PUGET SOUND ENERGY

The Energy To Do Great Things

Avoided Cost Calculations for

Electric Energy Efficiency Programs

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Contents

1. Introduction

Puget Sound Energy's (PSE) avoided cost of electricity is used by the Energy Efficiency Department in the calculation of benefits for three of four cost-effectiveness tests. The tests that utilize PSE's avoided cost of electricity as benefits for the cost-effectiveness calculations include: the Utility Cost Test (UC), the Total Resource Cost Test (TRC), and the Ratepayer Impact Measure (RIM) Test. The fourth test, the Participant Cost Test (PCT), calculates benefits using customer bill savings, program incentives, and tax credits.

PSE calculates the avoided cost of electricity, which consists of two main components: the avoided cost of energy and the avoided cost of capacity. The avoided cost of energy and capacity are calculated for each year over the thirty year time period. The present value of the annual avoided cost are then included as a benefit in the relevant cost-effectiveness test. This range of costs allows PSE to assess measures that have a savings life ranging from one to thirty years

This paper provides the background assumptions and calculation of avoided costs used in PSE 2012-2013 cost-effectiveness calculations. The calculation of the avoided energy costs is explained in section two; the calculation of the avoided capacity costs is explained in section three. Section four provides details on how the avoided cost of energy and capacity are combined to calculate the total avoided cost of electricity.

2. Avoided Cost of Electric Energy

PSE calculated the 2012-2013 avoided cost of electricity for sixteen end-uses[i] which are representative of the measures PSE currently offers though energy efficiency programs. When calculating benefits for use in the cost-effectiveness tests, each measure is assigned to one of the sixteen end-uses which best fits the measure description. Since the value of the energy varies throughout the year, the avoided cost of energy is calculated separately for each of the sixteen representative end-uses to account for the variance in end-use and hence measure load shape.

Avoided energy cost is calculated using the following inputs:

1. Weighted average annual market price of electricity
2. Avoided line losses
3. Planning adjustment
4. Avoided incremental costs of compliance with renewable energy standards
5. Conservation credit (set to zero for the UC & RIM)

Each input to the calculation of the avoided cost of energy is described in the remainder of this section.

2.1. Weighted Average Annual Market Price of Energy

The first step in calculating avoided cost of energy was to calculate a weighted average annual market price for energy (WAAMPE) over the next thirty years. This price represents the average annual price PSE expects to pay to purchase energy from the market to serve the load which is being reduced though an energy efficiency technology.

To calculate the weighted average annual market price of energy, PSE used a combination of hourly market prices and hourly load shapes, for the 16 representative end-uses.

2.1.1 Hourly Load Shapes

Hourly load shapes for each of the 16 end-uses are provided as a distribution of one megawatt (MW) of energy over an entire year, providing the portion of that megawatt used in each hour throughout a typical year.[ii] Therefore, the sum of the hourly loads over 8,760 hours, for each of the end-uses, is one MWh.

2.1.2 Hourly Market Prices

Hourly market prices from the 2011 Integrated Resource Plan (IRP) were used in the estimation of the weighted average annual price of energy from 2012 through 2032. The 2011 IRP hourly market prices came from the most recent ARORA forecast.

2.1.3 Calculation

To PSE calculated the weighted average annual market price of energy for years 2012 through 2032, PSE energy efficiency evaluation staff obtained the hourly load shapes[iii] used in the 2011 IRP and the hourly market prices for electricity used in the 2011 IRP. The weighted average annual cost of energy was then calculated for each of the sixteen end-uses for each year 2012-2032.

Because hourly market prices in PSE's 2011 IRP only cover 21 of the 30 years required to perform the cost-effectiveness tests, further assumptions were required to project the prices to the end of the 30-year period. This was done by inflating the weighted average annual market price of energy in 2032 (the last year of the IRP projections) by the assumed long-run inflation rate in the IRP (2.5%).

The weighted average annual market price of energy is calculated for each year, by end-use, by summing the product of the hourly market energy prices, in year y, and hourly loads for each end-use.

The methodology for calculating the weighted average annual cost of energy for years 2012 through 2032, for each end-use, is summarized below:

$$WAAMPE_{j_y} = \sum_{h=1}^{8760} load_{j_h} * price_{h_y}$$

Where:

$load_{jh}$: Percent of one MW used in hour h for end-use j

$Price_{hy}$: Price of electricity in hour h of year y

$WAAMPE_{jy}$: Weighted average annual market price of electricity for end-use j in year y ($/MWh)

2.2. Avoided Cost of Line Losses

As energy is transmitted from a generation facility to a customer premise, a portion of this energy is lost. As a result, when PSE runs an efficiency program that saves energy at a customer's home, let's say one kilowatt-hour, PSE actually saves slightly more than one kilowatt during that hour. PSE avoids serving that house with one kilowatt during that hour and also avoids the line losses experienced while delivering that one kilowatt to the customer. To account for energy line losses in the 2012-2013 avoided cost calculations, a loss factor of 8.02% was applied to the weighted average annual market price of energy for residential programs; a loss factor of 6.55% was applied to the weighted average annual market price of energy for commercial and industrial programs.

The energy losses factors listed above include other forms of unmetered usage, in addition to the line losses that are of primary interest in PSE's cost-effectiveness calculations. Therefore, these loss factors slightly overestimate energy losses that are due solely to the transmission of energy across PSE's electric delivery system.

When AMR meters were installed in the majority of PSE service territory, PSE stopped tracking unmetered usage on an ongoing basis. Therefore, it is not possible to estimate this unmetered usage, subtract them from total loss, and estimate line loss based on that difference. Notwithstanding these deficiencies, PSE has included the total energy loss factor in the avoided cost calculations as a proxy for avoided line losses.

PSE recognizes that these losses may slightly overstate the benefits attributable to its energy efficiency programs. However, PSE believes these effects are minor and will work in the coming years to estimates of line losses.

2.2.1. Calculation of Avoided Cost of Line Losses (LL_{jy})

Residential Line $Loss_{jy}$ $WAAMPE_{jy} * 8.02\%$

Commercial/Industrial Line $Loss_{jy}$: $WAAMPE_{jy} * 6.55\%$

Where:

$WAAMPE_{jy}$: Weighted Average Annual Market Price of Energy for end-use j in year y

2.3 Planning Adjustment

The 2011 IRP provided guidance for an all market portfolio, adjusted for firm capacity needs and the renewable portfolio standards. Therefore, the planning adjustment for the 2012-2013 programs is simply the cost difference- which is not attributable to the market value of energy, the avoided capacity costs, or the avoided renewable portfolio standard costs- between the 2011 IRP portfolio with no demand side resources (DSR) and the 2011 IRP portfolio with optimal DSR. This is shown formulaically below.

Levelized Avoided Cost of Planning Adjustment:

$$PA = \frac{\sum_{y=1}^{20} [[(PNDSR_y - PWDSR_y) - (PNDSRC_y - PWDSRC_y) - (PNDSRR_y - PWDSRR_y) - (PNDSRE_y - PWDSRE_y)] / (1+I)^y]}{\sum_{y=1}^{20} [EnergySavings_y / (1+I)^y]}$$

Where:

PNDSR: Cost of the portfolio with no DSR

PWDSR: Cost of the portfolio with DSR

PNDSRC: Cost of peaking resources (capacity) in the portfolio with no DSR

PWDSRC: Cost of peaking resources (capacity) in the portfolio with DSR

PNDSRR: Cost of the renewable portfolio standards in the portfolio with no DSR

PWDSRR: Cost of the renewable portfolio standards in the portfolio with DSR

PNDSRE: Market price of energy in the portfolio with no DSR

PWDSRE: Market price of energy in the portfolio with DSR

I: Interest rate used for discounting, PSE ROR (8.10%).

$EnergySavings_{y}$: Energy Savings in year y from the portfolio with DSR

Because resources are built to meet demand over time, the value of the planning adjustment is calculated as a levelized[iv] payment over the life of the portfolio, which is 20 years. The levelized avoided cost of the planning adjustment, over the 20-year planning horizon in the 2011 IRP, is $0.23 per MWh. However, PSE cost-effectiveness calculations require avoided costs calculated over a 30 year planning horizon. For years 2032 through 2041, PSE held the nominal cost of the planning adjustment flat at $0.23 per MWh. The value of the planning adjustment does not change by end-use; it is a constant $0.23 per MWh for every end-use[v].

