output of the CRA model is the differential between peak and off-peak system costs. The impact of increasing the differential of this input is substantial. The cost differential used in staff's scenario is the best estimate of the long-run cost differential between peak and off-peak power supply. In situations with higher reliance on planning for capacity than the Pacific Northwest is currently experiencing, a greater differential between the costs of peak and off-peak power is likely. A higher difference would have a direct impact on the NPV calculation, increasing the value of shifted load. Further, a greater long-run differential in power costs may support a greater differential in price. A greater price differential when fed into CRA's model and coupled with CRA's price elasticities would yield greater shifting (Note: greater shifting is not documented by the Brattle study or any PSE study). It should be noted that the price differentials used during the original phase of the program and used in Staff's scenario are generally supported by the long-run cost differentials of power supply, transmission, and distribution.

Public Counsel

The key differences between the Public Counsel scenario and the Staff and PSE analyses are the number of participants, and the cost to achieve load reductions. The first of these reflects a fundamental difference in approach, while the latter is a significant difference in assumptions.

Participation Rate: Public Counsel assumed a declining participation rate, based on the assumption that the terms of the settlement stipulation would be adhered to. That stipulation provided for imposing a direct charge on program participants equal to a portion of the incremental meter reading and billing costs. It further provided for removing from the program those customers who could not save at least the amount of the incremental charge, unless they requested to remain in the program.

The analyses by other parties do not use an incremental program cost that is materially different from the $1.00/month participation charge embodied in the settlement stipulation. The rate design assumed by Public Counsel and the other parties reflects the rate design in the settlement stipulation, which in turn was designed to reflect the full time-of-use cost differences on the PSE system in the TOU rate differentials. The preliminary analysis by PSE, at the end of the first three months of the pilot program under the settlement stipulation, was that 94% of customers did not save at least the $1.00 participation fee through TOU shifts. The long-term participation rate of 30,000 assumed by Public Counsel reflects a 90% reduction from the original pilot program level of 300,000. This is a participation level consistent with the requirement of the settlement stipulation that customers not saving money be defaulted off of the TOU rate (subject to customer choice to remain on the TOU rate). A higher level of assumed participation implies that even customers that were receiving the full system benefit of their load shifting but could not even save the incremental meter reading cost would be required to remain on TOU pricing. This seems like an assumption that these customers would be required to participate in a program that was not in their interest, and not in the collective societal interest.

We note that this assumption causes a much lower negative net system present value than the staff or PSE base scenarios, simply because a much smaller number of customers were assumed to remain in a non-cost-effective program.

Cost To Achieve Load Reductions: PSE and WUTC Staff have identified costs to achieve load reductions which are extremely cheap -- $.006/kWh and $.015/kWh respectively. Frankly, if we believe that PSE had load reduction opportunities that were this cheap, the Company should have pursued these opportunities long ago, and it was imprudent for them to not have secured these low-cost resources already. A new program should only produce load reductions that were not achieved at previously funded avoided cost levels.

The PSE figures appear to assume that only a fraction of the load reduction – that requiring an investment in conservation technology -- involved any sort of cost. This appears to reflect an assumption that customer curtailment and customer fuel switching is cost-free. As a simple example, assume that a customer "curtailed" by using cold water instead of warm water for laundry. The expected result of this change is slightly less sparkling white whites, and slightly less brilliant colors coming out of the wash. To assign zero cost to this customer sacrifice is to imply that cleaner clothes do not now (and never did) have any value. We believe it is more reasonable to assume that customers became more sensitive to power costs and prices, and made a judgment that a compromise in laundry results was a fair trade-off. The Public Counsel assumption assumes that this sacrifice carried a cost of about half of the retail rate. This recognizes that customers saved about $.06/kwh on their electric bill by not consuming a kilowatt-hour, and then assigns half of this, or $.03/kWh, to the "cost" in the form of lower quality laundry results, and the other half is a net savings to the customer and shows up as a net benefit in the TRC calculation.

Simply because the cost of this type of sacrifice cannot be measured with precision is not a basis to ignore it. Absent other analytical results, choosing a midpoint between zero (the presumed out-of-pocket cost) and $.06/kwh (the average savings on the electric bill) is the best estimate of the customer sacrifice represented by curtailment. Staff's assumption of $.015/kWh and PSE's assumption of $.006/kWh are 25% and 10%, respectively, of the cost. A midpoint is a better assumption of the cost of curtailment.

Conservation and fuel switching are more easily quantified. The cost of these alternatives is discussed above in Section 3. The average cost of programmatic conservation and the average cost of wood and/or natural gas is very close to $.03/kWh, the assumption included in the Public Counsel base scenario. The assumption in the Public Counsel base scenario, of $.03/kWh in load reduction costs, is more appropriate than those used in the base scenarios prepared by Staff and PSE.

Washington Department of Community, Trade and Economic Development Energy Policy

Cost to Achieve Load Reductions: CTED Energy Policy is focusing its comments on the results of the cost effectiveness as it relates specifically to the costs of load reductions. We recognize that this variable influences the outcome of the cost-effectiveness analysis and we strongly disagree with the cost inputs that the Company and Commission staff used to achieve load reduction. Our comments here do not indicate an agreement that time-of-use program participants experienced a one percent electrical load reduction.

We agree with Public Counsel's input that $.03/kWh is an approximate and possibly conservative cost for achieving the proposed 1% load reduction due to some mix of installation of energy efficiency measures, curtailment of electricity use, or fuel switching.

The analysis of this program includes an assumption that the program participants, on average, achieved 1% load reduction and that this 1% load reduction endures for ten years. The standard practice for assessing cost-effectiveness of demand management programs indicates that in order to achieve ten years of savings a customer would either have to install hardwire measures in their home (more than once during the ten year period in the case of light bulbs) or be subject to an on-going education, training and maintenance effort. Both cost money. As one point of reference, the region's Northwest Energy Efficiency Alliance funded a program called Builder Operator Certification. This certification program requires many hours (days over the course of several months) of targeted training on how to maintain and operate commercial buildings to run efficiently and has a certification process at the conclusion of the required courses. The cost-effectiveness analysis of this program, which has a continuing education requirement after completion of the course, includes an assumption that the savings from this training intensive program endure for 5 years. That is five years with a continuing education requirement.

However, the Company and WUTC staff have both assumed that up to two-thirds of the savings for this program endure for ten years at no cost – no efficiency program cost, no time-of-use or efficiency educational campaign cost, no consumer cost, no hardship cost, no cost. We believe this is an unreasonable assumption and are unaware of a comparable assumption in the analysis of demand management programs.

