825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

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PAC-E-03-03

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November 28, 2003

Idaho Public Utilities Commission
472 West Washington
Boise, ID 83702-5983

Attention: Jean D. Jewell
Commission Secretary

Re: Idaho 2003 Irrigation Load Control Credit Rider Program Impact Evaluation Report

Pacificorp (d.b.a. Utah Power & Light Company) hereby submits an original and eight copies of the Idaho 2003 Irrigation Load Control Credit Rider Program Impact Evaluation Report.

The purpose of this filing is to comply with Commission Order No. 29209 where in the Company was directed to submit a report at the end of the 2003 irrigation season summarizing the results of Irrigation Load Control Credit Rider program (Program). The required Program evaluation is provided herein as Attachment A.

Also in compliance with Commission Order No. 29209 the Company recommends the following changes to improve the program. The intent of these recommendations is twofold: (1) streamline the enrollment process and (2) mitigate potential customer concerns that may have limited customer participation in the 2003 Program.
The Company proposes to:

1. Provide customers with a *Load Control Service Agreement* by January 15th of each year together with the *Load Control Service Credit* notification (the credit the customer would receive should they elect to participate). The Load Control Service Agreement will include the amount of credit the customer would receive during the upcoming irrigation season if participation is elected.
2. Require that customers sign and return the *Load Control Service Agreement* by February 15th of each year to indicate their intention to participate in the *Program*.
3. Notify participating customers of the scheduled hours for load control during the irrigation season by March 15th of each calendar year.
4. Permit participating customers to notify the Company of their intent to opt out of the *Program* without penalty by April 15th. Under the Company proposal customers

notifying the Company of their intent to opt out of the *Program* after April 15th shall be subject to the terms of Special Condition No. 7, Early Termination (Schedule No. 72).

5. Not enforce the ineligibility for the 2004 irrigation season for customers who submitted an *Intent to Participate Notification* in the in 2003 *Program*, but subsequently failed to execute a *Load Control Service Agreement*. This proposal is based on the Company's recommendation to eliminate the *Intent to Participate Notification* as part of the 2004 Program.
6. To limit the potential cost for participating customers under terms of Special Condition No 8, Cost of Load Control Devices, (Schedule No. 72) to such costs only to the extent that they exceed one thousand dollars.

The Company will separately file tariff changes reflecting these recommendations together with the Load Control Service Credit for the 2004 irrigation season.

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to :

By E-mail (preferred):	datarequest@pacificorp.com
By Fax:	(503) 813-6060
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah St., Suite 800 Portland, OR 97232

Informal questions should be directed to Bob Lively (801) 220-4052.

Sincerely,

Doug Larson / AN2

Doug Larson
Vice President, Regulation

Enclosures

ATTACHMENT A

IDAHO 2003 IRRIGATION LOAD CONTROL CREDIT RIDER PROGRAM IMPACT EVALUATION REPORT

NOVEMBER 2003

Final Report

Idaho 2003 Irrigation Load Control Credit Rider Program Impact Evaluation

Submitted to:
PacifiCorp

Prepared by:
Allen Lee, Ph.D.
Brian Hedman
Collin Elliot
Quantec, LLC

November 2003

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I. Introduction

Background

Pursuant to the Company's commitment and Commission Order No. 29034, PacifiCorp agreed to work with irrigators to develop an optional load control program beginning with the 2003-irrigation season. In December 2002 and January 2003 the Company met with representatives of the *Idaho Irrigation Pumpers Association* and the irrigation customer class to explain the Company's proposed program and to solicit comments and suggestions from the impacted customers. Based on feedback from customers, PacifiCorp filed its proposed *Irrigation Load Control Credit Rider Program* (Program) on January 31, 2003. On March 17, 2003, the Idaho Commission approved the PacifiCorp Program for implementation beginning with the 2003 irrigation season.

