CHAPTER VI. DEMAND RESPONSE

A. Introduction

This chapter describes the results of PSE's initial evaluation of a specific form of customer demand response in terms of its potential to help meet part of PSE's need for new electric capacity resources. The chapter begins by reviewing the analysis of capacity resource adequacy levels and generation-based sources of peaking capacity that were considered in the April 30 Least Cost Plan. The April 30 Least Cost Plan also noted that winter peak-oriented demand response may be a cost-effective non-generation form of capacity resource. Section C of this chapter describes the analytical approach used in this Least Cost Plan Update to evaluate demand response as a potential source of winter-peaking capacity. The final section summarizes the conclusions reached in this preliminary analysis.

B. Issue Definition

For the April 2003 Least Cost Plan, PSE examined different levels of resource adequacy, including amounts of firm capacity resources to meet winter peak loads on days that the minimum hour temperature at Sea-Tac Airport falls to the following levels:

- 23 degrees Fahrenheit
- 19 degrees Fahrenheit
- 16 degrees Fahrenheit
- 13 degrees Fahrenheit

The load-resource portfolio analysis of these capacity-planning levels included two primary forms of electric peaking supply resources: single-cycle gas-fired combustion turbines (SCGTs), and the addition of duct firing to increase the peak generating capacity of combined-cycle gas-fired combustion turbines (CCGTs). These two forms of peaking generation were assumed to be the marginal resource technologies available to meet winter peak loads on PSE's electric system.

Based on the assumptions used for the April 2003 Least Cost Plan, PSE's load-resource portfolio analysis indicated that expected costs tend to rise at higher levels of capacity resource adequacy (i.e., at lower temperatures). However, PSE also recognized that it has obligations to plan and acquire sufficient resources to meet the winter peak loads that are reasonably likely to occur for its retail electric customers. . Further, it was also apparent that SCGTs and duct firing for CCGTs may not necessarily be the most cost-effective form of capacity resource to meet all peaking needs. This is particularly evident when moving to progressively higher levels of capacity resource adequacy, which require the addition of more fixed capacity costs to prepare for cold weather events that become progressively less likely to occur at lower and lower temperature levels.

For example, PSE's forecasted winter peak-hour electric load on a 16-degree day is expected to be about 200 MW higher than the peak-hour electric load on a 23-degree day. However, while there is roughly a 50 percent chance that a 23-degree day will occur during a winter season, the chance of a 16-degree day occurring is much lower. So the fixed costs to acquire and hold 200 MW of additional SCGT capacity to cover the added capacity needs for a 16-degree day appear quite high, especially since there is less than a 50 percent likelihood during a winter season of a colder than 23-degree day occurring. (Note that it might be possible to recoup a portion of the fixed costs for SCGTs by operating them and selling surplus power during periods when the SCGTs are not needed to serve PSE's retail loads and wholesale power prices are higher than variable costs. However, PSE's integrated load-resource portfolio analysis has confirmed that significant risks can be created by depending on net revenues from market sales of surplus power from generating resources that are surplus to retail customer needs.)

In the April 2003 Least Cost Plan, PSE also acknowledged that other forms of winter capacity resources may be available and may be more cost-effective than relying exclusively on SCGTs and duct firing for CCGTs. This, combined with other considerations, including recognition of PSE's responsibility to meet its customers' peaking needs, resulted in selection of a planning standard at the 16-degree level. Further, the April 30 Least Cost Plan identified demand response as a potential source of winter peaking capacity, and included an Action Plan item to investigate whether peak-oriented demand response programs could be a more cost-effective alternative than SCGTs.

C. Overview of Approach for this Least Cost Plan Update

There are many possible forms of demand response programs that could be developed and implemented to serve a variety of purposes. For the August 2003 Least Cost Plan Update, PSE has conducted a preliminary analysis of one specific form of demand response, where the primary emphasis for this analysis is from the long-term resource planning perspective. As described above, PSE has identified that SCGTs may not represent the most cost-effective form of electric capacity resource, especially to meet winter peak loads at progressively lower temperatures that have a diminishing likelihood of occurring. Therefore, PSE has evaluated demand response as a potential source of winter peaking capacity that could help to meet retail peak-hour loads on cold winter days.