The analyses by the Company and the WUTC staff both reflect low costs for actual energy efficiency measures installed by consumers. In particular, the Company's analysis of costs for savings due to energy efficiency alone is based on using $.021/kWh as an average levelized cost of energy efficiency measures for the residential class. This includes two very affordable measures – compact fluorescent bulbs and fixtures and one higher cost measure – low-income weatherization. It is worth noting that the Company was not implementing residential programs for either of these very low-cost hard-wired energy efficiency measures in 2001, during the drought and implementation of the time-of-use program.

This analysis should either indicate zero load reduction or should assign representative costs for the load reductions that have been estimated.

<u>Puget Sound Energy</u>

Puget Sound Energy wanted to use the Cost Effectiveness cases and scenarios to provide the Commissioners with an understanding of the conditions under which a mandatory residential TOU pricing program with mild price signals would be cost effective. To achieve that end, Puget Sound Energy created a future period scenario, with several sensitivities on various inputs and combination of inputs to determine at what point does the mandatory residential program become cost effective with the Total Resource Cost test (further details on these scenarios are contained in Appendix 4). The base future period scenario starts with a negative net Total Resource cost.

In future period sensitivity #1, the program costs have to decrease from $1.05 per month per customer to only $0.92 per month per customer in order for the program to become Cost Effective for the Total Resource Cost test.

In future period sensitivity #2, the transmission and distribution avoided costs have to increase from $35.32 per kW per year to only $45.60 per kW per year in order for the program to become Cost Effective for the Total Resource Cost test. While avoided T & D costs for the entire electric system may never reach this higher avoided cost, there may be places on the PSE distribution system that do. Therefore this result also gives us indications that there may be geographical specific places on the electric system where a time-of-use program would be cost effective.

In future period sensitivity #3, the peak period marginal cost of market energy prices would have to increase by only 16% in order for the program to become Cost Effective for the Total Resource Cost test. This relatively modest increase in peak-period market energy prices that may occur in the future, would be enough to make the time-of-use program cost effective.

In future period sensitivity #4, the residential price elasticities were increased by 27%. This is not an increase in the time-of-use rate differential itself, it is an increase in the customer response. This might be a potential result of the customers over time, as a group, responding more to monthly price signal they see on their monthly bill over a ten-year period. It is reasonable that there could be an increase in residential response for a long-run program. The increase in the customer response of 27% results in the program becoming Cost Effective for the Total Resource Cost test.

The future period sensitivity #5 is a combination of sensitivity #1 and sensitivity #3. That is to say that both the program costs can decrease and the marginal cost of energy in the peak period can increase in order for the time-of-use program to become cost effective. The program costs have to decrease from $1.05 per month per customer to $1.00 per month per customer, and the peak period marginal cost of market energy prices have to increase by a modest 10% in order for the program to become Cost Effective for the Total Resource Cost test.

The future period sensitivity #6 is a combination of sensitivity #1 and sensitivity #2. That is to say that both the program costs can decrease and the avoided transmission and distribution costs are higher in order for the time-of-use program to become cost effective. The program costs have to decrease from $1.05 per month per customer to $1.00 per month per customer, and the avoided transmission and distribution costs increased to $42.5 kW-year in order for the program to become Cost Effective for the Total Resource Cost test.

In future period sensitivity #7, the program costs have been modeled to show the difference of whether participating customers alone paid for the incremental costs or not. Overall the TRC test is generally the same as the future period scenario, but the Participant Test and the RIM tests change in terms of net benefits. With this slight modification to the program the time-of-use rates become cost effective at program costs of $0.925 per customer per month.

Cost to achieve load reduction and install energy efficient devices:

Puget Sound Energy selected an estimate of cost to achieve load reduction and conservation based on some real results from our actual residential customers on the time-of-use pilot, historic conservation program experience, and sound economic principles. PSE based its load reduction costs on measure cost data (excluding administrative and other non-measure program costs) from its residential compact fluorescent program – as proxy for low cost measures – and the Low Income Weatherization program – as proxy for high cost measures.

Other parties agree that the conservation measures for cost estimates selected by Puget Sound Energy are cheaper and easier measures for customers to install. That is why we believe that they are reasonable to use as estimates for what actual TOU customers would implement. Clearly not all customers will install energy efficiency measures in order to achieve their load reduction, that is why Puget Sound Energy used results from the customer survey. Survey results presented in PSE's October 30, 2001 report to the WUTC on the TOU pricing pilot indicate that many customers were able to reduce their load without installing energy efficiency products. In those instances where customers did install energy-efficient products, the survey indicated that most customers installed low cost items, such as compact fluorescent bulbs. In the survey of customers on time-of-use rates, about 10% stated that they installed energy efficiency devices. In the spirit of collaboration for this study, Puget Sound Energy tripled the amount of customers who said they installed energy efficiency products.

Puget Sound Energy believes the load reduction and conservation effects are sustainable over time, because the customer is continuously being sent and price signal and is getting highly detailed electric load information in their bill every month. We believe that the price signal and bill information that is sent to the customer every month is a highly effective tool for the continuing education requirement necessary to have sustaining conservation and load reduction.

The consumer's willingness to pay for electricity is fully captured by the demand curve for electricity, because the curve shows the maximum amount the consumer will pay for various quantities of electricity. This maximum amount captures both the tangible and the intangible attributes of electricity. The empirical results from the Brattle Group study have allowed us to develop estimates of the price elasticity of demand for electricity, and have allowed us to infer the underlying demand curve of electricity. There is no further need to estimate any intangible benefits or costs associated with electric usage. That would amount to double counting. For the purposes of estimating a cost to achieve load reduction, Puget Sound Energy chose to rely on economic principles and made every effort to avoid double counting the impacts. Even if one chose to ignore that double counting problem, it is important to note that not all "curtailment" results in sacrifice of comfort, convenience, or other benefits by consumers (i.e. turning off the unused baseboard heater in the basement *or light* in the back bedroom). There may be both non-energy sacrifices *and rewards* that accrue to participants (i.e. the intrinsic satisfaction of "doing the right thing", like recycling). Such non-energy costs and benefits are often intangible in nature and are virtually impossible to measure with any accuracy. Any attempts to quantify such factors for the TOU pilot would be based solely on arbitrary assumptions rather than any empirical data.

5. Discussion of Experiment Design

WUTC Staff

As was noted in the February 3, 2003 Milestone Document, Staff believes that cost-effectiveness results for this program need to be qualified by concerns about program design. The TOU pilot was implemented as an emergency response to the West Coast energy crisis in 2001. As a result of this hastened implementation, a statistically representative control group was not established. Ideally, a pilot would have included a statistical analysis that would account for major differences between the test group and a control group, such as age, income, family size, housing type, and energy usage. This type of statistical analysis was only performed, to a limited extent, between the TOU rate group and the TOU information only participants. Pilot findings would have been enhanced by inclusion of a representative non-TOU information control group as well as before and after measurements of pilot participants and the control group.