Response to the Idaho Public Utilities Commission Staff Recommendations

In March 2003 the Idaho Public Utilities Commission issued Order No. 29209. The order included IPUC Staff recommendations for PacifiCorp to prepare a report as follows:

> *...prepare a detailed report on the program and file it with the Commission. The filing should be made no later than December 1, 2003 and should contain the number of irrigation customers who 1) were eligible to participate in the program, 2) filed a letter of intent to participate, 3) entered into a load control service agreement, 4) participated in the program for the full three and one-half months and 5) those not eligible to participate next year. The report should also include the total dollar amount of credits provided under the program identified by month. The filing should further include any proposed changes or recommendations to improve the program. (Order No. 29209, page 3)*

Commission Findings in Order No. 29209 directed the Company to:

> *...submit a report at the end of the irrigation season summarizing its results. The report once filed will be noticed for comment and we anticipate that recommendations for program changes will result in an improved program for the 2004 irrigation season. (Order No. 29209, page 5)*

The following information responds to the aforementioned IPUC Staff recommendations. Table I.2 provides the data requested regarding customer participation.

Table I.2: Number of Irrigation Customers by Category

Customer Category	Number
Were eligible to participate in the program	2,015 accounts / 4,466 individually metered sites
Filed a letter of intent to participate	915
Entered into a load control service agreement	207 different customers / 403 individually metered sites
Participated in the program for the full three and one-half months	207 customers / 402 sites
Were not eligible to participate next year	708

The total dollar amount of credits provided under the program, identified by month, are summarized in Table I.3. Additionally, Table I.4 shows the actual avoided demand by month and control period.

Table I.3: 2003 Avoided Demand and Participation Credit (LCSC)

Month	End-Use Customer Participation Credit
June	$60,971.03
July	$93,539.55
August	$97,749.45
September	$25,323.69
Total participation credit	$277,583.72

Note: Avoided demand (kW) shown should be divided by two to derive the effective average control-day avoided demand. This is because each irrigator was controlled only two of the four possible control days. Actual avoided demand by control day is presented in Table I.4

II. Data and Assumptions

Energy Data and Benefits Valuation

PacifiCorp provided the data used in this evaluation. For this Program, Quantec saw no need to collect energy impact data independently for the following reasons:

- The design of the Program was straightforward–participating pumps were required to be off for the full period during control days
- PacifiCorp had good documentation on which pumps were participating and their power rating
- PacifiCorp did measure loads on specific circuits and substations and the results clearly demonstrated dramatic power drops during the control periods
- Random inspections conducted at about 8% of the participating sites found that the equipment was performing flawlessly and that only 3% (1 of 32) of the participants had done anything to override the control system.[1]

Figure II.1 demonstrates the impact of the Program on the irrigation daily load shape. These SCADA data are from the /IDAHO/BGRASY transmission substation (CB #67) and show measured loads recorded during selected days. This substation was selected because it had a substantial number of Program participants (participants represented 29% of this circuit's load). The graph shows the loads averaged for the control days Monday/Wednesday and Tuesday/Thursday and for Friday, a non-control day. Although the load shape and magnitudes vary by day, the impact of the Program is clearly shown as a significant and sharp load drop during the control hours.[2] This figure, although not conclusive, is consistent with the expected impact of the Program on demand during the control period.

1 The participant had not intentionally tried to violate the system control but had damaged it during an emergency situation.

2 The actual levels of demand displayed for the different days should be considered only illustrative since the data represent only five days out of the entire irrigation season. The levels are likely to be influenced by exogenous and short-term variables such as weather, non-irrigation loads, and agricultural practices. A more accurate display of relative usage magnitudes would require longer-term measurements.