2.4 Avoided Cost of Renewable Portfolio Standard

Chapter 19.285 of the Revised Code of Washington (RCW)[vi] statutorily requires PSE to use "eligible" renewable resources, or acquire equivalent renewable energy credits (RECs), to meet annual renewable energy targets. PSE must use these renewable resources, RECs or some combination of the two to meet at least three percent of the load by January 1, 2012, and each year thereafter through December 31, 2015. That requirement grows to nine percent by January 1, 2016, and each year thereafter through December 31, 2019; and at least fifteen percent by January 1, 2020 and thereafter.

As suggested above, the size of PSE's renewable portfolio is dependent upon the amount of energy required to serve customers. In as much as energy efficiency programs reduce the energy requirements of PSE's customers, the need for PSE to purchase renewable energy also shrinks. Therefore, the cost of meeting this renewable portfolio standard that is avoided due to energy efficiency activities needs to be accounted for in PSE's avoided costs for energy.

Because the IRP is a 20-year plan, the avoided cost of the renewable portfolio standard is first calculated as a levelized payment over 20 years. Based on the assumptions in the 2011 IRP, that levelized payment is currently $11.49 per MWh. For years 2032 through 2041, PSE held the avoided cost of the renewable portfolio standard flat, at a nominal rate of $11.49 per MWh. For purposes of calculating cost-effectiveness, the value for the avoided cost of PSE's renewable energy standard is assumed to not change by end-use. The basic formula used in these calculations is shown below.

Levelized Avoided Cost of Renewable Portfolio Standard:

$$RPSC = \frac{\sum_{y=1}^{20}[(PNDSRR_y - PWDSRR_y)/(1+I)^y]}{\sum_{y=1}^{20}[EnergySavings_y/(1+I)^y]} = \$11.49/MWh$$

Where:

PNDSRR: Cost of renewable energy standards from the portfolio with no DSR

PWDSRR: Cost of renewable energy standards from the portfolio with DSR

I: Interest rate used for discounting, PSE ROR (8.10%).

$\text{EnergySavings}_{y:}$ Energy savings in year y from the portfolio with DSR

PSE's statutory renewable portfolio requirements can be viewed with the following link:

http://apps.leg.wa.gov/rcw/default.aspx?cite=19.285.040

2.5 Conservation Credit for Energy

Section 3(4)(D) of the Pacific Northwest Electric Power Planning and Conservation Act ("NW Power Act") directs the Northwest Power and Conservation Council, and the Bonneville Power Authority, to apply a 10 percent cost advantage to conservation when comparing it with sources of electric generation. The Northwest Power and Conservation Council applies this cost credit to the value of market prices, deferred transmission and distribution investments, and risk avoidance in the formulation of their periodic Regional Power Plans. Further Section 1(a) of RCW 19.285.040 requires PSE to use a methodology "consistent" with that outlined in the NW Power Act when evaluating relative merits of demand-side resource vs. supply-side alternatives.

PSE applies this cost advantage to conservation only in the calculation of avoided electric cost for the TRC test. Specifically, the avoided cost of market priced energy, the line loss reductions, the planning adjustment, and the avoided cost of renewable standards are all increased by 10%.

Conservation Credit for Energy: $CCE_{j_y} = (WAAMP_{j_y} + PA + RPSC + LL_{jy}) * 0.10$

Where:

$CCE_{jy:}$ Conservation Credit for Energy for end use j in year y

$WAAMPE_{jy}$: Weighted Average Annual Market Price of Energy for end-use j in year y

LL_{jy}: Avoided cost of line loss

PA: Levelized value of the planning adjustment

RPSC: Levelized value of the renewable portfolio standard costs

2.6 Calculation of Avoided Cost of Energy

Within the cost-effectiveness tests, the avoided cost of energy is calculated as the present value of the stream of avoided costs, over the life of the measure being assessed. Obtaining the value of avoided costs in a present value is essential in producing valuable benefit-cost ratios because it allows an apples-to-apples comparison of the benefits (avoided costs) of a program, or measure, with the costs associated with obtaining those benefits, typically incurred in the first year of the measure installation.

PSE calculated the present value (in 2012 dollars) of the stream of avoided costs using the total avoided cost of energy, for years 2012 through 2041. Once the present value of avoided costs (for years 2012 through 2041) are known, PSE can calculate the present value of the stream of avoided costs for various measure lives.

2.6.1 Avoided Cost of Energy for years 2012 through 2041

The total avoided cost of energy, for years 2012 through 2041, are calculated by summing the values for the weighted average annual market price, the value of line losses, the planning adjustment, the avoided cost associated with PSE's renewable portfolio standards, and the conservation credit. The total yearly avoided cost of energy is defined below:

$$TCE_{j_y} = WAAMPE_{j_y} + LL_{j_y} + PA_y + RPSC_y + CC_{j_y}$$

Where:

$TCE_{jy:}$ Total avoided cost of energy for end-use j in year y

$WAAMPE_{jy}$: Weighted average annual market price of energy for end-use j in year y

LL_{jy}: Line losses for end-use j in year y

PA_y: Value of the planning adjustment in year y ($0.23/MWh)

$RPSC_y$: Value of the avoided cost associated with renewable portfolio standard in year y ($11.49/MWh)

CC_{jy}: Value of the conservation credit for end-use j in year y. This is set to zero for the Utility Cost Test and the RIM Test.

2.6.2 Present Value of Avoided Cost of Energy

Once the total avoided cost of energy, for years 2012 through 2041, are calculated, the present value of the avoided cost of energy are calculated in 2012 dollars.

PSE uses its authorized rate of return on rate base (ROR) of 8.1% as the discount rate in its present value calculations. This rate was approved in PSE's 2009 General Rate Case and was used in its 2011 IRP[vii].

The present value of the avoided cost of energy is defined below:

$$PV_{j_y} = TCE_{j_y} \Big/ (1+I)^y$$

Where:

PV_{j_y} : Present value of year y's avoided costs of energy for end-use j.

TCE_{j_y} : Total avoided cost of energy for end-use j in year y.

I: Interest rate used for discounting, PSE's ROR (8.10%).

2.6.3 Present Value of the Stream of Avoided Energy Costs

The present value of the stream of avoided energy costs is equal to the total benefits of avoided energy costs over the life of the measure being assessed. The present value of the stream of avoided costs are calculated for years 2012 through 2041 and are equal to the sum of avoided costs for each year, y, and all years previous. The calculation of the present value of the stream of avoided costs is below:

$$PVSACE_{j\,y} = \sum_{y=1}^{N} TCE_{j_y} \,/ (1+I)^y$$

Where:

$PVSACE_{jy}$: Present value of the stream of avoided costs for a measure with end-use j and a savings life of y.

TCE_{j_y} : Total avoided cost of energy for end-use j in year y.

I: Interest rate used for discounting, PSE's ROR (8.10%).

N: Measure Life

3. Avoided Cost of Capacity

PSE's peak load (highest load of the year) is expected to increase over time. As peak loads increase, PSE incurs a cost to build resources which are specifically attained to assist the company in meeting the energy demands of customers during the peak hour. In addition to the costs of the peaking resources, PSE incurs a cost to upgrade the current transmission and distribution system so that it can handle the larger peak loads.

A portfolio with DSR, which saves energy on the peak hour, will assist the utility in avoiding the purchase of some peaking resources. The portfolio with DSR will also assist in deferring some of the transmission and distribution system upgrades. When calculating the avoided cost of energy efficiency activities, it's important to include the avoided costs of capacity which occur because of the investment in energy efficiency resources.

The avoided costs of capacity are added to the avoided cost of energy when calculating the benefits for energy efficiency measures and programs. The avoided costs of capacity are quantified by kW-yr, unlike the avoided cost of energy which is in units of megawatt hour of energy. Therefore, for each end-use in the efficiency portfolio, the value of capacity (or kW) is multiplied by the percent of total load, for end-use j, which occur on the peak hour per the end-use load shape[viii].

When calculating the benefits for the TRC, a 10% conservation credit is applied to the fixed cost of capacity and the deferred transmission and distribution costs.

Avoided capacity cost is calculated using the following inputs:

1. Fixed cost of capacity
2. Avoided cost of transmission and distribution
3. Conservation credit (set to zero for the UC & RIM)

3.1 Fixed Capacity Costs

The avoided fixed capacity cost are calculated as an annual payment, over twenty years, on the difference in fixed capacity costs (cost of building peaking resources) between the portfolio with no demand side resources and the portfolio with optimal demand side resources, on a per KW-year basis. The levelized value, per KW-year, is currently $202.15.

$$FCC = \frac{\sum_{y=1}^{20} [(PNDSRC_y - PWDSRC_y) / (1+I)^y]}{\sum_{y=1}^{20} [PeakBuilds_y / (1+I)^y]}$$

Where:

FCC: Fixed Cost of Capacity

PNDSRC: Cost of peaking resources (capacity) in the portfolio with no DSR

PWDSRC: Cost of peaking resources (capacity) in the portfolio with DSR

Peak Builds: The megawatts of peaking resources built in year y under the optimal portfolio with DSR.