The analysis of demand response for the August 2003 Least Cost Plan Update includes the following steps:

1. Investigate whether there is sufficient demand response potential among PSE's retail electric loads to reduce total peak-hour loads (on a 16-degree day) by the expected difference in peak-hour loads on a 16-degree day versus a 23-degree day. In other words, identify whether there may be enough demand response potential to achieve a peak-hour load reduction of 200 MW or more.
2. Develop estimates of costs to implement several forms of demand response programs that could be used to reduce peak-hour loads on cold winter days.
3. If the results from steps 1 and 2 appear promising, use PSE's portfolio screening model to evaluate costs for two electric resource portfolios that include sufficient capacity to meet the following levels of peak-hour loads:
   (a) resource portfolio with sufficient capacity resources (excluding demand response) to meet peak-hour loads on a 16-degree day.
   (b) resource portfolio with sufficient capacity resources (excluding demand response) to meet peak-hour loads on a 23-degree day.
4. Subtract the power costs developed in step 3 for the 23-degree portfolio from the power costs for the 16-degree portfolio. This difference represents the costs that could be avoided by using demand response rather than SCGTs to meet the increase in peak-hour loads that is expected to occur on a 16-degree day relative to a 23-degree day.

D. Results of Preliminary Analysis

For the August 2003 Least Cost Plan Update, the results of the first two steps described above are presented in a memorandum and tables prepared by Charles River Associates. These results are provided in the attachment that follows the body of this chapter. The results indicate that more than 200 MW of demand response may be available to help meet peak-hour loads on cold winter days, and that the costs for this type of demand response program appear attractive relative to SCGTs. However, this comparison does not yet reflect the net impacts on PSE's overall electric resource portfolio.

Accordingly, PSE has used the portfolio screening model as described in steps 3 and 4 above to evaluate the potential value of demand response. This analysis is described in Chapter VII. Results of the portfolio analysis indicate that reducing the reliance on SCGTs to meet peak-hour electric loads on cold winter days could save between $7 million and $9 million per year. These results indicate that if a demand response program could be developed and implemented to reduce peak-hour loads on cold winter days by about 200 MW at a cost of less than $7 million to $9 million per year, such an approach would be more cost-effective than a resource strategy that relies on SCGTs to meet that amount of winter peak load.

MEMORANDUM

To: Charlie Black, Puget Sound Energy **CRA No.** D0-3471-00

From: Ahmad Faruqui

Date: July 9, 2003

cc: Joanna Burleson, Eric Englert (PSE), Steve George, Bill Hopkins (PSE)

Subject: **WINTER PEAK CLIPPING PROGRAMS**

CRA has performed a review of winter peak clipping programs, in support of PSE's August 31, 2003 update of the Least-Cost Plan that was filed on April 30, 2003. Unlike summer peak clipping programs, which are widespread in North America, there are comparatively few winter peak-clipping programs in operation. Several of these programs have not been evaluated rigorously, and they have yielded no data on kW impacts per customer. Cost data are even harder to come by.

Nevertheless, by contacting several utilities through the phone and e-mail, and by reviewing the information in CRA's archives, we have identified several programs on which data is available and which are likely to be of interest to PSE.

These programs fall into the following four categories:

- Traditional direct load control programs involving residential end uses such as water heating and space heating. These programs have been the mainstay of utility peak clipping efforts for the past half-century. They involve the payment of a fixed incentive per month or season to customers, in return for their letting the utility cycle their appliances for a certain number of times during the peak season. A communication network has to be set up for sending the signals to customer appliances, and receiver switches need to be installed on customer appliances.