Public Counsel

Public Counsel agrees with the concern raised by Staff. We are particularly concerned about the effect of the power crisis, coupled with demographic differences among participants, on the program results. The power crisis was newsworthy, with everyone from the Governor on down urging restraint in the use of power. The demographic issue is of greater concern in many ways; the program meters were not installed randomly, but rather only in areas where cellular meter reading was feasible. Rural areas were omitted. Given the lower income and education levels of rural areas, it would be reasonable to expect different responses than in the urban/suburban areas where the program operated. We would be very circumspect about attempting to apply the results of the Pilot to an assumed system-wide rollout of 900,000 participants.

The results of the program were radically different among housing types, with multi-family and mobile home residents actually significantly increasing their usage of electricity, while single family customers usage declined. Again, there are demographic differences between these groups that raise questions about the applicability of the results among 300,000 customers to a wider potential program base.

Finally, the original program had a TOU rate differential that was three times the expected TOU market price differential. The revised program more closely reflected current assumptions with respect to marginal generation, transmission, and distribution costs. The projected load shifts in the base analyses were based on the measurement by Brattle. These were prepared primarily during the period prior to July 1, 2002, when the original (higher) TOU rate differentials were in place. With a lower rate differential based on cost, presumably the price response of customers would be moderated somewhat. The price response of the pilot period has been applied on a going forward basis, without consideration of the lower cost-based price differential reflected in the settlement stipulation and post-July 1, 2002 rates. This may tend to overstate the effect that should be expected from a long-term program.

It is noteworthy that, despite the differences we have with the assumptions of other parties and the concern we have about the integrity of the pilot program data, that the analyses show that the program is not cost-effective. Even those base scenarios using the assumptions we are concerned about produce results that the program as designed was not cost-effective and was not expected to become cost-effective.

Puget Sound Energy

The load impacts of the TOU Pricing Pilot were the subject of an econometric/statistical analysis of billing data from June 2001, the inception of the TOU pilot, until August 2002. This analysis was conducted for the Company by the Brattle Group and reviewed and discussed extensively by the Collaborative. The cost-effectiveness analysis utilized results from June 2001 – June 2002, when the pilot as originally designed was in effect.

TOU rates affect customer energy use in two ways:
- Load shifting – moving energy consumption from peak to off-peak time periods.
- Load reduction – reducing overall energy consumption.

The load *shift* analysis statistically compared actual consumption of each time block under the TOU pricing program with a modeled estimate of what consumption would have been if the program participants continued to be charged the current flat rate.

The modeled estimate of what consumption would have been in the absence of the program was based on actual TOU usage patterns for a comparison group of residential customers who remained on the Personal Energy Management TOU information-only (IO) program. A second comparison group was also considered. This group was composed of customers with AMR meters who have participated in neither the TOU pricing pilot nor the information-only program, and for whom TOU information was collected. However, this second comparison group was not as comparable to the TOU treatment group as the IO group. Therefore, analyses using this group were not successful. The analysis accounts for differences in housing type, electric/gas end uses (through a rate schedule designation), whether a customer is on budget billing (which may affect response to TOU pricing), and pre-program energy use (as a proxy for demographic and other non-program differences between the TOU and comparison groups). The results showed an overall average peak period load shift for residential program participants of 5% per month, which remained very steady from the beginning of the analysis period to the end.

This analytical approach was selected to fit the overall intent and design of the pilot program. The TOU pilot was intended to test customer response and achieve meaningful load impacts from a large-scale residential TOU pricing program. The pilot was never intended to be small-scale, controlled scientific experiment, nor was it intended to be implemented for sub-classes of residential customers. This general program implementation goal precluded development of a tightly defined "pure" control group of customers who were similar to program participants except for participation in any kind of TOU rate or information program. However, a statistically valid control group of customers who received information about their TOU usage, but were never charged the TOU rate, was available. This control group was very similar to the TOU pilot participants in terms of energy use and location. The two groups were analyzed by sub-group, such as housing type (i.e., single-family TOU versus single-family information-only group), so that differences in the mix of housing types and heating fuels was controlled for in the analysis. The results of the sub-group analysis were weighted and aggregated up to an overall average effect for residential TOU customers in general.

Econometric comparison of the TOU participants to the control group who received information only yielded statistically robust results that clearly show TOU pricing participants shifted loads away from peak pricing periods. It seems intuitively logical that the magnitude of this impact would be larger if TOU pricing participants had been compared to a control group of "pure" non-participants, although this effect was not directly measured.

Load *reduction* (conservation) effects were measured as the difference between overall electricity consumption in the current month and electricity consumption in the same month of the previous year. The analysis makes adjustments for weather. All analysis was based on average daily consumption, to account for any differences in customer billing cycle lengths. Conservation effects are calculated for three groups: (1) TOU pricing customers, (2) TOU information-only (IO) customers, and (3) all other residential customers, i.e., customers not receiving TOU usage information. Comparisons between these groups are somewhat suggestive, because, although the first two groups are basically similar to each other, we do not know how comparable the third group is to the first two in terms of determinants of energy use other than receiving TOU information. This analysis shows that, in general, TOU pricing participants used less energy on a percentage basis than the other two groups, with TOU pricing participants saving an average of 1% of their total energy use per month compared to customers who were not exposed to TOU price signals or information. The difference between TOU pricing participants and those who received TOU information only was much smaller, averaging 0.3% per month.

The drought in the Pacific Northwest, the declaration of the state of emergency by the Governor and the energy crisis in the West may have contributed to a heightened awareness of energy use by customers, which has raised some concerns about biased results. However, these effects are held constant in the analysis because all customers were exposed to the publicity surrounding these issues, not just the TOU participants. In addition, customer survey results, submitted to the WUTC as part of the Company's October 30, 2001 TOU pilot report, show that the energy crisis was fading as a top-of-mind issue with consumers as early as July 2001, yet the load impacts remained relatively constant a year later in the summer of 2002. It seems clear that TOU customers shifted and reduced their energy use, and for reasons other than weather or widespread general awareness of an "energy crisis".

6. Discussion of Other PSE Pricing/Demand Response Programs

In the collaborative's May 1, 2003, report on preliminary findings, the parties noted that this final report would identify opportunities to use the lessons learned from other demand response programs carried out by Puget Sound Energy (PSE) and other utilities. First, PSE has implemented a number of innovative demand response and pricing techniques in recent years, of which the TOU Pilot Program was one. The different programs have included:

a) Optional Large Power Sales Rate -- Schedule 48, [1996 – 2001]
b) Retail Wheeling Pilot Program, [1997-1999]
c) Conservation Incentive Credit for all customers, [2001]
d) Voluntary Load Curtailment program – Schedule 93 for larger customers, [Beginning 2000, tariff still in effect]

e) Time-of-Use Pricing for Residential Consumers, [2001-2002]
f) Time-of-Use Pricing for Secondary General Service Customers, [2001-2002]
g) Home Comfort Control Pilot, [2000]

During the drought of 2000-2001, Puget implemented programs (c), (d), (e), (f) and (g) above. These were short-term programs implemented in the context of the drought and high market prices to achieve demand response from residential and non-residential consumers. The Conservation Incentive Credit and Schedule 93 together saved a total of 488,283 megawatt-hours (MWh) at an average cost of $38.85/mWh, which was significantly lower than the average market price during the power crisis period when these programs were initiated.