For years 21 through 30, PSE held the avoided fixed cost of capacity flat at $202.15 per megawatt KW-year.

3.2 Avoided Cost of Transmission and Distribution Costs

Currently, PSE uses the value of avoided transmission and distribution from the 6th Northwest Power Plan. The plan used monetary values of avoided transmission and distribution capacity which were recommended by the Regional Technical Forum. The value recommended for avoided transmission is $23 per kW-year; the value recommended for avoided distribution is $25 per kW-year.

The values of transmission and distribution in the 6th Northwest Power Plan are in 2006 prices. To obtain a value for 2012, the price in 2006 was inflated using Moody Analytics full CPI from 2006 to 2012. The reason the assumed inflation rate in the IRP was not used is because past inflation values are known and the assumed inflation rate in the IRP is an assumed future inflation rate.

The combined value of avoided transmission and distribution is $54.32 per kW-year in 2012 dollars. The 2012 value of transmission and distribution was inflated by the assumed inflation rate in the IRP of 2.5% to obtain avoided transmission and distribution costs for years 2013 through 2041.

$$TD_y = (TD_{(y-1)} * 1.025)$$

Where:

TD_y: Avoided cost of transmission and distribution for end-use j in year y.

3.3 Conservation Credit for Capacity

Section 3(4)(D) of the Pacific Northwest Electric Power Planning and Conservation Act ("NW Power Act") directs the Northwest Power and Conservation Council, and the Bonneville Power Authority, to apply a 10 percent cost advantage to conservation when comparing it with sources of electric generation. The Northwest Power and Conservation Council applies this cost credit to the value of market prices, deferred transmission and distribution investments, and risk avoidance in the formulation of their periodic Regional Power Plans. Further Section 1(a) of RCW 19.285.040 requires PSE to use a methodology "consistent" with that outlined in the NW Power Act when evaluating relative merits of demand-side resource vs. supply-side alternatives.

PSE applies this cost advantage to conservation only in the calculation of avoided electric cost for the TRC test. Specifically, the avoided cost of market priced energy, the line loss reductions, the planning adjustment, and the avoided cost of renewable standards are all increased by 10%. This cost advantage is not applied to the UC, RIM, or PCT.

Conservation Credit for Energy:

$$CCC_y = \left(FCC + TD_y\right) \times 0.10$$

Where:

$CCC_{y:}$ Conservation Credit for Capacity in year y

FCC: Fixed cost of capacity

TD_y: Avoided cost of transmission and distribution for end-use j in year y.

3.4 Calculation of Avoided Cost of Capacity

The avoided cost of capacity is calculated as the present value of the stream of avoided capacity cost over the life of the measure being assessed. This means that PSE must calculate the present value of the stream of avoided capacity costs for years 2012 though years 2041.

The present value of the stream of avoided capacity costs in each year contains the present value of avoided capacity cost in that year and in every year previous. To calculate the present value of the stream of avoided capacity costs, PSE first calculates the nominal avoided cost of capacity for each year, 2012-2041. PSE then obtains a present value of avoided cost of capacity for each year, for years 2012 through 2041, in 2012 dollars. After calculating the present value per year, PSE calculates the stream of avoided costs by summing the present value of avoided costs for each year, y, and every year previous.

3.4.1 Calculation of the Total Avoided Cost of Capacity

The total avoided cost of capacity is calculated by summing the values for fixed capacity costs, avoided cost of transmission and distribution, and the conservation credit.

$TCC_y = (FCC_y + TD_y + CCCy)$

Where:

$TCC_{y:}$ Total avoided cost of capacity in year y

FCC_y: Avoided Fixed Capacity Cost in year y

TD_y: Avoided Transmission and distribution

CCC_y: Conservation Credit in year y. This value is set to zero for the Utility Cost Test and the Ratepayer Impact Measure Test

3.4.2 Present Value of Avoided Cost of Capacity

Once the total avoided cost of capacity (for years 2012 through 2041) is calculated, the present value of the avoided cost of capacity, for year 2012 though 2041, is obtained. The present value is calculated to set all avoided costs to 2012 dollar values. All dollar values need to be in the same time period so correct comparisons of benefits and costs can be made.

For present value calculations, PSE's weighted average cost of capital (8.1%) is used as the discount rate. This rate is adopted from the commission-approved cost of capital structure from the 2009 General Rate Case and is utilized in the 2011 IRP[ix].

Present value calculations are defined below:

$$PVSACC_{j_y} = (TCC_{j_y})/(1+I)^y$$

Where:

PV_y : Present value of year y's avoided costs of energy for

$TCC_{y:}$ Total avoided cost of capacity in year y

I: Interest rate used for discounting, PSE weighted average annual cost of capital (8.10%).

3.4.3 Present Value of the Stream of Avoided Capacity Costs

The present value of the stream of avoided capacity costs is equal to the total benefits of avoided capacity costs over the life of the measure being assessed. The present value of the stream of avoided costs are calculated for years 2012 through 2041 and are equal to the sum of avoided costs for each year, y, and all years previous. The calculation of the present value of the stream of avoided costs is below:

$$PVSACC_{j_y} = \sum_{y=1}^{N} [[(TCC_{j_y})/(1+I)^y]*(LPH_j)]$$

Where:

$PVSACC_y$: Present value of the stream of avoided costs for a measure and a savings life of y.

TCC_y: Total avoided cost of capacity in year y

I: Interest rate used for discounting, PSE weighted average annual cost of capital (8.10%).

LPH_j: Percent of total load on the peak hour for end-use j

N: Measure Life

4. Total Avoided Cost of Electric Energy (Energy and Capacity)

The present value of the stream of avoided costs of electricity (energy and capacity) is calculated by summing the capacity and energy components. This value is then utilized in the benefit-cost assessments in EES.

The calculation of the present value of the stream of avoided costs for electricity (energy and capacity) is provided below:

$$PVSACTE_j = \sum_{i=1}^{N}[TCE_{j_y} /(1+I)^y] + [[TCC_{j_y} \big/ (1+I)^y]*LPH_j]$$

Where:

$PVSACTE_j$: Present value of the stream of total avoided costs for a measure and a savings life of y.

N: Measure Life

[i] End-use is a word used to describe the common uses of energy associated with a particular sector. For example, for the residential sector, water heating, space heating, lighting, and refrigeration are all end-use categories.

[ii] Load shapes were developed for a 365 day (8760 hour) year, not a leap year.

[iii] The majority of load shapes are derived from Energy 10 building simulations or adopted from the Northwest Power and Conservation Council. All load shapes used in the avoided cost calculations are obtained from CADMUS, the firm which completes PSE's IRP.

[iv] The planning adjustment was calculated as a levelized payment because resources are not built at continuous points in time as they are needed. Resources are built intermittently to meet future loads. Therefore, a levelized value was appropriate. This avoids the entire planning adjustment arbitrarily inflating the value of avoided costs only in certain years.

[v] To accurately estimate the planning adjustment in years 21 through 30, PSE would need information on the resource needs and resource costs in those periods of time. Because they are unknown, we assume the payment will stay flat over 30 years.

[vi] Sometimes referred to as the "Energy Independence Act" or "I-937."

[vii] Each time avoided costs are updated, the analyst conducting the analysis is required to update the discount rate to reflect the rate used in the most recent IRP. This rate should also correlate to the most recent commission-approved cost of capital before the finalization of the IRP. The Resource Planning Group provides the base WAACC for the most recent IRP. To obtain a breakout of the WACC for equity, long-term debt, and short-term debt, speak with the Manager of the Cost of Service in the Rates Department, currently Jon Piliaris.

[viii] Peak hour is defined in the 2011 IRP as the average load of the six hours ending at 7am to 12pm and the six hours ending at 6pm to 11pm on weekdays in December. Because load shapes obtained from Cadmus are labeled in 2005 dates, the calendar for 2005 was used to estimate average load in peak hour.

[ix] Each time avoided costs are updated, the analyst conducting the analysis is required to update the discount rate to reflect the rate used in the most recent IRP. This rate should also correlate to the most recent commission-approved cost of capital before the finalization of the IRP. The Resource Planning Group provides the base WAACC for the most recent IRP. To obtain a breakout of the WACC for equity, long-term debt, and short-term debt, speak with the Manager of the Cost of Service in the Rates Department, currently Jon Piliaris.