Table I.4: 2003 Actual Avoided Demand Realized by Control Period

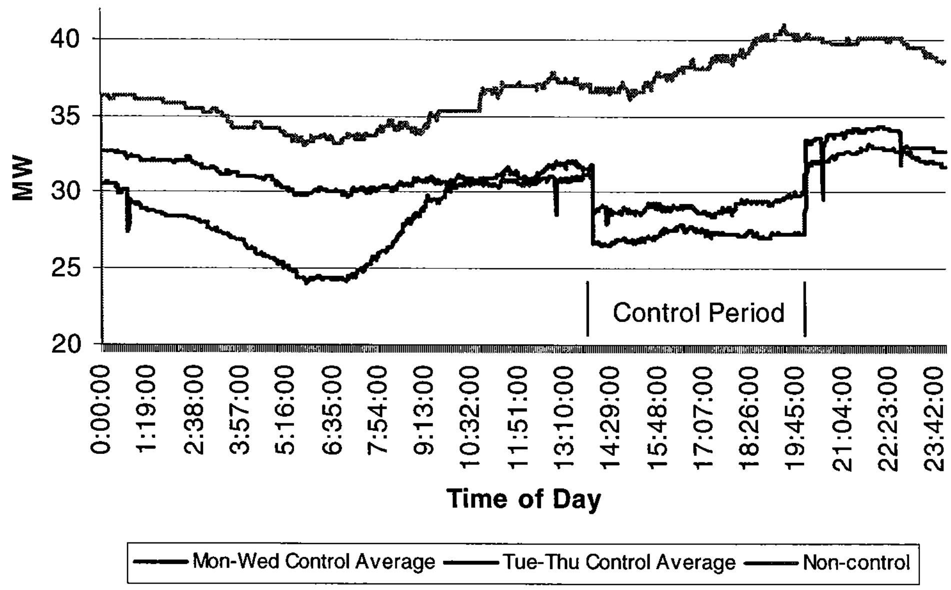
Control Period	June Avoided kW	July Avoided kW	August Avoided kW	September Avoided kW
Monday / Wednesday	20,533.67	23,782.00	22,861.67	20,976.00
Tuesday / Thursday	19,012.00	21,881.00	20,643.67	18,297.00
Mean Avoided kW	19,772.84	22,831.50	21,752.67	19,636.50
Total Avoided kW	*39,545.67*	*45,663.00*	*43,505.34*	*39,273.00*

Overview of Evaluation Approach

Quantec's impact evaluation estimated the benefits and costs of this Program and used them as inputs to the cost-effectiveness analysis. Cost effectiveness was assessed based on the benefit/cost ratio calculated from alternative perspectives.

PacifiCorp provided measured and calculated energy impact data for the analysis. It also provided detailed Program cost data. Quantec used its Demand Impact Cost Effectiveness (DICE) model to calculate the stream of Program benefits and costs during the expected life of the Program and calculated present discounted values. These values were then used to derive the benefit/cost ratios. Quantec has used this model and approach to evaluate numerous utility programs in the past.

Figure II.1: Load Shapes for Control and Non-control Days



To assess the costs and benefits associated with the clear demand response of participating customers, it is necessary to understand how the Program influenced participants' overall irrigation behavior. To provide this information, PacifiCorp's irrigation expert obtained feedback from participating customers. PacifiCorp found that, in addition to reducing demand during the control periods, Program participants were not making up for the foregone irrigation by increasing irrigation in non-control periods. The behaviors of irrigators that allowed them to reduce total irrigation on participating fields included the following:

- Irrigators were able to enroll locations that they believed could tolerate the measurable amount of water that will be avoided as a function of the imposed control schedule. This decision is a function of the soil type, the system used to deliver the water (e.g., circle irrigation, line irrigation etc.), the growing season, and forecasted climatic conditions (rainfall, temperature, Cooling Degree Days, relative humidity, etc.).
- Irrigators have the option to manipulate the crop rotation pattern such that drought resistant crops can be synched to pumps and irrigation systems nominated for participation in the Program. Crops such as hay, grain, peas, and corn would typically be good candidates for Program inclusion.

- Irrigators were able to make a business decision taking into account their risk preferences, given their anticipated "strike price" for a particular commodity. Irrigators were able to choose whether to participate given the certainty of the Program curtailment credit and their perception of market conditions and their risk assessment.