Although, in the Final Evaluation Report to the WUTC (on the CIC Program), the Company reported that using either Staff's or PSE's analysis, there were no positive net monetary benefits to the Company, these two programs remain viable options for dealing with future wholesale price instability. The Voluntary Load Curtailment program for large customers remains effective in the tariff and available to the Company if market prices sharply increase again. The Conservation Incentive Credit program is a useful "on-the-shelf" program that could be utilized again in some form, if conditions warrant.

The other PSE programs may have less applicability in the future for dealing with wholesale price instability. The Schedule 48 daily index pricing program for large volume customers worked well until the drought of 2000-2001, but then became unsustainable for the businesses that had not hedged their electricity purchases. During the period of extremely high market prices in late 2001, many Schedule 48 customers responded by reducing or curtailing production and associated electricity consumption, and others operated on-site generating resources within applicable environmental limitations. However, Schedule 48 has not been formally evaluated with respect to its effectiveness as a demand response program, but was cancelled for other reasons. The tariff was terminated as part of the settlement stipulation in Docket UE-001952 (Air Liquide).

The retail wheeling pilot program, encouraged by the Commission in its approval of the merger of Puget Sound Power & Light and Washington Natural Gas, did not provide an insight into retail wheeling for residential consumers when no vendors entered the marketplace. Several commercial and industrial customers participated in the pilot over its two-year term.

The Brattle Group's analysis of non-residential customers on the TOU rate program did not yield any statistically significant results. The time-of-use program for non-residential customers was allowed to expire at the end of the designated pilot program time period. Agreement was not reached on continuation of the TOU program for these customers in the PSE general rate proceeding (Docket UE-011570).

The Home Comfort Control Pilot was operated from February through April 2000 by Puget Sound Energy (PSE), in partnership with Schlumberger/CellNet, Carrier Electronics, and Silicon Energy. This was a field test of real-time residential load management in 105 Kent, Washington volunteer households. State-of-the-art software and control technology installed in each participating home permitted PSE to initiate and confirm thermostat-based curtailment signals to gas and electric residential furnaces. Participants received curtailment event messages on their thermostat screens and could override any event at the press of a button. Participants could also access their thermostats over the Internet, to read and reset them. PSE initiated 41 curtailment events, setting back the participants' thermostats by 2º F or 4º F for two hours, across a range of morning, mid-day, and evening peak demand time slots. When statistically measured against a control group of Kent households, load impact analysis indicated load reductions for both electric and gas heat, across events and in all time slots. Overrides were concentrated among a few participants. No volunteers dropped out during the program.

Discussion of Other Pricing/Demand Response Programs

In addition to the demand response programs PSE has implemented, there are several variations of pricing and payment options that could be considered. The TOU Collaborative has looked at a few specific options that might be utilized on the PSE system. These include:

h) Time-of-Use Pricing for Larger Commercial Customers
i) Critical Peak Pricing for Residential Customers
j) Critical Peak Pricing for Commercial / Industrial Customers
k) Extreme Day Pricing

Critical Period/Critical Peak Pricing

The Collaborative is interested in the possible results that may be reached under critical period/critical peak pricing. Critical Period/Critical Peak Pricing products have similar characteristics to standard time-of-use products, with the difference being, on several days (10 to 15 days) of the year, during the highest cost hours, customers pay a higher energy charge. As with the price variation on time-of-use time periods, the prices during those "critical period" hours would be known to the customer in advance, the prices would be in the tariffs, and would not change over the short- term. Customers would be notified of those critical period/critical peak days at least one day before. Customers would know the cost of electricity during the next day's critical period/critical peak, thus they could make the appropriate decision to reduce their electric load in response to the known price signal. By being limited to a finite number of days (10 to 15 days) for a critical peak period, customers have an increased ability to plan and respond to this price signal. The "critical period/critical peak" prices would be expected to be two to six times higher than typical prices, designed to achieve significant short-term load shedding and/or load shifting during the period when they are in effect, which could be on a hourly or daily basis.

Experiments by other utilities, notably Gulf Power, have indicated that such rates, when coupled with automated response networks installed in the home or business (that automatically shut off discretionary loads during periods of high prices) can achieve significant consumer and system savings, and achieve high levels of consumer satisfaction.

We are aware, however, that Puget's residential peak demands occur during the winter months, while the west coast power systems price spikes are most likely to occur during the afternoon period of hot summer days, driven by air-conditioning loads in areas outside of Western Washington. This may reduce the economic value of critical period/critical peak pricing in the PSE system, and it will require additional research, analysis, and possible pilot-testing to determine if such critical period/critical peak pricing can produce satisfactory results if applied to PSE residential consumers.

For larger-use commercial and industrial customers, there may be lower costs relative to energy impacts, less need for automated response systems, larger potential response, and greater coincidence of customer peak demand with system peak prices. We are more optimistic that the economics of critical peak pricing will be favorable for such customers, but do not necessarily have the same optimism for the level of customer satisfaction with such rates that might be experienced. Research, analysis, and pilot-testing may demonstrate the desirability or non-desirability of such options for these customers.

Extreme Day Pricing

This product is similar to the Critical Peak Pricing product, but it has a rate design that is reflective of typical prices during nearly all hours of the year, but shifts to a more real-time nature when short-term market prices greatly exceed typical prices. The "non-extreme day" prices would be determined by the Commission through the normal ratemaking process and would be the default rates charged during non-extreme days.

The "extreme day" prices would be expected to be two to six times higher than typical prices, designed to achieve significant short-term load shedding and/or load shifting during the days that have extreme market prices, which could be on a hourly or daily basis. Extreme day events would be limited to several days (10 to 15 days) of the year. Customers would be notified of those extreme days at least one day before. Customers would know the cost of electricity during the next day's peak time period, thus they could make the appropriate decision to reduce their electric load in response to the known price signal.

For larger-use commercial and industrial customers, there may be lower costs relative to energy impacts, less need for automated response systems, larger potential response, and greater coincidence of customer peak demand with system peak prices. We are more optimistic that the economics of extreme day pricing will be favorable for such customers, but do not necessarily have the same optimism for the level of customer satisfaction with such rates that might be experienced. Research, analysis, and pilot-testing may demonstrate the desirability or non-desirability of such options for these customers.