- Traditional curtailable and interruptible rate programs directed at commercial and industrial (C&I) customers. These programs have also been the mainstay of utility peak clipping programs, perhaps for the past quarter-century. In return for getting a lower rate year-round, the customer agrees to curtail service for several hours during the year when poor reliability conditions are encountered.

- Incentive-based load curtailment programs. These programs were created in the aftermath of the power crisis in the Western states, when utilities discovered they had used up the number of times they could interrupt or curtail customers. Customers are paid $X per MWh curtailed during emergency conditions that may be triggered by a price spike or reliability conditions. Sometimes, the programs also make a monthly reservation payment to customers and impose a penalty on those customers who do not comply with the agreed on curtailment amounts. A pre-requisite for these programs is an agreed on methodology for measuring customer base load (CBL), against which the curtailed amounts can be measured.[1] The programs are often run by Independent System Operators, but can be offered by utilities as well. In a variant of the program design, customers may bid “negawatts” of load reductions at pre-specified prices. These bidding programs have not proven very popular with customers, and we have not included them in our survey. Hourly load meters are required for these programs.

- Dynamic pricing programs. These include critical peak pricing and extreme day pricing programs, in addition to real-time pricing. Interval metering capability is required for these programs. No cash incentives are paid to customers, and in most cases there is no reason to estimate customer base loads (CBL).[2]

For each program, we sought to identify several features including (a) the nature of the program, its target market and duration, (b) the number of customers on the program and their applicable base load, (c) the load savings from the program in aggregate MWs as well as percent of base load, and (d) program costs, including the fixed cost and recurring one-time (e.g., those associated with the installation of meters on large customers) variable costs.

We then applied the information from this survey of other utility experiences to PSE’s load forecasts for January 2004. Our analysis was performed by customer class. We grouped customers into three classes, comprised of residential, commercial and industrial (exclusive of the very largest customers who procure their own power).

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[1] E.g., in the state of New York, the CBL for a given hour is the average use during that hour on the five highest of the ten most recent like days.

[2] The exception is two-part real-time pricing, where the first part of the bill is based on the customer’s baseline load.

Since any application of data from other utilities to PSE's service area is fraught with uncertainty, we categorized two types of uncertainty with an eye toward assessing their impact: (a) uncertainty in unit program impacts (i.e., savings per customer) and (b) uncertainty in the number of customer who are likely to be on the program. We picked low and high values for percent unit impacts to account for the first source of uncertainty. To capture the second source of uncertainty, we created three scenarios of program deployment: (a) universal deployment with a 90% opt-out rate, (b) universal deployment with a 50% opt-out rate and (c) a voluntary deployment with a 10% opt-in rate. We captured the impact of the uncertainties through Monte Carlo simulation with the Crystal Ball software, and used 10,000 iterations to measure the shape of the probability distribution.

We estimated the cost of saved peak-demand by performing a life-cycle analysis of program impacts and costs. By dividing the life-cycle costs by life-cycle impacts, we obtained an estimate of the levelized costs expressed in $/kW-year. Crystal Ball was used for estimating the uncertainties in the cost estimates as well.

The detailed results of the analysis are contained in Tables 1, 2 and 3, which are included in a separate file that accompanies this memorandum. Table 1 contains the unit impacts and aggregate impacts of winter peak clipping programs, aggregated by sector. This table identifies the sources used to develop the estimates and predicts likely impacts for PSE under alternative scenarios of unit impacts and program deployment. Low, medium and high estimates are reported in this table, representing the 10th, 50th, and 90th percentiles of the simulated probability distributions. Table 2 contains estimates of program fixed and variable costs. Table 3 contains estimates of the cost of saved peak demand, expressed in $/kW/year.

In aggregate terms, the impacts range from a low value of 261 MW to a high value of 1,058 MW, with a mid-point of 572 MW. More than 75% of the impacts are concentrated in the residential sector and most of them can be obtained at costs that are under $16/kW/year.

Those who want to review programmatic details can consult Tables 1A, 2A and 3A, which show how the impacts were developed at the level of individual programs within the three sectors.