This finding had a direct implication on the impact analysis. Although the Program was implemented primarily as a way to reduce demand during peak periods, it also resulted in energy savings. Because the aggregate demand reduction (on the order of 20 MW per control day) was relatively small compared to total system demand and incremental additions of this magnitude to a utility's generation resource mix are unlikely, it was impractical to estimate its benefits in terms of avoided demand alone. Instead, PacifiCorp calculated the value of *energy savings* using the Integrated Resource Planning (IRP) Decrement approach for valuing Demand Side Management (DSM) programs. Fundamentally, the IRP Model calculates revenue requirements based on a given set of assumptions, including an hourly load forecast. Decrements (subtractions) to the load forecast are made based on the hourly shape of the DSM program modeled. Values are calculated with and without the Program. The difference, or decrement value, represents the most PacifiCorp would pay to avoid the load being modeled. The resulting values for avoided energy ($/MWh) based on the anticipated load shape of this Program are presented in Table II.1.

Table II.1: Estimated Value of Energy Savings

Year	Value of Energy Saved ($/MWh)
2003	$57.09
2004	$57.75
2005	$59.19
2006	$60.67
2007	$62.19

To estimate the energy and demand savings, PacifiCorp used the characteristics of the participating customers' loads. In 2003, there were 207 participants with a total of 403 independent participating sites. From its participant contracts and three-year average historical data, PacifiCorp knew the average historical demand of each site during each month. The total demand reduction for each control period (Mon/Wed and Tue/Thu) was estimated by customer and aggregated to calculate the total load reduction induced by the Program. Table II.2 presents the calculated demand reductions by period.

Table II.2: Avoided 2003 Aggregate Demand by Control Period

Control Period	Avoided kW			
	June	July*	August	September
Monday/Wednesday	20,534	23,782	22,862	20,976
Tuesday/Thursday	19,012	21,881	20,644	18,297

Note: In 2004 and subsequent Program years, the July estimated avoided demand for the Mon/Wed period is 24,489 kW and for the Tue/Thu period it is 21,960 kW. In 2003, the values are slightly lower because several participants did not participate for the full month.

The avoided energy economic benefits of the 2003 Program were calculated on a monthly basis using the following formula:

Energy Economic Benefits =
*[No. of Mon/Wed Control Days * Mon/Wed Control Days Avoided Demand*
*+ No. of Tue/Thu Control Days * Tue/Thu Control Days Avoided Demand]*
** Value of Energy Savings*

The values of energy savings are shown in Table II.1 for each year. For future years, these benefits are calculated using the same formula, but with the value of energy savings for the appropriate year.

For purposes of estimating future benefits and costs, we used PacifiCorp's evaluation assumption that the Program will continue for the five-year period 2003-2007. This assumption is used for evaluation purposes only. It is expected that the Program will continue indefinitely. PacifiCorp assumed that the same number of customers and sites would participate each year. Although participation was assumed to be constant, PacifiCorp's planning assumptions included the likelihood that some customers would drop out each year, but that others would be recruited to take their place. Given the strong response to the Program this year, Quantec believes that it is very reasonable to assume that participants who drop out can be replaced easily in future years. Future recruitment costs are discussed in the following section.

The economic benefits to Program participants include reduced utility bills and the PacifiCorp participation credit. Given that the participants respond to the Program by reducing their total energy consumption, Quantec calculated the utility bill savings by multiplying the marginal electricity rate for the average irrigator times the total energy savings for all participants. The average irrigator consumes 43,000 kWh/month, and the applicable rate for this level of consumption is $0.048/kWh.[3]

The participation credit benefit to participants is discussed in the next section as it is treated as a Program cost from the utility's perspective.

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3 Utah Power estimated this consumption level based on an assumption of a 100 hp pump motor, with a 75% load factor, operating 18 hours per day for a 30-day month.