Conclusion

At this time, the Collaborative does not recommend that a formal process or timeline be established to review these options. We believe that examining these options in the context of on-going Least Cost Plan (LCP) development is the appropriate forum to assess opportunities for different types of demand-response programs.

To this end, PSE has begun a resource-planning evaluation of peak demand response that is intended to be incorporated in the August 31 LCP Update. This evaluation is focusing on 1) demand-side capacity that could help meet cold weather events that affect temperature-dependent PSE customer loads, and 2) infrequent events (e.g., in range from 23°F down to 16°F). The evaluation efforts, in conjunction with the LCP Advisory Group (LCPAG), will include a consideration of other utilities' experiences with demand-response programs that target temperature-driven peak capacity needs, a preliminary assessment of some alternatives and potential peak reductions, and a PSE portfolio analysis of net savings potential from peak demand response.

Appendix 1

SUMMARY - Base Case Scenarios	Puget Sound Energy	Public Counsel	WUTC Staff
Inflation Rate	2.75%	2.75%	2.75%
Discount Rate	7.30%	7.30%	7.30%
Line Loss	7.40%	7.40%	7.40%
Reserve Margin	15.00%	15.00%	15.00%
Planning Horizon	10 Yrs	10 Yrs	10 Yrs
Customer Participation	900K	300>200>30K	300K
Load Reduction	1% total	1% total	1% total
Cost to Achieve Load Reduction	0.006/kWh	0.03/kWh	0.015/kWh
Environmental Adder (all periods)	$.005/kWh	$.005/kWh	$.005/kWh
Environmental Adder (Economy period)		$.005/kWh	
Elasticity Factor	CRA	Calib to neutral	CRA
Marginal Generation CapacityCosts	0	0	0
Marginal T&D costs	$35.32/year	$35.32/year, w/5yr phase-in	$35.32/year, w/5yr phase-in
Incremental Meter Read and PEM Cost	$1.05	$1.05	$1.05
Base Price (rates)	Rates from GRC	Rates from GRC	Rates from GRC
Coincident Factor	CRA	CRA	CRA

TABLE 1 – Inputs to CRA Cost-Effectiveness Model

Input	Description
Inflation Rate	Used to adjust prices or costs from 1st year input. Parties using 2.75%. This factor can be applied to individual inputs.
Discount Rate	Used to measure present value of the streams of costs and benefits. Parties are using PSE's weighted cost of capital: 8.75% before-tax or 7.3% after-tax.
Line Losses	Accounts for differences between customer meter and generator bus bar resulting from T&D line losses. Inputs have been either on a system average or customer class basis.
Planning Horizon	Number of years over which to perform analysis. Initial case runs are 10 years.
Customer Participation	Number of customers assumed to be enrolled in the program, which can vary by year. Sensitivities are being performed.
Customer Elasticities and Usage	Usage is derived from Brattle Group data collection. Price elasticities (own, cross and complementary) are calibrated by CRA to be consistent with Brattle Group analysis and literature review, calculated by season. Elasticities result in shifts in TOU load and changes in total load. Sensitivities are being performed on inputs.
Incremental Load Reduction Savings	Average amount of incremental load reduction achieved by program participants, exogenous to elasticities. Sensitivities are being performed.
Marginal Generation Costs	Values can be input as a $ per kWh--identifying year, season, and time-of-day differences. Costs can also be input on a $ per kW basis, which can also be different by year. Parties agreed to use the output of the Aurora production cost model, as discussed below.
Marginal Transmission and Distribution Capacity Costs	Value of T&D capacity additions avoided. Parties agreed to use long-run value of $35.32/kW-year, as discussed below. Sensitivities are being performed on the timeframe to achieve this long-run value.
Costs to Achieve Load Reduction	Additional cost to TOU participants to achieve the total load reduction. Sensitivities are being performed.
Environmental Adder	Recognizes benefits (or costs) of reducing (or increasing) environmental externalities. Environmental impacts can be input on a kWh or percentage basis. Input amounts can be run on all load shifts and/or on individual TOU periods (i.e., economy period). Sensitivities are being performed.
Utility Program Costs	Program costs include metering, billing, website, marketing and administration. Cost can be input on a per participant or fixed $ basis. Sensitivities are being performed on input.
Retail Energy Rates	TOU retail rates. Inputs can show the variance of general rate levels and/or price differentials.

Appendix 2

CHARLES RIVER ASSOCIATES

MEMORANDUM

To: Eric Englert

From: Ahmad Faruqui and Joanna Burleson

Date: April 23, 2003

Subject: **WUTC STAFF SCENARIO RESULTS**

We have run the updated WUTC Staff Scenario. This memorandum briefly describes the key assumptions and results.

Price Effects

Our cost-effectiveness model (CEM) has been calibrated to produce the load impacts that the Brattle Group had measured. The calibration was performed on a seasonal basis. Using the prices that prevailed during the time of the pilot, in conjunction with customer usage data from the pilot population, CEM predicts that annual usage would drop by –0.28%, which is very close to the percentage drop estimated by Brattle.

There are three drivers of load impacts within CEM: price elasticities, price changes, and but-for usage values. Any modification to these inputs will result in a change in the load impacts. For the Staff Scenario, we developed a set of TOU prices using the July rate level while maintaining the April price differentials. As a result, we would expect to find that the load impacts for this scenario would vary from the –0.28% drop that prevailed during the pilot. That is indeed the case, and we find that the impact is –0.313%. Staff requested that incremental conservation savings be set equal to 1%, less what is embedded in the price elasticities. To obtain a net impact of –1%, we therefore estimated and applied a conservation factor -0.687%.

Results

Table 1 contains the results for the new Staff scenario. Table 2 contains the year-by-year results on the TRC test for the revised base scenario.

Base Scenario Assumptions

The Staff Base Scenario has a 7.30% discount rate and 7.4% line losses rate. Load reduction costs are $0.015/kWh, escalated at the rate of inflation. An environmental adder of 5 mils/kWh is applied to all pricing periods and also escalated at the inflation rate. MCT&D ramps up over 5 years to $35.32 and incremental meter reading costs are $1.053/customer/month. Program participation is constant at 300,000 a year.

Compared to the previous staff base scenario, the participant test net benefits increased by approximately $2.5 million. This is due to the drop in load reduction costs by half and the reduced discount rate. The TRC test net benefits fell by about $0.5 million, a combined effect of a change to the discount rate, a slower ramping up of avoided T&D costs, and the drop in load reduction costs. The RIM test net benefits fell by $3.14 million, reflecting the new ramp up of avoided T&D costs over a five-year period and change in the discount rate. Finally, the PAC test net benefits were reduced by about $2 million, also due to slower ramping up of avoided T&D cost structure and the lower discount rate.