Table 1: MW Reductions by Customer Sector

	Class MW	Customer Count	kW per customer	Aggregate MW Reduction [Note 4]		
				Low	Mid	High
Residential [Note 1]	3,592	863,863	4.16	215	457	804
Commercial [Note 2]	1,053	106,073	9.93	38	92	203
Industrial [Note 3]	175	3,855	45.35	8	22	51
System Total [Note 5]	4,819	973,791		261	572	1,058

Notes:

[1] Residential winter peak clipping options reviewed include critical peak pricing (CPP), extreme day pricing (EDP), direct load control (space heating), and direct load control (water heating).

[2] Commercial winter peak clipping options reviewed include CPP, EDP, interruptible and curtailment rates, incentive-based load curtailment, and standby generator control.

[3] Industrial winter peak clipping options reviewed include CPP, EDP, interruptible and curtailment rates, incentive-based load curtailment, and standby generator control.

[4] Aggregate MW reduction estimates are generated using Monte Carlo simulation. Low corresponds to the 10th percentile, mid to the 50th percentile, and high to the 90th percentile for the forecast. The following uncertainties are represented in the analysis: fixed and variable costs, customer participation rates, and unit impacts.

[5] System Total is a summation of the three sector impacts.

Sources:

[1] Comparatively few utilities are winter peaking and there are even fewer utilities with active winter peak clipping programs. The estimates in this table have been gathered through a literature search, supplemented with phone calls and e-mails with several utilities, commissions and other regulatory bodies. Hydro Quebec has a residential Dual-Energy rate option which uses a dual-energy heating system equipped with an automatic switch permitting the transfer from one source to the other when exterior temperature falls below a specific threshold.

[2] Unit impacts for the residential CPP option are based on Gulf Power's estimated reduction of 2.37 kW reduction per customer during the winter months. General Public Utilities (GPU) in Pennsylvania has reported an impact of 1.24 kW per customer during the summer, a 50% drop in base usage, achieved with enabling technology (smart thermostat).

[3] EDP impacts are calculated using the ratio of CPP impacts to EDP impacts from Xcel CEM analysis and applying this ratio to CPP impacts estimated for PSE. The ratios vary between Residential and C&I sectors.

[4] Unit impacts of 54% for direct load control (space heating) calculated from estimated reductions from PSE's Home Comfort Control Thermostat Study.

[5] Unit impacts of 14% for direct load control (water heating) from the Duke Power program, which indicated a drop of .5 kW on a base use of 3.57 kW. Impacts are based on Summer data.

[6] Unit Impacts for the commercial and industrial CPP options are from CRA's analysis of PSE data, based on a base price of 6.67 cents/kWh and CPP price of 13.91 cents/kWh (04/18/02), using price elasticities from the literature survey reported in Ahmad Faruqui and Stephen S. George, "The Value of Dynamic Pricing in Mass Markets," The Electricity Journal, July 2002.

[7] Interruptible and curtailment rate impacts from: Ahmad Faruqui et al., "Customer Responses to Rate Options." EPRI CU-7131, Barakat & Chamberlin. (January 1991).

[8] Low impact estimate for Incentive-based Load Curtailment option from B.C Hydro's Price Dispatched Curtailment Program.

Table 1: MW Reductions by Customer Sector

[9] High impact estimate for Incentive-Based Load Curtailment option from "How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance," Neenan Associates, Ernest Orlando Lawrence Berkeley National Laboratory, and Pacific Northwest National Laboratory, January 2003. The average implicit price elasticity was estimated by Bernie Neenan, Richard Boisvert and Peter Cappers in the April 2002 Electricity Journal to be -.09, which implies that program participants would reduce their usage during curtailment periods by about 38 percent, when they were given an incentive of $500/MWh to cut usage. The implicit price elasticities were found to vary by customer, and displayed an upper limit of -.47 for some customers.
[10] Saturation rates for electric water (61%) and space heating (13%) from Bill Hopkins at PSE.
[11] Standby generator control impacts are taken from high impacts from incentive-based curtailment programs.
[12] Class MW and customer counts are from the PSE Load Forecast for the month of January 2004.