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1. Introduction

Avoided costs of natural gas are calculated for six end-uses, which are representative of the measures offered through Energy Efficiency Services (EES) programs. The avoided costs of natural gas are calculated on an annual basis before being converted in a present value for inclusion in the benefit-cost assessments.

Because the measures offered by EES save energy at different times throughout the year, the avoided costs of natural gas are calculated separately for each of the six representative end-uses. Not only do energy costs vary through the year[i], making the avoided costs dependent upon the timing of savings, but measures which save energy on the peak day avoid additional pipeline demand charges and distribution capacity costs.

Total avoided costs of natural gas are calculated using the following inputs:

1. Weighted average annual market prices of natural gas
2. Avoided pipeline demand charge
3. Avoided pipeline variable transportation charge
4. Avoided pipeline fuel reimbursement charge
5. Avoided distribution capacity costs

Unlike the avoided cost of electricity, there are no regulatory guidelines on applying the conservation credit to natural gas costs. Therefore to be consistant with the 2011 IRP, Puget Sound Energy (PSE) did not apply the conservation credit to the avoided costs of natural gas.

2. Weighted Market Price of Natural Gas

To calculate the weighted average annual market price of gas for years 2012 through 2041, PSE calculated the weighted average annual market price of natural gas over the years 2012 through 2031, for each of the six representative end-uses. PSE then inflated the price in year 2031 by 2.5%[ii] to estimate a weighted average annual market price of natural gas for years 2032 through 2041.

To calculate the weighted average annual market price of natural gas for years 2012 through 2031, the estimated average monthly natural gas prices[iii] and the monthly gas load shapes[iv] were obtained from the 2011 IRP. To obtain a weighted average annual price of natural gas for all six representative end-uses, the sum of the product of the monthly Sumas prices and the load shapes were calculated.

Calculation

For year 2012 though year 2031:

$$WAAMPG_{j_y} = \sum_{m=1}^{12} (load_{j_m}) * (price_{m_y})$$

Where:

$load_{jm}$: Percent of one therm used in month m for end-use j

$Price_{hy}$: Price of natural gas in month m of year y

$WAAMPG_{jy}$: Weighted average annual price of gas for end-use j in year y

3. Avoided Pipeline Demand Charge

The inclusion of a pipeline demand charge in avoided costs of natural gas is to account for potential avoided contract costs with the Northwest Pipeline. These contract costs are paid to reserve pipeline capacity for peak demand. When there is large demand for natural gas, PSE first utilizes the natural gas in PSE owned storage facilities and other available PSE peaking resources. However, to the extent that PSE's demand at peak outweighs PSE's ability to meet that demand with current peaking resources, PSE must buy gas from other sources.

Because PSE purchases natural gas from sources which are not directly connected to the PSE owned distribution systems, PSE has to purchase pipeline capacity from the Northwest Pipeline so that natural gas can be moved from the point of purchase (typically Sumas) to PSE owned pipes. When PSE buys capacity on the Northwest Pipeline, PSE reserves the capacity year around. Therefore, each year PSE purchases enough capacity to meet forecasted peak demand. Capacity is paid on a per day charge, year-round, even on days when PSE does not need the full amount of reserved capacity on the pipeline.

To the extent that gas efficiency programs mitigate peak demand, the efficiency programs assist PSE in avoiding some of the pipeline capacity costs. A portion of the pipeline capacity costs are avoided because PSE can purchase a smaller amount of capacity on the Northwest Pipeline when energy efficiency programs reduce peak demand.

The 2011 IRP indicates that PSE has enough capacity on the Northwest Pipeline to meet future demands though 2015. In 2016, PSE will need to begin purchasing additional capacity on the pipeline at $0.45 per dekatherm of capacity per day, or $164.25 per year, per dekatherm of capacity.

In 2017, the cost per dekatherm on the pipeline will increase by five percent, costing PSE $0.4725 per dekatherm of capacity per day, or $172.4625 per year, per dekatherm of capacity. That cost will remain flat for the five year contract and will increase by five percent every five years.

3.1. Calculation of Estimated Peak Savings by end-use

Because load shapes for the natural gas end-uses are not provided on a daily basis, PSE must estimate peak savings for each end-use, j, by multiplying the inverse of the load factor of end use j by the average load of end-use j. The explanation of the load factor, along with the calculation, is explained in sections 3.1.1 and 3.1.2.

PSE calculated peak savings with two different methodologies. For weather-sensitive end-uses, PSE used the gas forecast to estimate the load factor. For non-weather-sensitive end-uses, PSE utilized individual end-use load shapes to estimate the load factor.

An alternative option to estimate the load factor for weather-sensitive end-uses would be to utilize the individual load shapes, making the calculation of load factors for weather-sensitive measures consistent with the methodology used to calculate load factors for non-weather-sensitive measures. However, the PSE avoided cost team believed that a better estimate of load factor would be derived if the forecast was used.

It is not possible to use the forecast information to estimate the load factor for non-weather-sensitive loads (end-uses) unless the analyst assumed loads for non-weather-sensitive end-uses are completely flat. Therefore individual load shapes for non-weather-sensitive end-uses were used to estimate the load factor for those end-uses.

3.1.1. Peak savings for weather sensitive end-uses

To calculate the percentage of savings which occur coincident with system peak, the analyst first estimated a load factor, which is simply the average daily load for weather sensitive end-uses divided by the load of weather sensitive end-uses on peak day by customer class (residential or non-residential).

The load factor is defined below:

$$LF_c = ADLW_c / PDLW_c$$

Where:

LF_c: Load factor for customer class c, either residential or non residential

$ADLW_c$: Average daily load for weather sensitive end-uses for customer class c

$PDLW_c$: Peak day load for weather sensitive end-uses for customer class c

Next, the inverse of that load factor, which provides a percent of the average daily load which occurs on peak day, is multiplied by the average daily load for weather sensitive measures (one dekatherm spread evenly over a year) to obtain peak demand savings.

Estimated peak savings are defined below:

$$PDSW_c = [(PDLW_c)/(ADLW_c)] * (1/365) \quad \text{OR} \quad PDSW_c = (1/LF_c) * (1/365)$$

Where:

PDSWc: Peak savings, percent of weather sensitive load which occurs on peak day for class c (residential or non-residential)

PDLWc: Peak day load for weather sensitive end-uses in customer class c

ADLWc: Average daily load for weather sensitive end-uses in customer class c

The peak savings is then multiplied by the yearly demand charge to obtain the avoided cost of pipeline demand charges for end-use j in year y.

The peak demand charge is defined below:

$$PDC_{j_y} = (PDSW_{j_c}) * (PDC_y)$$

Where:

PDC_{jy}: Avoided pipeline demand charge for end-use j in year y.

$PDSW_{jc}$: Peak demand savings for weather-sensitive end-use j in customer class c

PDC_y: Avoided pipeline demand charge for year y

3.1.2. Calculation of peak savings for non-weather sensitive loads

For non-weather sensitive loads, peak savings were calculated by estimating a percent of one dekatherm of savings which occurs on peak, using individual end-use load shapes; not using the gas forecast.

To calculate this percentage, the load factor is calculated as the average daily load for the non-weather sensitive end-use, j, divided by the peak load of end-use j.

The load factor is defined below:

$$LF_j = ADLNW_j / PDLNW_j$$

Where:

LF_j: Load Factor for end-use j

$ADLNW_j$: Average daily load for non-weather sensitive end-use j

$PDLNW_j$: Peak day load for non-weather sensitive end-use j

Next, the inverse of that load factor is calculated to provide a percent of the average daily load which occurs on peak day, for end-use j. This percentage is multiplied by the average daily load for end-use j (one dekatherm spread over a year) to obtain peak demand savings.

Peak savings are defined below:

$$PDSNW_j = [(PDLNW_j)/(ADLNW_j)]*(1/365) \text{ OR } PDSNW_j = (1/LF_j)*(1/365)$$

Where:

$PDSNW_j$: Peak savings for non-weather sensitive, percent of load for end-use j, which occurs on the peak day for end-use j.

$PDLNW_j$: Peak day load for non-weather sensitive end-use j.

$ADLNW_j$: Average daily load for non-weather sensitive end-use j.

The peak savings is then multiplied by the yearly demand charge to obtain the avoided cost of pipeline demand charges for end-use j in year y.

$$PDC_{j_y} = (PDSNW_j)*(PDC_y)$$

Where:

PDC_{jy}: Avoided pipeline demand charge for end-use j in year y.