The results of the Staff scenario indicate that the program is not worth doing, since it does not pass the TRC test. It fails the participant test by an even bigger amount. Non-participants are made better off by the program, since the RIM test is positive. The PAC test is the most positive, indicating that the program will improve the utility's bottom line.

Table 1: Comparison CEM Results

	(Millions)	Participant Test	TRC Test	RIM Test	PAC Test
Commission Staff Base Scenario (04/23/03)	Benefits	$15.53	$22.51	$21.09	$21.09
	Costs	$33.12	$33.12	$15.53	$0.00
	Net Benefits	-$17.59	-$10.60	$5.56	$21.09
Commission Staff Base Scenario (01/14/03)	Benefits	$14.54	$24.57	$23.24	$23.24
	Costs	$34.65	$34.65	$14.54	$0.00
	Net Benefits	-$20.11	-$10.08	$8.70	$23.24

TOTAL RESOURCE COST (TRC) TEST		10 Year Projection	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Benefits (NPV)												
Benefits (per participant)												
Avoided Energy Costs (monthly)		**$50.64**	$5.65	$5.23	$5.21	$5.13	$4.86	$4.99	$4.90	$5.01	$4.97	$4.69
Avoided Capacity Costs		**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided T&D Costs		**$24.41**	$0.91	$1.65	$2.29	$2.84	$3.30	$3.07	$2.87	$2.67	$2.49	$2.32
Total Benefits		**$75.05**	$6.56	$6.89	$7.50	$7.97	$8.16	$8.06	$7.76	$7.68	$7.46	$7.01
Total Benefits for All Customers	(millions)	**$22.51**	$1.97	$2.07	$2.25	$2.39	$2.45	$2.42	$2.33	$2.30	$2.24	$2.10
Costs (NPV)												
Customer Costs												
Total Load Reduction Costs for All Customers	(millions)	**$3.98**	$0.48	$0.46	$0.44	$0.42	$0.40	$0.39	$0.37	$0.35	$0.34	$0.32
Total Startup Costs for all Customers	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total On-Going Costs for all Customers	(millions)	**$29.14**	$3.61	$3.43	$3.27	$3.11	$2.96	$2.81	$2.68	$2.55	$2.42	$2.31
Utility Costs												
Total Program Startup Costs	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total On-Going Program Costs for all Customers	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total New Customer Specific Costs for all Customers	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total All Participant Customer Specific Costs for all Customers	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Costs for All Customers	(millions)	**$33.12**	$4.09	$3.89	$3.71	$3.53	$3.36	$3.20	$3.05	$2.90	$2.76	$2.63
Total Costs less Fees and Customer Incentives	(millions)	**$33.12**	$4.09	$3.89	$3.71	$3.53	$3.36	$3.20	$3.05	$2.90	$2.76	$2.63
Total Number of Participants			300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Present Value Total Benefits	(millions)	**$22.51**	$1.97	$2.07	$2.25	$2.39	$2.45	$2.42	$2.33	$2.30	$2.24	$2.10
Present Value Total Costs	(millions)	**$33.12**	$4.09	$3.89	$3.71	$3.53	$3.36	$3.20	$3.05	$2.90	$2.76	$2.63
Present Value Net Benefits	(millions)	**-$10.60**	-$2.12	-$1.83	-$1.46	-$1.14	-$0.91	-$0.78	-$0.72	-$0.60	-$0.52	-$0.53

MEMORANDUM

To: Mert Lott

From: Ahmad Faruqui and Joanna Burleson

Date: January 14, 2003

Subject: **WUTC STAFF SCENARIO RESULTS**

We have run the WUTC Staff Scenario and associated sensitivities. This memorandum briefly describes the key assumptions and results.

Price Effects

Our cost-effectiveness model (CEM) has been calibrated to produce the load impacts that the Brattle Group had measured. The calibration was performed on a seasonal basis. Using the prices that prevailed during the time of the pilot, in conjunction with customer usage data from the pilot population, CEM predicts that annual usage would drop by –0.28%, which is very close to the percentage drop estimated by Brattle.

There are three drivers of load impacts within CEM: price elasticities, price changes, and but-for usage values. Any modification to these inputs will result in a change in the load impacts. For the Staff Scenario, we developed a set of TOU prices using the July rate level while maintaining the April price differentials. As a result, we would expect to find that the load impacts for this scenario would vary from the –0.28% drop that prevailed during the pilot. That is indeed the case, and we find that the impact is –0.313%. Staff requested that incremental conservation savings be set equal to 1%, less what is embedded in the price elasticities. To obtain a net impact of –1%, we therefore estimated and applied a conservation factor -0.687%.

Results

Table 1 contains results for the Staff scenario and accompanying sensitivity runs. Table 2 contains the year-by-year results on the TRC test for the base scenario.

Base Scenario Assumptions

The Staff Base Scenario has an 8.76% discount rate and 7.4% line losses rate. Load reduction costs are $0.03/kWh, escalated at the rate of inflation. An environmental adder of 5 mils/kWh is applied to all pricing periods and also escalated at the inflation rate. MCT&D is set to $35.32 and incremental meter reading costs are $1.053/customer/month. Program participation is constant at 300,000 a year.

Sensitivities

Sensitivity 1 sets the discount rate to 7%. In sensitivity 2, the load reduction costs are lowered to $0.02/kWh. Sensitivities 3 and 4 eliminate the environmental adder and set it equal to 5 mils applied to the economy period only, respectively. Sensitivity 5 ramps up the MCT&D over a five-year time period. Sensitivity 6 sets the incremental metering cost to $0.553/meter/month. Sensitivity 7 includes no incremental conservation beyond that contained in the price elasticities.

The various runs indicate that the TOU program is only cost-effective in one instance, and that is Scenario 6 where the incremental metering costs are lowered to $.535/meter/month.

Table 1: Preliminary CEM Results

	(Millions)	Participant Test	TRC Test	RIM Test	PAC Test
Commission Staff Base Scenario	Benefits	$14.54	$24.57	$23.24	$23.24
	Costs	$34.65	$34.65	$14.54	$0.00
	Net Benefits	-$20.11	-$10.08	$8.70	$23.24
Sensitivity 1: Discount Rate 7%	Benefits	$15.75	$26.76	$25.32	$25.32
	Costs	$37.63	$37.63	$15.75	$0.00
	Net Benefits	-$21.88	-$10.87	$9.57	$25.32
Sensitivity 2: Load Reduction Costs of $0.02	Benefits	$14.54	$24.57	$23.24	$23.24
	Costs	$32.17	$32.17	$14.54	$0.00
	Net Benefits	-$17.63	-$7.60	$8.70	$23.24
Sensitivity 3: Environmental Adder (0)	Benefits	$14.54	$23.24	$23.24	$23.24
	Costs	$34.65	$34.65	$14.54	$0.00
	Net Benefits	-$20.11	-$11.41	$8.70	$23.24
Sensitivity 4: Environmental Adder (5 mils economy period)	Benefits	$14.54	$20.41	$23.24	$23.24
	Costs	$34.65	$34.65	$14.54	$0.00
	Net Benefits	-$20.11	-$14.24	$8.70	$23.24
Sensitivity 5: Ramp up MCT&D	Benefits	$14.54	$20.90	$19.57	$19.57