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Table 2: Costs by Customer Sector

	Low	Mid	High
Residential [Note 1]	**$6,772,481**	**$11,013,494**	**$14,515,839**
Commercial [Note 2]	**$11,011,799**	**$12,707,077**	**$14,400,588**
Industrial [Note 3]	**$10,666,847**	**$12,360,208**	**$14,044,302**
System Total [Note 4]	**$28,451,127**	**$36,080,779**	**$42,960,729**

Notes:

[1] Residential winter peak clipping options reviewed include CPP, EDP, direct load control (space heating), and direct load control (water heating).

[2] Commercial winter peak clipping options reviewed include CPP, EDP, interruptible and curtailment rates, incentive-based load curtailment, and standby generator control.

[3] Industrial winter peak clipping options reviewed include CPP, EDP, interruptible and curtailment rates, incentive-based load curtailment, and standby generator control.

[4] System Total is a summation of the three sector impacts.

[5] Variation in the input assumptions is due to the uncertainty of fixed and variable costs, customer participation rates, and unit impacts.

[6] Industrial winter peak clipping options reviewed include CPP, EDP, interruptible and curtailment rates, incentive-based load curtailment, and standby generator control.

[7] Incentive payments for demand-response load curtailment programs can range from $250-500/MWH curtailed.

[8] Curtailment period for New York is 20 hours/year.

Sources:

[1] Total cost estimates are generated using Monte Carlo simulation. Low corresponds to the 10th percentile, mid to the 50th percentile, and high to the 90th percentile for the forecast.

[2] Variable and fixed costs for CPP, EDP, and incentive-based load curtailment rates are estimates from PSE.

[3] Direct load control water heating variable costs are from Duke Power's Residential Water Heater Load Control program. Fixed costs are from CRA estimates of Xcel Energy's Saver Switch Program.

[4] Incentive-based load curtailment variable costs/customer/year estimate are from PSE. Incentive payments estimates from "How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance," Neenan Associates, Ernest Orlando Lawrence Berkeley National Laboratory, and Pacific Northwest National Laboratory, January 2003.

[5] Standby generator control costs are based on high scenario costs for Incentive-Based Load Curtailment programs.

Table 3: Costs per kW Reduction

	First Year Costs ($/kW/Year)			Levelized Costs ($/kW/Year)		
	Low	**Mid**	**High**	**Low**	**Mid**	**High**
Residential	**$13**	**$23**	**$48**	**$5**	**$9**	**$16**
Commercial	**$62**	**$138**	**$337**	**$8**	**$17**	**$41**
Industrial	**$239**	**$553**	**$1,505**	**$25**	**$57**	**$155**

Notes:

[1] Levelized costs are calculated as total discounted costs for the term of the program divided by total discounted load impacts of the program, as defined by the California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects (October 2001).
[2] Term of all programs is set to 10 years.
[3] Discount rates are set to 0.
[4] Programs identified by the above ranges are not necessarily the same programs identified as low, mid, and high for unit impacts in Table 1 or low, mid, and high for total costs in Table 2.

Sources:

[1] Total costs/kW reduction estimates are generated using Monte Carlo simulation. Low corresponds to the 10th percentile, mid to the 50th percentile, and high to the 90th percentile for the forecast.