$PDSNW_j$: Peak savings for non-weather sensitive end-use j

PDC_y: Pipeline demand charge for year y

4. Avoided Pipeline Variable Transportation Charge

The avoided pipeline variable transportation charge, which is included in the avoided cost calculations, represents the operation and maintenance costs on the pipeline. These costs vary by volume of flow on the pipeline, and the costs are independent of the time of flow. That current charge is $0.0319 per dekatherm. When PSE saves a dekatherm of gas at a customer location, PSE avoids paying the pipeline variable transportation charge on that dekatherm of gas.

Because the charge of $0.0319 per dekatherm is spent for every dekatherm of gas, the avoided pipeline variable transportation charge does not vary by end-use. In addition, the price is held constant over the course of the 30 year timeframe for avoided cost calculations. The charge is a negotiated charge and, at the time of the 2012-2013 avoided cost calculations, it was presumed that the majority of suppliers would lobby to hold this cost constant for the foreseeable future. Therefore, it is held constant for all years in the avoided cost calculations.

5. Pipeline Fuel Reimbursement

The avoided costs of pipeline fuel reimbursement are included in the avoided cost calculations to account for the additional savings on the fuel used by the compressors which move natural gas though the pipelines. As natural gas moves though the pipeline system, a small portion of the natural gas is consumed as fuel for the compressor systems that move the natural gas from various points in the pipeline. The pipeline reimbursement rates vary every 6 months, but generally range in the 2-3%. PSE applied a 2.9 %[v] rate for fuel reimbursement when calculating the 2012-2013 avoided costs.

Every time a PSE program saves a dekatherm of natural gas at a PSE customer location, PSE avoids both purchasing that unit of natural gas and purchasing additional 2.9% of that unit to fuel the compressors which move that natural gas to the customer location.

Calculation of Pipeline fuel reimbursement charge

$$PFRC_{j_y} = WAAMPG_{j_y} * 0.029$$

Where:

$PFRC_{jy}$: Avoided Pipeline Fuel Reimbursement charge for end-use j in year y.

6. Deferred Distribution Capacity Cost

The deferred pipeline distribution capacity cost is included in the calculations of the avoided cost of natural gas to account for the deferred cost of pipeline reinforcements. When peak demand increases, pipelines need to be reinforced to support the additional flow of natural gas. In as much as energy efficiency projects reduce peak demand, PSE can defer pipeline reinforcement projects.

The 2010 gas utilization business case was used to estimate the cost of pipeline reinforcements in years 2012 through 2041. The 2010 business case estimated a cost of $9,650,000 (high and intermediate pressure projects) would be spent from the capital budget for each 1% of load growth.

Upon receiving a cost estimate for distribution capacity projects in 2010 dollars, the PSE analyst estimated project costs though 2041 by inflating the cost in the year previous by 2.5%[vi] .

Because the reinforcement costs on a pipeline are a onetime cost- and those costs are simply differed, not necessarily avoided by EES programs-the yearly avoided costs of pipeline distribution capacity costs are represented as an avoided payment, or the yearly value of a levelized cost. The levelized payments were calculated over a 35 year timeframe as advised by the gas planning group. At the time the 2012-2013 avoided costs were calculated, the gas planning group believed that 35 years was the best estimate for the life of distribution upgrades. Each year 2012 though 2041 has a unique deferred payment, which is based on the payment for that year's estimated distribution capacity costs.

7. Calculation of Avoided Cost of Natural Gas

For inclusion in the benefit cost calculations, the avoided cost of natural gas is calculated as the present value of the stream of avoided cost over the life of the measure being assessed. The present value of the stream of avoided costs in each year contains the present value of avoided cost in that year and in every year previous. To calculate the present value of the stream of avoided costs, PSE first calculates the nominal avoided cost of energy for each year, 2012 though 2041.

Upon completion of the nominal cost calculations, PSE obtains a present value of avoided cost for each year, y, in 2012 dollars. After calculating the present value per year, PSE calculates the stream of avoided costs by summing the present value of avoided costs for each year, y, and every year previous. All present value costs are in calculated to the beginning of year 2012.

7.1. Nominal Avoided Cost of Natural Gas

The nominal avoided cost of natural gas is calculated by summing the values for the weighted average annual market price, the value of the pipeline distribution charge, the pipeline variable transportation charge, the pipeline fuel reimbursement charge, and the deferred value of the distribution capacity cost.

The nominal avoided cost of natural gas is defined below:

$$TCG_{j_y} = WAAMPG_{j_y} + PDC_{j_y} + PVTC + PFRC_{j_y} + DCC_{j_y}$$

Where:

TCG_{jy}: Total nominal avoided cost of natural gas for end-use j in year y.

$WAAMPG_{jy}$: Weighted average annual market price of natural gas for end-use j in year y.

PDC_{jy}: Avoided pipeline demand charge for end-use j in year y.

PVTC: Pipeline variable transportation charge, which is constant for all years and end-use types.

$PFRC_{jy}$: Pipeline fuel reimbursement charge for end-use j in year y.

DCC_{jy}: Avoided cost of distribution capacity

7.2 Present Value of Avoided Cost of Natural Gas

Once the nominal avoided cost of natural gas are calculated, for years 2012 through 2041, the present value of the avoided cost of natural gas, for year 2012 though 2041, are obtained. The present value is calculated to set all avoided costs to 2012 dollar values. All dollar values need to be in the same time period so correct comparisons of costs can be made. For present value calculations, PSE's weighted average annual cost of capital (WACC) is used as the discount rate. The WACC is currently 8.1%. This rate is adopted from the commission-approved cost of capital structure from the 2009 General Rate Case and is utilized in the 2011 IRP[vii].

The present value of the total avoided cost of natural is defined below:

$$PVG_{j_y} = TCG_{j_y} \big/ (1+I)^y$$

Where:

PVG_{jy} : Present value of year y's avoided costs of energy for end-use j.

TCG_{jy}: Total avoided cost of energy for end-use j in year y.

I: Interest rate used for discounting, PSE weighted average annual cost of capital (8.10%).

7.2. Present Value of the Stream of Avoided Costs of Natural Gas

The present value of the stream of avoided costs is important in calculating the total benefits of avoided costs of natural gas over the life of the measure being assessed. The present value of the stream of avoided costs are calculated for years 2012 through 2041for the life of the measure and are equal to the sum of avoided costs for each year, y, and all years previous.

The calculation of the present value of the stream of avoided costs is below:

$$PVSACG_j = \sum_{y=1}^{N} TCG_{j_y} \big/ (1+I)^y$$

Where:

$PVTACG_j$: Present value of the avoided

TCG_{jy}: Total avoided cost of natural gas for end-use j in year y.

I: Interest rate used for discounting money, PSE weighted average annual cost of capital (8.10%).

N: Measure life

I. PSE assumes the load shape for energy savings is identical to the load shape of the end-use.

[II] 2.5% is the assumed inflation rate in the 2011 IRP.

[iii] Market Prices:_For the 2012-2013 Avoided Costs calculations, the estimated monthly market prices of natural gas, from Sumas, were used as a base to calculate a weighted average annual price of natural gas. Monthly gas prices were only available though 2031A.D. The estimated Sumas prices are contained in *Appendix B6*.

[iv] Load shapes:_Natural gas monthly load shapes, for the six end-uses, are provided as a distribution of one therm of natural gas over an entire year, which provides the portion of therm used in each month throughout a typical year. Therefore, the sum of each of the load shapes is one. The Load shapes used in the most recent IRP are contained in *Appendix B6***.**

[v] This percentage was based on recommendations from Bill Donahue- PSE Manager, Natural Gas Resources.

[vi] 2.5% was used as a price inflator because it is the assumed inflation rate in the IRP.

[vii] Each time avoided costs are updated, the analyst conducting the analysis is required to update the discount rate to reflect the rate used in the most recent IRP. This rate should also correlate to the most recent commission-approved cost of capital before the finalization of the IRP. The Resource Planning Group provides the base WACC for the most recent IRP. To obtain a breakout of the WACC for equity, long-term debt, and short-term debt, speak with the Manager of the Cost of Service in the Rates Department, currently Jon Piliaris.

PUGET SOUND ENERGY
The Energy To Do Great Things

Calculating the Cost-Effectiveness of Puget Sound Energy's Energy Efficiency Programs

July 2011

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Contents

1. Introduction

1.1. Background

Puget Sound Energy (PSE) has been providing energy efficiency services since the late 1970's and PSE will continue to deliver these services for the foreseeable future. With increasing customer demand for energy, PSE must acquire new resources to meet the needs of our customers over time. Every two years, PSE goes through a process of planning how it will meet expected customer demands over the next twenty years. Though this process, PSE compiles its Integrated Resource Plan (IRP). This plan provides guidance to assist PSE in selecting resources to meet expected energy demands.