	Costs	$34.65	$34.65	$14.54	$0.00
	Net Benefits	-$20.11	-$13.75	$5.03	$19.57
Sensitivity 6: Incremental Metering Costs ($0.553)	Benefits	$14.54	$24.57	$23.24	$23.24
	Costs	$8.80	$8.80	$14.54	$0.00
	Net Benefits	$5.75	$15.77	$8.70	$23.24
Sensitivity 7: No Incremental Conservation beyond elasticities.	Benefits	$4.77	-$3.50	$16.21	$16.21
	Costs	$29.55	$27.22	$29.55	$4.77
	Net Benefits	-$24.77	-$30.72	-$13.34	$11.43

JB/jb

TOTAL RESOURCE COST (TRC) TEST		10 Year Projection	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Benefits (NPV)												
Benefits (per participant)												
Avoided Energy Costs (monthly)		**$47.13**	$5.58	$5.09	$5.00	$4.86	$4.54	$4.60	$4.45	$4.50	$4.40	$4.09
Avoided Capacity Costs		**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided T&D Costs		**$34.78**	$4.43	$4.19	$3.96	$3.74	$3.53	$3.34	$3.15	$2.98	$2.81	$2.66
Total Benefits		**$81.91**	$10.01	$9.28	$8.95	$8.60	$8.07	$7.94	$7.61	$7.47	$7.22	$6.75
Total Benefits for All Customers	(millions)	**$24.57**	$3.00	$2.78	$2.69	$2.58	$2.42	$2.38	$2.28	$2.24	$2.17	$2.03
Costs (NPV)												
Customer Costs												
Total Load Reduction Costs for All Customers	(millions)	**$7.43**	$0.95	$0.89	$0.84	$0.80	$0.75	$0.71	$0.67	$0.64	$0.60	$0.57
Total Startup Costs for all Customers	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total On-Going Costs for all Customers	(millions)	**$27.22**	$3.56	$3.34	$3.14	$2.94	$2.76	$2.59	$2.44	$2.29	$2.15	$2.02
Utility Costs												
Total Program Startup Costs	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total On-Going Program Costs for all Customers	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total New Customer Specific Costs for all Customers	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total All Participant Customer Specific Costs for all Customers	(millions)	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Costs for All Customers	(millions)	**$34.65**	$4.51	$4.23	$3.98	$3.74	$3.52	$3.31	$3.11	$2.92	$2.75	$2.58
Total Costs less Fees and Customer Incentives	(millions)	**$34.65**	$4.51	$4.23	$3.98	$3.74	$3.52	$3.31	$3.11	$2.92	$2.75	$2.58
Total Number of Participants			300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Present Value Total Benefits	(millions)	**$24.57**	$3.00	$2.78	$2.69	$2.58	$2.42	$2.38	$2.28	$2.24	$2.17	$2.03
Present Value Total Costs	(millions)	**$34.65**	$4.51	$4.23	$3.98	$3.74	$3.52	$3.31	$3.11	$2.92	$2.75	$2.58
Present Value Net Benefits	(millions)	**-$10.08**	-$1.50	-$1.45	-$1.29	-$1.16	-$1.10	-$0.93	-$0.83	-$0.68	-$0.58	-$0.56

Appendix 3

CHARLES RIVER ASSOCIATES

MEMORANDUM

To: Jim Lazar

From: Ahmad Faruqui and Joanna Burleson

Date: April 28, 2003

Subject: **PUBLIC COUNSEL SCENARIO RESULTS**

We have completed our analysis of the updated Public Counsel Scenario. This memorandum summarizes our key assumptions and analysis results.

Price Effects

Our cost-effectiveness model (CEM) has been calibrated to produce the load impacts that the Brattle Group measured. This calibration was performed on a seasonal basis. Using the prices that prevailed during the time of the pilot, in conjunction with customer usage data from the pilot population, our model predicts that annual usage would drop by –0.28%, which is very close to the percentage drop estimated by Brattle.

There are three drivers of load impacts in CEM: price elasticities, price changes, and but-for usage values. Any modification to these inputs will result in a change in the load impacts. For the Public Counsel Scenario, we used the July prices. Since the prices have changed, we would expect to find that the load impacts for this scenario would vary from the –0.28% drop that prevailed during the pilot. That is indeed the case. Using the Brattle-calibrated elasticities and July prices, the scenario results in a –0.25% load change.

Public Counsel requested that the elasticities be calibrated to achieve neutral impact on load, and then to add a 1% exogenous load reduction factor, combining conservation, curtailment, and fuel switching into a single measure of load impact. Using the new July prices, we have recalibrated the elasticities by adjusting the own-price elasticity for the economy period until we obtained a zero percent annual load impact. Then we added a 1% load reduction factor. This guarantees that the net impact on load will be –1%.

Results

Table 1 contains results for the Public Counsel Scenario.

Base Scenario Assumptions

The updated Base Scenario has a 7.3% discount rate and 6.5% line losses rate. Load reduction costs are $0.03/kWh, not escalated at the rate of inflation. An environmental adder of 5 mills/kWh is applied to the economy period. MCT&D is set to $35.32, ramped up over a five-year period, and incremental meter reading costs are $1.05/customer/month. Program participation starts at 300,000 a year and ramps down to 30,000 by the fourth year of the program. The $1 million annual utility cost has been removed from the scenario.

The TRC net benefits are higher by about $13 million, due to a reduction in the environmental adder (previously applied to all periods), new ramp down of customer participation and 5-year ramp up of MCT&D, and elimination of the $1 million annual utility cost.

Table 1: CEM Results

	(Millions)	Participant Test	TRC Test	RIM Test	PAC Test
Public Counsel Base Scenario (01/10/03)	Benefits	$18.13	$24.69	$23.70	$23.70
	Costs	$36.10	$44.05	$26.08	$7.94
	Net Benefits	-$17.97	-$19.36	-$2.37	$15.76
Public Counsel Base Scenario (04/28/03)	Benefits	$5.79	$4.36	$5.11	$5.11
	Costs	$11.09	$11.09	$5.79	$0.00
	Net Benefits	-$5.30	-$6.73	-$0.68	$5.11

AF/jb

Appendix 4

MEMORANDUM

To: Eric Englert, Bill Hopkins and George Pohndorf, Puget Sound Energy **CRA No.** D03471-00

From: Ahmad Faruqui and Joanna Burleson

Date: April 25, 2003

Subject: **UTILITY SCENARIO RESULTS**

We have run two scenarios and several sensitivities with updated assumptions the Company provided us recently. The Future Period scenario deals with a ten-year period from 2003 to 2012 and envisions full-scale customer participation. The Historic Period scenario is limited to a single year, 2003, and based on the Mid-C energy prices for that year.