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Table 1A: kW Reduction by Customer Class

	Class MW	Existing kW per customer	Post-Curtailment kW per customer	Unit Impacts: Delta kW per customer	Unit Impacts: % Impacts	Customer Count	Aggregate MW Reduction: Universal Deployment (10% Opt Out)	Aggregate MW Reduction: 50% Opt-Out	Aggregate MW Reduction: 10% Opt-In
Residential									
Critical Peak Pricing (low impacts) [1]	3,592	4.16	3.12	1.04	-25%	863,863	808.1	449.0	89.8
Critical Peak Pricing (high impacts) [1]	3,592	4.16	2.08	2.08	-50%	863,863	1,616.3	897.9	179.6
Extreme Day Pricing [2]	3,592	4.16	2.85	1.31	-31%	863,863	1,014.9	563.8	112.8
Direct Load Control-Space Heating [3] [9]	467	4.16	1.91	2.25	-54%	112,302	226.9	126.1	25.2
Direct Load Control-Water Heating [4] [9]	2,191	4.16	3.57	0.58	-14%	526,956	276.8	153.8	30.8
Commercial									
Critical Peak Pricing [5]	1,053	9.93	9.23	0.69	-7%	106,073	66.3	36.8	7.4
Extreme Day Pricing [2]	1,053	9.93	9.44	0.48	-5%	106,073	45.9	25.5	5.1
Interruptible and Curtailment Rates (low impacts) [6]	1,053	9.93	7.44	2.48	-25%	106,073	236.9	131.6	26.3
Interruptible and Curtailment Rates (high impacts) [6]	1,053	9.93	4.96	4.96	-50%	106,073	473.8	263.2	52.6
Incentive-Based Load Curtailment (low impacts) [7]	1,053	9.93	9.43	0.50	-5%	106,073	47.4	26.3	5.3
Incentive-Based Load Curtailment (high impacts) [8]	1,053	9.93	8.04	1.89	-19%	106,073	180.0	100.0	20.0
Standby Generator Control [10]	105	9.93	8.04	1.89	-19%	10,607	18.0	10.0	2.0
Industrial									
Critical Peak Pricing [5]	175	45.35	42.18	3.17	-7%	3,855	11.0	6.1	1.2
Extreme Day Pricing [2]	175	45.35	43.16	2.20	-5%	3,855	7.6	4.2	0.8
Interruptible and Curtailment Rates (low impacts) [6]	175	45.35	22.68	22.68	-50%	3,855	78.7	43.7	8.7
Interruptible and Curtailment Rates (high impacts) [6]	175	45.35	11.34	34.01	-75%	3,855	118.0	65.6	13.1
Incentive-Based Load Curtailment (low impacts) [7]	175	45.35	40.82	4.54	-10%	3,855	15.7	8.7	1.7
Incentive-Based Load Curtailment (high impacts) [8]	175	45.35	28.12	17.23	-38%	3,855	59.8	33.2	6.6
Standby Generator Control [10]	44	45.35	28.12	17.23	-38%	964	14.9	8.3	1.7
System Load	4,819								

Sources:

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[1] Unit impacts for the CPP option are based on estimates from Gulf Power, resulting from a magnitude reduction of 2.37 kW reduction per customer during the winter months. General Public Utilities (GPU) in Pennsylvania has reported an impact of 1.24 kW per customer during the summer, a 50% drop in base usage. 50% impacts achieved with enabling technology (smart thermostat). 25% Impacts represent a case without enabling technology.

Residential and C&I sectors.

[3] Unit impacts of 54% calculated from estimated reductions from PSE's Home Comfort Control Thermostat Study.

[4] Unit impacts of 14% from the Duke Power program, which indicated a drop of .5 kW on a base use of 3.57 kW. Impacts are based on Summer data.

[5] Unit Impacts for the CPP option are from CRA's analysis of PSE data, based on a base price of 6.67 cents/kWh and CPP price of 13.91 cents/kWh (04/18/02), using price elasticities from the literature survey reported in Ahmad Faruqui and Stephen S. George, "The Value of Dynamic Pricing in Mass Markets," The Electricity Journal, July 2002.

[6] Ahmad Faruqui et al., "Customer Responses to Rate Options." EPRI CU-7131, Barakat & Chamberlin. (January 1991).

[7] Low impact estimate for Incentive-based Load Curtailment option from B.C Hydro's Price Dispatched Curtailment Program.