Since the Program does not affect customers' peak demand on non-control days, we have assumed the Program does not reduce the participants' monthly peak demand. Consequently, no participant economic benefits were attributed to reductions in charges (power rate) based on maximum demand.

Costs

PacifiCorp provided a breakdown of 2003 Program year costs and forecasts of future-year costs. We used both the 2003 cost data and projections for future years in our analysis.

Table II.3 summarizes the costs provided by PacifiCorp. The values for 2003 are actual costs. All values are reported in current dollars and all costs except field expenses and interruption credits are assumed to escalate at a rate of 3% per year.

Table II. 3: Program Costs

	2003	2004	2005	2006	2007
Administrative support	$9,613	$9,902	$10,199	$10,505	$10,820
Evaluation	$2,135	$2,199	$2,265	$2,333	$2,403
Filed Expenses	$250,223	$85,000	$90,000	$95,000	$100,000
Participation credits	$277,584	$277,584	$277,584	$277,584	$277,584
Program management	$10,993	$11,323	$11,662	$12,012	$12,373
Reporting	$352	$362	$373	$384	$396
Total Program costs	*$550,900*	*$386,370*	*$392,084*	*$397,819*	*$403,576*

Field expenses reflect potential costs for maintaining field equipment and recruiting new participants to replace any who drop out. Given the experience during the first Program year, Quantum believes that the estimates are conservative and that the actual field expense costs are likely to be less than those assumed by PacifiCorp.

The participation credit costs are constant for each year since the number of participants is assumed to be unchanged and, and the level of future credits is unknown. These credits are treated as a cost from the utility perspective. From the perspective of the participants, however, they are benefits.

The customers were not charged for costs of participating in this Program. Consequently, all Program costs are associated with expenditures by PacifiCorp.

III. Cost-Effectiveness Analysis

Cost-Effectiveness Analysis

Cost effectiveness was calculated using Quantec's DICE model. Procedurally, the model takes the first year kWh savings and allocates them over all the 8,760 hours in a year based on load shapes appropriate for each of end use being analyzed. The achieved hourly kWh savings are then multiplied by the appropriate avoided cost based on the time of day and season during which they occur (summer peak, summer off-peak, winter peak, etc.). The value of the savings is calculated for each year of the measure life and then discounted back to the present.

As part of this evaluation, Quantec conducted an analysis of the Program costs and benefits from the following perspectives:

1. ***Program Participants***: For participants, Program benefits include bill reductions and the participation credit payments participants received for demand reduction.
2. ***PacifiCorp***: From PacifiCorp's perspective, the benefits are in the form of reduced generation or power purchase costs. The costs include marketing and administration associated with funding the Program, as well as the equipment and installation expenses and participant credits.
3. ***Ratepayers***: All ratepayers (participants and non-participants) may experience an increase in rates to recover lost revenue, if any. This test (referred to as the Ratepayer Impact Measure Test, or RIM) includes all PacifiCorp Program costs plus lost revenues. On the benefits side, this test includes all reduced generation or power purchase costs.
4. ***Total Resource Cost Test (TRC)***: This test examines the Program benefits and costs from the perspective of the utility and its customers combined. On the benefit side, it includes reduced generation or power purchase costs. On the cost side, it includes costs incurred by both the utility and by the participants, but participant credits are excluded because they are transfer payments among customers.

Table III.1 summarizes the various components of the four tests.