This memorandum briefly describes the key assumptions and results.

Price Effects

Our cost-effectiveness model (CEM) has been calibrated to produce the load impacts that the Brattle Group had measured. The calibration was performed on a seasonal basis. Using the prices that prevailed during the time of the pilot, in conjunction with customer usage data from the pilot population, CEM predicts that annual usage would drop by –0.28%, which is very close to the percentage drop estimated by Brattle.

There are three drivers of load impacts within CEM: price elasticities, price changes, and but-for usage values. Any modification to these inputs will result in a change in the load impacts. For both the Historic and Future Period Scenarios, the TOU prices applied used the July price level while retaining the April 2001 differentials. The impact is –0.313% and a conservation factor of –0.687% was applied to achieve net conservation of 1%.

Assumptions

Historic Period Scenario

The Historic Period Scenario has an inflation rate of 2.75%, a new discount rate of 7.30%, and a one-year planning horizon. Customer participation is now set constant at 300,000, up from 290,000. An environmental adder of 5 mils/kWh is applied to all periods, escalated at the rate of inflation. Marginal generation capacity costs are $0/kW-year and MCT&D avoided costs are $35.32/kW-year. There are Utility Program costs of $1.26/customer/month, down from $1.40 in the previous scenario. The participant conservation cost is now 0.6¢/kWh, previously 0.2¢/kWh. Usage is based on the profile of the average pilot participant.

Future Period Scenario

The Future Period Scenario has an inflation rate of 2.75%, a lower discount rate of 7.30%, and a 10-year planning horizon. Customer participation is set constant at 900,000. An environmental adder of 5 mils/kWh is applied to all periods, escalated at the rate of inflation. Marginal generation capacity costs are $0/kW-year and MCT&D avoided costs are $35.32/kW-year. Utility Program costs are $1.05/customer/month. The participant conservation cost is now 0.6¢/kWh, previously 0.2¢/kWh. Usage is based upon the profile of an average PSE customer.

Future Period Sensitivities

Seven sensitivities were run on the Future Period Scenario. In sensitivities 1 through 6, a single input assumption was calibrated to achieve a slightly net positive TRC value in order to determine the break-even point at which this mandatory program is cost-effective. Sensitivity 1 reduces Utility Program costs to $0.92/customer/month, by 12.4%, resulting in a TRC net value of $0.60 million. Sensitivity 2 raises MCT&D avoided costs by 32%, to $46.50/kW-year. Sensitivity 3 increases avoided energy prices by 16% for the peak period and sensitivity 4 scales up all price elasticities by 27%. Sensitivity 5 combines Sensitivities 1 and 3, reducing Utility Program costs by 5%, to $1.00/customer/month and increasing peak period avoided energy prices by 10%. Sensitivity 6 combines Sensitivities 1 and 2, reducing Utility Program costs by 5%, to $1.00/customer/month and raising MCT&D avoided costs by 20% to $42.50/kW-year. Sensitivity 7 assumes that Utility Program costs are not paid by the participating customers, but rather are borne by the Utility. This value of $0.925 was calibrated to determine the break-even point for the PAC test.

The results of the sensitivities are detailed in Table 2.

Results

Tables 1 and 2 contain the results for the Utility Scenarios and Sensitivities. The program does not pass the TRC test for either the Historic or Future Period Scenarios. It is marginal for the Historic Period Scenario, but since that analysis is limited to a single year, it is not directly comparable to the other scenario.

Compared to the earlier results for the Historic Period scenario, the net TRC benefits fell by about $0.9 million. This is due to the drop in discount rate and the increase in the participant conservation cost. For the Future Period scenario, the net TRC benefits fell approximately $3 million from the previous run. This can be attributed also to the change in discount rate and customer conservation costs.

The break-even analysis involved in the seven sensitivity cases suggests that the program has the potential for becoming cost-effective under a wide range of conditions.

Table 1: Base Scenario CEM Results

	(Millions)	Participant Test	TRC Test	RIM Test	PAC Test
Historic Period Scenario	Benefits	$2.09	$2.73	$2.56	$2.56
	Costs	$4.50	$4.50	$2.09	$0.00
	Net Benefits	-$2.41	-$1.78	$0.47	$2.56
Future Period Scenario	Benefits	$80.84	$81.09	$76.87	$76.87
	Costs	$91.28	$91.28	$80.84	$0.00
	Net Benefits	-$10.44	-$10.19	-$3.96	$76.87

Table 2: Sensitivity Results

	(Millions)	Participant Test	TRC Test	RIM Test	PAC Test
Future Period Sensitivity 1 (Program Costs $0.92/cust./mo.)	Benefits	$80.84	$81.09	$76.87	$76.87
	Costs	$80.49	$80.49	$80.84	$0.00
	Net Benefits	$0.35	$0.60	-$3.96	$76.87
Future Period Sensitivity 2 (MCT&D $46.50/kW-year)	Benefits	$80.84	$92.34	$88.13	$88.13
	Costs	$91.28	$91.28	$80.84	$0.00
	Net Benefits	-$10.44	$1.07	$7.29	$88.13
Future Period Sensitivity 3 (Peak Period MCE increase by 16%)	Benefits	$80.84	$92.48	$92.48	$92.48
	Costs	$91.28	$91.28	$80.84	$0.00
	Net Benefits	-$10.44	$1.20	$11.65	$92.48
Future Period Sensitivity 4 (Elasticities increase by 27%)	Benefits	$86.23	$92.12	$87.99	$87.99
	Costs	$91.19	$91.19	$86.23	$0.00
	Net Benefits	-$4.96	$0.93	$1.76	$87.99
Future Period Sensitivity 5 (Program Costs $1.00/cust./mo. & Peak Period MCE increase by 10%)	Benefits	$80.84	$88.21	$88.21	$88.21
	Costs	$87.13	$87.13	$80.84	$0.00
	Net Benefits	-$6.29	$1.08	$7.37	$88.21
Future Period Sensitivity 6 (Program Costs $1.00/cust./mo. & MCT&D $42.50/kW-year)	Benefits	$80.84	$88.32	$84.10	$84.10
	Costs	$87.13	$87.13	$80.84	$0.00
	Net Benefits	-$6.29	$1.19	$3.27	$84.10
Future Period Sensitivity 7 (Program Costs $0.925/cust./mo. paid by Utility)	Benefits	$80.84	$81.09	$76.87	$76.87
	Costs	$4.11	$80.90	$157.63	$76.79
	Net Benefits	$76.73	$0.19	-$80.76	$0.08

JB/jb