Program Performance," Neenan Associates, Ernest Orlando Lawrence Berkeley National Laboratory, and Pacific Northwest National Laboratory, January 2003. The average implicit price elasticity was estimated by Bernie Neenan, Richard Boisvert and Peter Cappers in the April 2002 Electricity Journal to be -.09, which implies that program participants would reduce their usage during curtailment periods by about 38 percent, when they were given an incentive of $500/MWh to cut usage. The implicit price elasticities were found to vary by customer, and displayed an upper limit of -.47 for some customers.

[9] Saturation rates for electric water (61%) and space heating (13%) from Bill Hopkins at PSE.

[10] Impacts are taken from high impacts from incentive based curtailment programs.

Notes:

[1] Comparatively few utilities are winter peaking and there are even fewer utilities with active winter peak clipping programs. The estimates in this table have been gathered through a literature search, supplemented with phone calls and e-mails with several utilities, commissions and other regulatory bodies.

[2] Hydro Quebec has a residential Dual-Energy rate option which uses a dual-energy heating system equipped with an automatic switch permitting the transfer from one source to the other when

Table 2A: Costs by Demand-Response Option

	Variable Cost per Customer/Year	Customer Count	Variable Cost per MWH Reduced/Year			Total Variable Cost (per year)			Other Variable Costs (one time)	Program Fixed Cost	Total Cost		
			Universal Deployment	50% Opt-Out	10% Opt-In	Universal Deployment	50% Opt-Out	10% Opt-In			Universal Deployment	50% Opt-Out	10% Opt-In
Residential													
Critical Peak Pricing [1]	$12.00	863,863	$0	$0	$0	$9,329,717	$5,183,176	$1,036,635	$0	$12,350,000	$21,679,717	$17,533,176	$13,386,635
Extreme Day Pricing [1]	$12.00	863,863	$0	$0	$0	$9,329,717	$5,183,176	$1,036,635	$0	$12,350,000	$21,679,717	$17,533,176	$13,386,635
Direct Load Control-Space Heating	N/A	112,302	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Direct Load Control-Water Heating [2]	$24.00	526,956	$0	$0	$0	$11,382,255	$6,323,475	$1,264,695	$0	$450,000	$11,832,255	$6,773,475	$1,714,695
Commercial													
Critical Peak Pricing [1]	$12.00	106,073	$0	$0	$0	$1,145,592	$636,440	$127,288	$0	$12,350,000	$13,495,592	$12,986,440	$12,477,288
Extreme Day Pricing [1]	$12.00	106,073	$0	$0	$0	$1,145,592	$636,440	$127,288	$0	$12,350,000	$13,495,592	$12,986,440	$12,477,288
Interruptible and Curtailment Rates	N/A	106,073	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Incentive-Based Load Curtailment (low variable cost) [3]	$12.00	106,073	$57,417	$31,899	$6,380	$1,203,009	$668,339	$133,668	$0	$12,350,000	$13,553,009	$13,018,339	$12,483,668
Incentive-Based Load Curtailment (high variable cost) [3]	$12.00	106,073	$436,373	$242,429	$48,486	$1,581,965	$878,869	$175,774	$0	$12,350,000	$13,931,965	$13,228,869	$12,525,774
Standby Generator Control [4]	$12.00	10,607	$43,637	$24,243	$4,849	$158,196	$87,887	$17,577	$0	$12,350,000	$12,508,196	$12,437,887	$12,367,577
Industrial													
Critical Peak Pricing [1]	$12.00	3,855	$0	$0	$0	$41,632	$23,129	$4,626	$0	$12,350,000	$12,391,632	$12,373,129	$12,354,626
Extreme Day Pricing [1]	$12.00	3,855	$0	$0	$0	$41,632	$23,129	$4,626	$0	$12,350,000	$12,391,632	$12,373,129	$12,354,626
Interruptible and Curtailment Rates	N/A	3,855	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Incentive-Based Load Curtailment (low variable cost) [3]	$12.00	3,855	$20,741	$11,523	$2,305	$62,373	$34,652	$6,930	$0	$12,350,000	$12,412,373	$12,384,652	$12,356,930
Incentive-Based Load Curtailment (high variable cost) [3]	$12.00	3,855	$157,632	$87,573	$17,515	$199,264	$110,702	$22,140	$0	$12,350,000	$12,549,264	$12,460,702	$12,372,140
Standby Generator Control [4]	$12.00	964	$39,408	$21,893	$4,379	$49,816	$27,676	$5,535	$0	$12,350,000	$12,399,816	$12,377,676	$12,355,535