Demand side resources (i.e. Energy Efficiency) are some of the cheapest ways for PSE to meet expected customer demand. When selecting which demand side resources to obtain, PSE conducts a series of tests which will assist PSE in determining which demand side resources to acquire compared to the alternative resources available.

Currently, PSE conducts four cost-effectiveness tests; two of the tests, the Utility Cost Test and the Total Resource Cost Test, are primarily of interest in the selection of demand side resources. Each of the four tests views cost-effectiveness from a slighting different perspective. The four tests PSE conducts are: Utility Cost Test (UC), Total Resource Cost Test (TRC), Ratepayer Impact Measurement Test (RIM), and the Participant Cost Test (PCT). These tests measure whether or not the benefits obtained by the demand side resource exceed the costs to obtain the resource.

How these tests are calculated can dramatically impact which demand side resources PSE obtains, whether or not the resources have a positive or negative impact on future customer rates, and if the resources save money for the customers who install items though our demand side resource programs.

1.2. Agreed Conditions

AGREED CONDITIONS FOR APPROVAL OF PUGET SOUND ENERGY, INC.'S 2010-2011 BIENNIAL ELECTRIC CONSERVATION TARGETS UNDER RCW 19.285. DOCKET NO. UE-100177

K. Conditions

(10) **Cost-Effectiveness Test is the Total Resource Cost (TRC) Test**

(a) The Commission uses the TRC, as modified by the Council, as its primary cost-effectiveness test. PSE's portfolio must pass the TRC test. In general, each program shall be designed to be cost-effective as measured by this test. PSE must demonstrate that the cost-effectiveness tests presented in support of its programs and portfolio are in compliance with the cost-effectiveness definition (RCW 80.52.030(7)) and system cost definition (RCW 80.52.030(8)) and incorporate, quantifiable non-energy benefits, the 10 percent conservation benefit and a risk adder consistent with the Council's approach. An outline of the major elements of the Council's methodology for determining achievable conservation potential, including the Total Resource Cost test, is available on the Council's website at http://www.nwcouncil.org/energy/powerplan/6/supplycurves/I937/CouncilMethodology_outline%20_2_.pdf.

(b) In addition to the Council-modified TRC, PSE must provide portfolio calculations of the Program Administrator Cost test (also called the Utility Cost test), Ratepayer Impact Measure test, and Participant Cost test described in the National Action Plan for Energy Efficiency's study "Understanding Cost-effectiveness of Energy Efficiency Programs." The study is available on the Web site of the United States Environmental Protection Agency at http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf.

(c) Overall conservation cost-effectiveness must be evaluated at the portfolio level. Costs included in the portfolio level analysis include conservation-related administrative costs. For the additional cost-effectiveness tests identified in 10b - PSE must consult with the CRAG to determine when it is appropriate to evaluate measure and program level cost-effectiveness. All cost-effectiveness calculations will assume a Net-to-Gross ratio of 1.0, consistent with the Council's methodology.

2. Overview of Cost-Effectiveness Tests

2.1. Introduction

The four cost-effectiveness tests discussed in this chapter each provide a unique set of information to assist different stakeholders in understanding if the investment in demand side resources is of an overall benefit to them.

At a very basic level, cost-effectiveness tests are performed by calculating the ratio of the net present value of benefits (in dollars) to the net present value of costs.

NPV $\sum$ benefits ÷ NPV $\sum$ costs

Holding all other factors constant, energy efficiency programs which have a benefit-cost ratio greater than one are in the best interest of the stakeholder for whom the ratio was calculated.

2.2. Utility Cost Test

The UC views demand side resource acquisition from the utility's perspective. This test is required for both gas and electric conservation programs. This test determines, from the utility's perspective, whether it is cheaper to purchase the demand side resource than it is to purchase an alternative supply side resource, like building a power plant or purchasing energy off of the open market.

Generally speaking, a benefit-cost ratio of one or greater in the UC is essential for a program to be considered in a demand side resource portfolio. However, there are some exceptions to this rule. State regulations currently allow PSE to run low-income weatherization programs that have a benefit-cost ratio as low as 0.6 when there are significant non-energy benefits which cannot be quantified.

As the name suggests, the UC only considers utility costs and utility benefits for the construction of the benefit-cost ratio. The basic costs and benefits included in the calculation of the test are listed below:

Costs:

1. Program Overhead Cost
    a. Marketing[1]
    b. Outside services[2]
    c. Internal labor & overhead[3]
    d. Miscellaneous expenses related to program activates[4]
2. Incentives provided to customers who purchase an energy efficient application
3. Other program specific costs[5]

Benefits:

1. Avoided cost of energy
    a. Market Cost of Energy
    b. Line losses
    c. Planning adjustments[6]
    d. Incremental cost avoidance of compliance with renewable portfolio standards
2. Avoided costs of capacity
    a. Deferred transmission and distribution (T&D) expense
    b. Total annual fixed cost of generating capacity

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[1] Marketing costs include all costs of advertizing, bill inserts, campaigns, radio advertisements, etc.
[2] Many of PSE programs are ran, in part, by outside vendors. Outside services costs include all costs to contractors and vendors, who are not PSE employees, which are incurred by the energy efficiency program.

[3] Internal labor and overhead include all PSE employee expenses and PSE incurred overhead costs

[4] Miscellaneous expenses include any incurred costs for event prizes, car rentals, PSE employee hotel rooms, etc. which are incurred as a result of operating the program.
[5] The costs listed above are standard for all program UC calculations for the exception of cost element three, 'other program specific costs'. Some programs have additional costs associated with them, such as the additional cost of natural gas on an electric to natural gas fuel conversion program. These costs need to be included in the costs for the UC calculation.
[6] Planning adjustment is the value of energy efficiency, in the IRP, which is not accounted for by market prices of energy, capacity, or avoided incremental investments in the Renewable Portfolio Standards.

2.3. Total Resource Cost Test

The TRC views demand side resource acquisition from a total cost and benefit perspective. The test determines the benefit of the demand side resource given the total cost, not simply the acquisition cost to the utility. PSE is required to run the TRC for both gas and electric programs.

As with the UC, a TRC benefit-cost ratio of one or greater is essential for programs to be considered for inclusion in a demand side resource portfolio. However, like the UC, there are also exceptions to this rule. State regulations allow PSE to run low-income weatherization programs which have a benefit cost-ratio as low as 0.6 when there are significant non-energy benefits which cannot be quantified.

The TRC considers all costs, including those incurred by the utility and by the customer. The costs and benefits included in the calculation of the TRC Test are listed below:

Costs:

1. Program Overhead Cost
   a. Marketing
   b. Outside Services
   c. Internal Labor & overhead
   d. Miscellaneous expenses related to program activates
2. Incentives provided to customers to purchase an energy efficient application
3. Tax rebates and other contributions for third parties
4. Customer cost of acquiring the efficient equipment or item, net of any incentives provided by the utility, tax incentives, or other contributions
5. Other Program specific costs

Benefits:

1. Avoided cost of energy
   a. Market Cost of Energy
   b. Line losses
   c. Planning adjustments when applicable
   d. Avoided cost of compliance with renewable portfolio standards
   e. Conservation credit[7]

[7] The conservation credit is a 10% adder for the electric benefits only. It does not apply to gas conservation programs. For more information about the conservation credit, read appendix A.

2. Avoided costs of capacity
    a. Deferred T&D expense
    b. Total annual fixed cost of generating capacity
    c. Conservation credit
3. Non-energy related benefits[8]

For the majority of programs, the benefit-cost ratio calculated through the TRC will be smaller than the ratio developed through the UC. This has to do with adding the additional customer costs, which typically are far greater than, thus outweighing, the addition of the conservation credit to the benefits in the TRC.

The benefit-cost ratio in the TRC may be higher than the ratio developed in the UC for programs with little to no customer cost. In these cases, the conservation credit, which is added to the benefits in the TRC, outweighs the small contribution of customer costs.

In theory, programs where non-energy benefits are significant and quantifiable, the benefit-cost ratio of the TRC can be far greater than the ratio developed though the UC. However, most non-energy related benefits are difficult to quantify in the majority of programs, and often times the non-energy benefit is not included in the calculation of the TRC.