Table III.1
Benefits and Costs of Various Tests for This Program

Test	Benefits	Costs
Participant	Value of bill savings from reduced consumption and participants' credit payments for demand reduction	None to participants
PacifiCorp	Value of avoided energy costs as calculated by PacifiCorp's IRP model	Program administrative, marketing, and equipment costs, and participant credits
RIM	Value of avoided energy costs as calculated by PacifiCorp's IRP model	Program administrative, marketing, and equipment costs; participant credits; lost revenues
TRC	Value of avoided energy costs as calculated by PacifiCorp's IRP model	Program administrative, marketing, and equipment costs

Inputs

As noted earlier, PacifiCorp provided the inputs Quantec used in the cost-effectiveness analysis. Quantec thoroughly reviewed these inputs and the assumptions behind them. All costs and benefits were provided in nominal terms (i.e., without eliminating the effect of inflation).

kWh Savings. Estimated energy savings in 2003 were 7,917,839 kWh annually. These savings were derived from the monthly demand reduction during each of the control periods (Mon/Wed and Tue/Thu), times the number of days in each control period each month, times six hours for each control period each day. In future years, the estimated annual energy savings are 7,964,999 kWh. This value is higher than the 2003 figure because, as noted before, several participants did not participate during the full month of July 2003. The monthly demand reductions in each control period were shown in Table II.2; the demand reduction summed over the Program months and control periods was 167,987 kW in 2003. In 2004 and subsequent years, this estimated value will be higher–168,773 kW–for the same reason that the energy savings will be higher, as discussed above.

Life. The Program impacts were calculated over the five-year evaluation term of the Program. In addition to an analysis over the Program evaluation term, we conducted an analysis for the first year only.

Participant Retail Electricity Rate. An energy rate of $0.048 per kWh was used, based on PacifiCorp's current tariff for irrigators and the average energy use of irrigation customers.

Program Costs. The costs to the utility included administrative support, evaluation, field expenses (equipment plus labor), participant interruption credits, Program management, and reporting.

Avoided Costs. Cost effectiveness was calculated based on PacifiCorp's estimate of the value of energy savings, as described in Chapter II. The effect of line losses is included in the avoided cost and in the calculation of benefits.

Discount Rates. To derive present discounted values, all future costs and benefits were discounted using nominal discount rates. The rate used in the TRC was 5.23% and the rate used in all other tests was 7.82%.

Results

Table III.2 summarizes the DICE model cost effectiveness outputs for the first year for the Program. The first-year numbers are based on actual Program data provided by PacifiCorp. The Program is cost effective in the first year (positive net present value and benefit/cost ratios exceeding 1.0) from the Total Resource Cost perspective. From PacifiCorp's perspective (UTC), the first year of the Program is not cost effective because this is when most costs are incurred. For participants (PART), the Program is cost effective in the first year, providing benefits of over $657,000 at no cost to the participants.

Table III.2:
Cost Effectiveness – First-Year Only

Perspective	Total Discounted Costs ($)	Total Discounted Benefits ($)	Net Present Value ($)	Benefit/Cost Ratio
TRC	273,317	452,029	178,712	1.65
UTC	550,900	452,029	(98,871)	0.82
RIM	931,146	452,029	(479,117)	0.49
PART	-	657,830	657,830	N/A
Detailed Results				
Benefits	TRC	UTC	RIM	PART
Avoided Costs	$ 452,029	$ 452,029	$ 452,029	
Bill Reduction				$ 380,246
Incentive Payments				$ 277,584
Total Benefits	$ 452,029	$ 452,029	$ 452,029	$ 657,830
Costs	TRC	UTC	RIM	PART
Program Administration	$ 23,094	$ 23,094	$ 23,094	
Participant Incentives	$ -	$ 277,584	$ 277,584	
Field Costs	$ 250,223	$ 250,223	$ 250,223	
Lost Revenues			$ 380,246	
Total Costs	$ 273,317	$ 550,900	$ 931,146	$ -

Table III.3 shows how energy and demand savings, costs, and benefits vary by year for the five-year evaluation term (2003 through 2007). For each year after the first, the results are based on an assumption that the number of participants is the same as in the first year.[4] Program costs vary by year, as shown previously in Table II.3. Table III.3 demonstrates that the Program becomes more cost effective over time. While the (undiscounted) benefits added each year remain constant, Program costs decline after the initial field expenses.[5]