Sources:

[1] Variable and fixed costs for CPP and EDP rates are estimates from PSE

[2] Variable costs are from Duke Power's Residential Water Heater Load Control program. Fixed costs are from CRA estimates of Xcel Energy's Saver Switch Program.

[3] Variable costs/customer/year estimate are from PSE. Incentive payments estimates from "How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance," Neenan Associates, Ernest Orlando Lawrence Berkeley National Laboratory, and Pacific Northwest National Laboratory, January 2003.

[4] Standby Generator costs are based on high scenario costs for Incentive-Based Load Curtailment programs.

[5] Incentive based load curtailment programs have the same $12.35 million fixed cost as CPP and EDP.

Notes:

[1] Incentive payments for demand-response load curtailment programs can range from $250-500/MWH curtailed.

[2] Curtailment period for New York is 20 hours/year.

Puget Sound Energy
Winter Peak Clipping Options

Table 3A: Costs per kW Reduction

	First Year Costs ($/kW/Year)			Levelized Costs ($/kW/Year)		
	Universal Deployment	50% Opt-Out	10% Opt-In	Universal Deployment	50% Opt-Out	10% Opt-In
Residential						
Critical Peak Pricing (low impacts)	$26.83	$39.05	$149.08	$13.07	$14.30	$25.30
Critical Peak Pricing (high impacts)	$13.41	$19.53	$74.54	$6.54	$7.15	$12.65
Extreme Day Pricing	$21.36	$31.10	$118.71	$10.41	$11.38	$20.15
Direct Load Control-Space Heating	N/A	N/A	N/A	N/A	N/A	N/A
Direct Load Control-Water Heating	$42.75	$44.05	$55.76	$41.29	$41.42	$42.59
Commercial						
Critical Peak Pricing	$203.48	$352.44	$1,693.10	$35.89	$50.79	$184.86
Extreme Day Pricing	$294.26	$509.68	$2,448.49	$51.91	$73.45	$267.33
Interruptible and Curtailment Rates (low impacts)	N/A	N/A	N/A	N/A	N/A	N/A
Interruptible and Curtailment Rates (high impacts)	N/A	N/A	N/A	N/A	N/A	N/A
Incentive-Based Load Curtailment (low impacts and variable cost)	$286.08	$494.63	$2,371.56	$51.46	$72.32	$260.01
Incentive-Based Load Curtailment (high impacts and variable cost)	$77.39	$132.27	$626.20	$15.65	$21.14	$70.53
Standby Generator Control	$694.80	$1,243.61	$6,182.90	$77.39	$132.27	$626.20
Industrial						
Critical Peak Pricing	$1,125.11	$2,022.17	$10,095.73	$115.91	$205.62	$1,012.97
Extreme Day Pricing	$1,627.08	$2,924.37	$14,599.97	$167.63	$297.36	$1,464.92
Interruptible and Curtailment Rates (low impacts)	N/A	N/A	N/A	N/A	N/A	N/A
Interruptible and Curtailment Rates (high impacts)	N/A	N/A	N/A	N/A	N/A	N/A
Incentive-Based Load Curtailment (low impacts and variable cost)	$788.89	$1,416.84	$7,068.33	$82.46	$145.25	$710.40
Incentive-Based Load Curtailment (high impacts and variable cost)	$209.89	$375.14	$1,862.38	$23.99	$40.51	$189.24
Standby Generator Control	$829.57	$1,490.57	$7,439.50	$85.96	$152.06	$746.95