PSE recognizes that many of our programs also save water. However, PSE does not currently invest the effort into trying to quantify non-energy benefits for programs that pass the TRC using only energy benefits. For the Low Income Weatherization Program, the value of health and safety measures was included as a non-energy benefit for the 2012-2013 gas cost-effectiveness calculations.

2.4. Ratepayer Impact Measure Test

The use of the RIM is new to PSE in 2012-2013 program planning. Unlike the UC and the TRC, the RIM does not have hard and fast decision making criteria for program selection. Instead, it is an attempt to understand how the demand side resource program impacts ratepayers. The RIM is required for PSE's electric portfolio evaluation only. It is not required for the gas energy efficiency cost-effectiveness analyses.

The costs and benefits included in the calculation of the RIM Test are listed below:

[8] Non-Energy Benefits include savings on non-energy related items. These include items like costs savings on water for low-flow showerheads.

Costs:

1. Program Overhead Cost
    a. Marketing
    b. Outside services
    c. Internal labor & overhead
    d. Miscellaneous expenses related to program activates
2. Incentives provided to customers to purchase an energy efficient application
3. Lost utility revenues due to demand side resource
4. Other program specific costs

Benefits:

1. Avoided cost of energy
    a. Market cost of energy costs at market
    b. Line losses
    c. Planning adjustments when applicable
    d. Avoided cost of compliance with renewable portfolio standards
    e. Conservation credit
2. Avoided costs of capacity
    a. Deferred T&D expense
    b. Total annual fixed costs of generating capacity

2.5. Participant Cost Test

The final test, the PCT is also new to PSE beginning with the 2012-2013 program planning. This test compares the customer costs of purchasing the efficient equipment to the customers' associated utility bill savings. Essentially, this test allows the utility to understand if the investment in the efficient equipment pays off for the customer.

The PCT considers all customer costs and bill savings, ignoring all utility incurred costs and utility benefit. This test is required for the electric portfolio evaluation only; it is currently not required for gas energy efficiency program cost-effectiveness evaluations. The costs and benefits included in the calculation of the PCT are listed below:

Costs:

1. Equipment costs

Benefits:

1. Bill savings
2. Program incentives
3. Applicable tax credits or incentives
4. Non-energy benefits which are incurred by the customer[9]

3. Key Drivers of the Cost-Effectiveness Calculations

3.1. Framework for Cost-Effectiveness Calculations

Cost-effectiveness calculations have several key drivers, which include: the avoided cost of energy, the avoided costs of capacity, program overhead costs, customer costs, program incentives, non-energy benefits, measure life, the load shape used in the calculation of avoided costs, and the discount rate used for calculating the present value of benefits and costs.

Each of the major drivers to the outcome of the cost-effectiveness calculations are discussed below.

3.2. Avoided Cost of Energy & Capacity

Avoided costs of energy and capacity are the main driver of the benefits that are included in PSE's cost-effectiveness calculations for energy efficiency programs. Higher avoided costs of energy and capacity make energy efficiency programs more attractive to PSE and more cost-effective for the utility, all other things being equal.

Because avoided costs are developed for individual end-use types, each end-use will be impacted differently by changes in energy costs[10]. In addition, changes in the avoided cost of capacity will impact the cost-effectiveness of energy of programs differently. Programs which save energy from heating-related efficiency upgrades will be impacted significantly by changes in the avoided cost of capacity because they have a higher coincident savings (savings on peak) than programs that save

[9] The participant cost test only considers non-energy benefits which are incurred by the customer, such as water savings. Non-Energy benefits that are not directly incurred by the customer cannot be included in the participant cost test.

[10] If, for example, winter prices of energy increase but summer prices remain the same, the avoided costs of space heat measures will increase more dramatically than the avoided energy costs of water heating measures, with no impact on residential air conditioning avoided energy costs.

energy in the summer[11]. Changes in the avoided cost of capacity will have relatively little impact on energy efficiency programs which provide low savings in the peak hours.

Avoided costs of capacity are a function of the cost of building capacity resources for peak load and the load shape of the measure being assessed in the avoided cost calculation. PSE's peak load typically occurs during the weekday mornings or evenings during the month of December. For equipment where loads coincide with peak hours, capacity costs are included in the avoided costs.

Space heating measures have a higher coincidence with peak than non-heating related measures, such as lighting. Therefore, the avoided costs of capacity have a much greater impact on space heat measures than they do on measures which are used at a fairly constant rate throughout the year. This is because a larger portion of the total load for space heating measures coincides with times where PSE is paying for peak resources.

3.3. Program Overhead Costs

Program overhead costs consist of all costs incurred to run an efficiency program, except those that are incentive-related. Program overhead costs consist of marketing costs, expenses incurred for outside services, internal labor and labor overhead costs, and miscellaneous expenses[12] related to other costs of program activity.

Program overhead costs have a direct impact on the cost-effectiveness of the related energy efficiency programs. All else equal, an increase in program overhead costs will decrease the cost-effectiveness of efficiency programs. Controlling program over head costs is one of the few ways for program managers to influence the outcome of a cost-effectiveness calculation.

3.4. Measure Costs

Like program overhead costs, measure costs have a direct impact the outcome of the cost-effectiveness calculations. To the extent that total measure costs influence the incentive provided by the utility, thus impacting the customer cost, the measure cost impacts all of the tests discussed in this document. All other things equal, an increase in the cost of a measure will decrease the benefit-cost ratio in the cost-effectiveness tests.

3.4.1. Incremental Cost or Full Measure Cost

For the calculation of benefit-cost ratios, PSE considers either the full measure cost or the incremental measure cost, depending on the item being offered though the energy efficiency programs and the delivery mechanism where the rebate occurs.

[11] PSE plans for a winter peak, not for a summer peak.
[12] Miscellaneous expenses refer to non-typical program expenses such as travel, gift cards for program participants, ect.

The majority of participants in PSE efficiency programs receive rebates when they are replacing old, worn equipment such as a furnace, water heater, or light bulbs. For these programs, PSE uses the incremental measure cost when calculating the benefit-cost ratios. The incremental measure cost is defined as the cost difference between the piece of equipment installed though the PSE program and the item the customer would have installed without program intervention. The cost associated with the item which would have been installed without program intervention is assumed to have occurred without the program. Therefore, it's not prudent to include the entire cost of the efficient equipment in the cost-effectiveness test.

For programs where customers receive rebates to add a new item to their home or make large changes to existing items which are fully functioning, PSE utilizes the full measure cost when calculating the benefit-cost ratios. Examples of measures for where the full measure costs are used include insulation, windows, and some early replacement programs[13].

3.4.2. Incentive

The incentive amount provided by the utility has no impact on the TRC because this test uses the full or incremental cost, both of which include the incentive and customer cost when calculating the benefit-cost ratio. A change in the incentive will change the cost to the customer, but the total or incremental cost will remain the same.

However, the incentive provided by the utility has a direct impact on the outcome of the Utility Cost Test, RIM Test and Participant Cost Test. When incentives are increased, all else equal, the benefit-cost ratio of the UC and the RIM will decrease, since this will increase the cost to the utility and/or ratepayers with no change in the level of benefits. On the other hand, incentives are included in the numerator (benefits) of the PC. When the utility increases incentives, energy efficient equipment becomes more cost-effective for customers, all else equal.

[13] In 2011, PSE is launching an early refrigerator replacement program. This program removes older, working refrigerators from customer homes and replaces them with new, efficient refrigerators. Because the customer was not going to purchase a refrigerator without the help of this program, incremental measure costs is non-existent. Therefore, full measure cost is considered for cost-effectiveness analyses of this program.

3.4.3. Customer Cost

Customer costs are those costs that the customer pays for the item being installed. For programs that have cost-effectiveness tests which use a full measure cost, the customer cost is the full measure cost minus the incentive provided to the customer. For programs that have cost-effectiveness tests which use the incremental measure cost, the customer cost is the incremental cost minus the incentive provided to the customer. There are a small number of programs which offer incentives greater than the incremental measure cost, and where the incremental (not the full) measure cost is used on the cost-effectiveness analyses. For these programs, customer costs are set to zero.

The customer cost associated with a measure offered though PSE efficiency programs does not have an impact on the UC or RIM because customer costs are excluded from these tests. In addition, the customer cost doesn't directly impact the TRC or PC because those tests use either the full measure cost or the incremental cost, both of which include the customer cost, when calculating the benefit-cost ratio.

Customer cost indirectly impact the TRC and the PC in that they are a component of the total or incremental cost of the item being offered though the efficiency programs. For a given level of incentives, an increase in customer cost is a reflection of an increase in total or incremental measure cost. The increase in total or incremental measure cost will decrease the benefit-cost ratios of the TRC and the PC.