Table III.3: Five-Year Cost-Effectiveness Summary

Perspective	Year	kWh Savings	kW Savings	Annual Benefits	Annual Costs	Cumulative Benefits	Cumulative Costs	Ratio (Based on Cumulative Values)
TRC	2003	7,917,839	167,987	$452,029	$273,316	$452,029	$273,316	1.65
	2004	7,964,999	168,773	$437,117	$103,380	$889,146	$376,696	2.36
	2005	7,964,999	168,773	$425,750	$103,402	$1,314,896	$480,098	2.74
	2006	7,964,999	168,773	$414,707	$103,184	$1,729,603	$583,282	2.97
	2007	7,964,999	168,773	$403,969	$102,751	$2,133,572	$686,032	3.11
UTC	2003	7,917,839	167,987	$452,029	$550,900	$452,029	$550,900	0.82
	2004	7,964,999	168,773	$426,617	$359,849	$878,646	$910,749	0.96
	2005	7,964,999	168,773	$405,542	$338,665	$1,284,188	$1,249,414	1.03
	2006	7,964,999	168,773	$385,533	$318,677	$1,669,721	$1,568,091	1.06
	2007	7,964,999	168,773	$366,530	$299,824	$2,036,251	$1,867,915	1.09
RIM	2003	7,917,839	167,987	$452,029	$931,147	$452,029	$931,147	0.49
	2004	7,964,999	168,773	$426,617	$714,617	$878,646	$1,645,764	0.53
	2005	7,964,999	168,773	$405,542	$667,702	$1,284,188	$2,313,466	0.56
	2006	7,964,999	168,773	$385,533	$623,850	$1,669,721	$2,937,316	0.57
	2007	7,964,999	168,773	$366,530	$582,864	$2,036,251	$3,520,180	0.58
PART	2003	7,917,839	167,987	$657,830	$-	$657,830	$-	N/A
	2004	7,964,999	168,773	$613,721	$-	$1,271,550	$-	N/A
	2005	7,964,999	168,773	$569,208	$-	$1,840,759	$-	N/A
	2006	7,964,999	168,773	$527,925	$-	$2,368,684	$-	N/A
	2007	7,964,999	168,773	$489,635	$-	$2,858,319	$-	N/A

For a five-year evaluation term, Table III.4 shows that the Program is cost-effective from both TRC and PacifiCorp's perspectives. To PacifiCorp, the net present value (NPV) of the Program is more than $168,000. From the participants' perspective, the NPV of the Program is more than $2.8 million. The RIM test is the only one under which the five-year Program is not cost

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4 The energy savings figures, however, were adjusted upward to account for full participation in July (as discussed earlier).

5 Note that while Table III.3 presents some of the same results as Table III.2, there are some small differences due to rounding.

effective. Energy-efficiency programs often do not pass this test because of the inclusion of lost revenues as a cost.

Table III.3:
Cost Effectiveness – Five-Year Offering

Perspective	Total Discounted Costs ($)	Total Discounted Benefits ($)	Net Present Value ($)	Benefit/Cost Ratio
TRC	686,032	2,133,572	1,447,540	3.11
UTC	1,867,916	2,036,250	168,334	1.09
RIM	3,520,180	2,036,250	(1,483,930)	0.58
PART	-	2,858,320	2,858,320	N/A
Detailed Results				
Benefits	TRC	UTC	RIM	PART
Avoided Costs	$ 2,133,572	$ 2,036,250	$ 2,036,250	
Bill Reduction				$ 1,652,264
Incentive Payments				$ 1,206,056
Total Benefits	$ 2,133,572	$ 2,036,250	$ 2,036,250	$ 2,858,320
Costs	TRC	UTC	RIM	PART
Program Administration	$ 110,677	$ 105,596	$ 105,596	
Participant Incentives	$ -	$ 1,206,056	$ 1,206,056	
Field Costs	$ 575,356	$ 556,264	$ 556,264	
Lost Revenues			$ 1,652,264	
Total Costs	$ 686,032	$ 1,867,916	$ 3,520,180	$ -