3.5. Additional Costs & Benefits (O&M)

To be consistent with the Northwest Power and Planning Council (The Council), additional costs (as well as any cost savings) for operation and maintenance faced by customers installing energy efficient equipment though a PSE program are counted as an additional customer cost for the TRC and PC.

The cost of natural gas in a fuel switching program is an example of additional cost associated with participating in an energy efficiency program. To be consistent with the methodology used by the Council, PSE adds the cost of gas to the total utility cost when calculating the cost-effectiveness of fuel switching programs, which convert PSE electric customer to PSE gas. The reason this cost is not included as an additional customer cost is because it would not be reflected in the UC if the cost of gas was only applied to the customer. In fuel switching programs, PSE is required to purchase more natural gas and that needs to be reflected in the UC as well as the TRC. All else equal, additional operation and maintenance costs faced by the customer will decrease the benefit-cost ratios of the TRC and PCT. Added customer costs will have no impact on the UC or RIM Tests.

3.6. Non-Energy Benefits

Non-energy benefits are defined as all benefits from energy efficiency program which are not energy-related. Examples of these benefits are: water and other resource savings, improved health and safety, fewer shutoff notices for the utility and improved quality of life or product quality. Non-energy benefits are only included in the TRC, but PSE typically only quantifies these for the Low Income Weatherization Program when we have solid documentation. PSE does not typically include non-energy benefits in the TRC for standard programs because they are difficult to quantify and most programs pass the TRC without including the non-energy benefits.

Non-energy benefits can be positive or negative and are always included in the numerator of the test, regardless of the sign. Changes in non-energy benefits are positively correlated with the benefit-cost ratio of the TRC Test increases, all else equal.

3.7. Measure Life

The measure life is the rated useful life of the item(s) being provided though the program. Measure life is typically assessed using Regional Technical Forum[14] guidance or from PSE engineers and program managers who have a significant level of knowledge regarding the item being assessed.

Measure life and the associated benefit-cost ratios are positively correlated for all four of the cost-effectiveness tests conducted by PSE, all else equal.

3.8. End-Use Load Shape

The shape of the load for each measure being assessed in the cost-effectiveness calculations impacts the TRC, RIM, and Utility Cost Tests. Because PSE generally does not offer time-of-use rates, the shape of the load for each measure being assessed does not impact the Participant Cost Test.

PSE calculates avoided costs using multiple inputs. The avoided costs are higher for those items which have a significant portion of their load occurring in the winter. Because winter saving typically coincide with the system peak, which increases the avoided capacity cost, items which save energy in the winter are assigned a higher value for avoided capacity costs.

[14] The Regional Technical Forum (RTF) is an advisory committee which was developed in 1999 to develop standards for the evaluation of conservation savings.

3.9. Discount rate

For the 2012-2013 program years, the discount rate for PSE efficiency program avoided costs is set at 8.10%. This discount rate is the most recently approved rate of return on rate base ("ROR") by PSE's state regulators (in the 2009 General Rate Case) and was used in the development of the 2011 Integrated Resource Plan. As utility discount rates increase, the present value of avoided costs decreases. All else equal, an increase in the discount rate decreases the benefit-cost ratios of PSE's cost effectiveness tests. This discount rate is used for the avoided costs of energy and capacity in the UC, the TRC, and the RIM. The PC does not consider utility avoided costs.

3.1. Summary of Key Drivers

Key Driver	Direction of Key Driver	Direction of Benefit-Cost Ratios			
		TRC	UC	RIM	PCT
Avoided Energy and Capacity Costs	↓	↓	↓	↓	↓
	↑	↑	↑	↑	↑
Program Overhead Costs for the utility	↓	↑	↑	↑	N/A[15]
	↑	↓	↓	↓	N/A
Measure Cost	↓	↑	N/A[16]	N/A	↑
	↑	↓	N/A	N/A	↓
Incentive	↓	N/A	↑	↑	↓
	↑	N/A	↓	↓	↑
Non Energy Benefits	↓	↓	N/A	N/A	↓
	↑	↑	N/A	N/A	↑
Measure Life	↓	↓	↓	Ambiguous	↓
	↑	↑	↑	Ambiguous	↑
Discount Rate	↓	↑	↑	↑	↑
	↑	↑	↑	↑	↓

[15] The Participant Cost Test is not impacted by utility overhead costs because it only considers participant costs and the rebate provided by the utility
[16] The Utility cost and Ratepayer Impact Measure tests are not impacted

4. Constructing Benefit Cost Ratios

4.1. Using Benefit-Cost Ratios for Program Planning

Benefit-cost ratios provide useful information to PSE implementation teams. Programs with high benefit-cost ratios, and low free-ridership rates, are of primary interest for expansion should PSE need to acquire more demand side resources.

Before benefit cost-ratios can be used for program planning, the inputs into the ratios need to be accounted for correctly. This section provides clarification on what to include as non-energy benefits, how to correctly account for additional O&M costs (or cost savings) incurred by the customer, and how to select discount rates for O&M costs (or cost savings) incurred by the customer.

4.2. Accounting for Non-Energy Benefits

When including non-energy benefits in the benefit-cost ratios, always include the benefit in the numerator of the benefit-cost ratio. These benefits should not be included in the UC or RIM. All non-energy benefits which are quantifiable can be included in the TRC. Customer facing non-energy benefits can be counted in the PCT.

Non-energy benefits which cannot be estimated with supporting documentation should not be included in the TRC or the PCT cost effectiveness test.

Moreover, non-energy benefits which are included in the TRC and/or the PCT should be accompanied with supporting documentations and calculations.

4.3. Incorporating Additional Customer Costs

Additional customer incurred costs, which are not included in the cost of the measure being purchased thought the efficiency program, can be negative (cost savings) or positive. If the cost is negative (cost savings), the absolute value of the cost savings should be included in the numerator (non-energy benefit) of the benefit-cost ratio. The cost should be included in the denominator of the benefit-cost ratio whenever the cost is positive (representing an additional cost).

Examples of additional customer costs include the cost of natural gas when participating in an electric to gas fuel conversion program. The added cost of natural gas, for an electric to gas fuel switching program, is difficult to assess. On one hand, the cost of gas can be counted as an additional cost to the customer. On the other hand, the cost of gas can be counted as a cost incurred by the utility.

The UC ignores customer costs, which would exclude the additional cost of gas if counted as a customer cost. Therefore, the additional cost of gas is counted as a utility cost in the UC and placed in the denominator of the benefit-cost ratio. Similarly, because the TRC is a function of the UC, with added customer costs and non-energy benefits, the additional cost of gas for fuel conversion programs is also included as a utility cost and placed in the denominator of the benefit-cost ratio.

For the PCT, the cost of gas from an electric to gas fuel switching program is counted as a customer cost. Therefore, the additional cost of gas is included in the denominator of the Participant Cost Test.

4.4. Applying the Correct Discount rate

The rate used to discount costs or benefits for energy efficiency programs can impact the outcome of the benefit-cost ratios of PSE's cost-effectiveness tests.

When discounting additional costs, nominal discount rates should be used. For additional costs (or savings) faced by the utility, program teams should use PSE's the ROR approved in its most recent General Rate Case as the nominal discount rate.

4.5. Summary of Benefits and Costs to Include in Each Test

TEST	Benefits (NUMERATOR)	Costs (Denominator)
Perspective of Puget Sound Energy		
Utility Cost Test	1. Avoided Energy 2. Avoided Capacity Costs	1. Program Overhead Costs 2. Incentives a
Perspective of All PSE Customers		
Total Resource Cost Test	1. Avoided Energy 2. Avoided Capacity Costs 3. Non-Energy Benefits 4. Additional cost savings from Non-program related Items	1. Program Overhead Costs 2. Incentives 3. Customer Costs (incremental or full measure cost-incentive)
Impact of Efficiency on Non-Participating Rate Payers		
Ratepayer Impact Measurement Test	1. Avoided Energy Costs 2. Avoided Capacity Costs	1. Program Overhead Costs 2. Incentives 3. Customer Costs (incremental or full measure cost-incentive) 4. Lost Revenues due to reduced bills
Perspective of the Customer Installing the Measure		
Participant Cost Test	1. Incentive Payments 2. Bill Savings 3. Applicable Tax Credits 4. Non-Energy Benefits 5. Cost Savings from Non-program related Items (section 5.3)	1. Incremental or full cost of equipment being installed 2. Additional costs from non-program related items (section 5.3)