Draft Report

Comprehensive Assessment of Demand-Side Resource Potentials (2010-2029)

Prepared for:
Puget Sound Energy

[Note: use as information page; actual cover is in Adobe Illustrator]

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Executive Summary

Overview

This report summarizes the results of an independent study of the potentials for electric and natural gas demand-side management (DSM) resources in Puget Sound Energy's (PSE's) service area from 2010 to 2029. The study was commissioned by PSE as part of its biennial integrated resource planning (IRP) process.

The study builds upon previous efforts and incorporates improvements over the previous assessment in 2006 with respect to the scope of the assessment and its methodology. As in the previous study, the assessment included electric and natural gas energy efficiency, fuel conversion, demand response, and a full range of small-scale (customer-sited) generation resources. This study benefited from updated baseline and DSM data informed by primary and secondary data collection as well as the efforts of other entities in the region such as the Northwest Power and Conservation Council (the Council). The methods used to evaluate the technical potentials for and cost-effectiveness of resources draw upon the best practices in the utility industry and are consistent with the methodology used by the Council in its assessment of regional conservation potentials in the Northwest.

Summary of the Results

The potentials identified in this study are summarized in Table 1. As shown, electric DSM resources account for 760 aMW and 1,359 MW of achievable technical potential by 2029. These potentials represent 21% of retail energy sales and 28% of winter peak demand[1]. Similarly, technical achievable natural gas potential accounts for 19% of forecasted 2029 retail sales. High-level potentials by resource are presented below, with more detailed results in the following sections of this report.

[1] Demand response potentials do not account for program interactions, and thus, this potential would likely be reduced if multiple programs were competing for participants.

Table 1. Summary of Energy and Capacity Saving Potentials (2029)

	Energy (aMW / million therms)		Winter Peak Capacity (MW)	
Resource	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Electric Resources				
Energy Efficiency	739	589	1,162	926
Fuel Conversion	231	105	391	178
Demand Response	N/A	N/A	1,909	178
Distributed Generation	3,493	66	4,075	77
Electric Resources Total	4,463	760	7,537	1,359
Natural Gas Resources				
Energy Efficiency (million therms)	407	254	N/A	N/A

Energy Efficiency

Table 2 shows 2029 forecasted baseline electric sales and potential by sector. As shown, the results of this study indicate 739 aMW of technically feasible electric energy-efficiency potential will be available by 2029, the end of the 20-year planning horizon. Once market constraints are taken into account, this translates to an achievable potential of 589 aMW. Were all of this potential cost-effective and realizable, it would amount to a 16% reduction in 2029 forecasted retail sales and a 51% reduction of load growth from 2010 to 2029.

Table 2. Technical and Achievable Technical Electric Energy-Efficiency Potential (aMW in 2029) by Sector

Sector	Baseline Sales	Technical Potential	Technical Potential as % of Baseline	Achievable Technical Potential	Achievable Technical Potential as % of Baseline
Residential	1,756	343	20%	273	16%
Commercial	1,813	378	21%	301	17%
Industrial	135	17	13%	14	11%
Total	3,704	739	20%	589	16%

Table 3 shows 2029 forecasted baseline gas sales and potential by sector. As shown, the results of this study indicate roughly 407 million therms of technically feasible, gas energy-efficiency potential by 2029, the end of the 20-year planning horizon. This translates to an achievable technical potential of 254 million therms. If all of this potential was cost-effective and realizable, it would amount to a 19% reduction in 2029 forecasted retail sales and a 61% reduction in load growth from 2010 to 2029.

Table 3. Technical and Achievable Technical Gas Energy-Efficiency Potential (Million therms in 2029) by Sector

Sector	Baseline Sales	Technical Potential	Technical Potential as % of Baseline	Achievable Technical Potential	Achievable Technical Potential as % of Baseline
Residential	854	263	31%	162	19%
Commercial	440	132	30%	84	19%
Industrial	53	12	22%	9	17%
Total	1,348	407	30%	254	19%

Fuel Conversion

A summary of 2029 fuel conversion potentials is provided in Table 4. This represents a combination of current PSE gas customers and current PSE electric-only customers in either Cascade Natural Gas or PSE natural gas territory.

Table 4. Summary of Fuel Conversion Potentials

	Electric-Only Customers		Existing Gas Customers	Total
	PSE Gas Territory	Cascade Natural Gas Territory		
Technical Potential				
Electric Savings (aMW)	53.4	82.5	37.9	173.8
Additional Gas Usage (million therms)	32.9	53.5	20.7	107.1
Achievable Technical Potential				
Electric Savings (aMW)	20.3	29.8	15.2	64.9
Additional Gas Usage (million therms)	12.6	20.0	7.4	40.0

Demand Response

Table 5 and Table 6 present estimated resource potentials for all DR resources for the residential, commercial, and industrial sectors for summer and winter. As shown, demand response achievable technical potential represents a 3% and 1% reduction in 2029 winter and summer peak demand, respectively.

Table 5. Technical and Achievable Technical Potential for Demand Response Resources (MW in 2029) - Winter

Sector	2029 Sector Peak	2029 Technical Potential	2029 Achievable Technical Potential	Achievable Technical Potential As Percent of 2029 Sector Peak
Residential	3,577	1,729	170	5%
Commercial	2,901	135	14	<1%
Industrial	130	43	5	4%
Total	6,608	1,909	178	3%

Note: Individual results may not sum to total due to rounding.
Note: Interactions between programs have not been taken into account.
Note: Residential technical potential and achievable technical potential for residential potential for direct load control do not include AMR converted to AMI or existing AMI due to overlap with no AMR meter installed.

Table 6. Technical and Achievable Technical Potential for Demand Response Resources (MW in 2029) - Summer

Sector	2029 Sector Peak	2029 Technical Potential	2029 Achievable technical Potential	Achievable Technical Potential As Percent of 2029 Sector Peak
Residential	2,428	676	48	2%
Commercial	2,334	136	14	1%
Industrial	157	43	5	3%
Total	4,919	855	68	1%

Note: Individual results may not sum to total due to rounding.
Note: Interactions between programs has not been taken into account.
Note: Residential technical potential and achievable technical potential for direct load control do not include AMR converted to AMI or existing AMI due to overlap with no AMR meter installed.

Distributed Generation

The total technical potential from distributed generation resources, excluding existing installed capacity, is 3,493 aMW in 2029 (Table 7). More than half of the technical potential for DG comes from PV (51%), followed by non-renewable CHP (28%), small hydro (14%), renewable CHP (5%), and small wind (2%). The achievable technical potential is significantly lower than the technical potential due to economic considerations, low awareness of technologies, and other permitting or interconnection concerns. Among these resources, non-renewable CHP composes the largest percentage of achievable technical potential (34 aMW), followed by photovoltaics (21 aMW), renewable CHP (8.7 aMW), small hydro (0.12 aMW) and small wind (0.04 aMW).

Table 7. Technical and Achievable Technical Potential for Distributed Generation Resources (aMW in 2029)

Resource	Technical Potential	Achievable Technical Potential
Non-Renewable CHP	1,039	34
Renewable CHP	211	9
Building Photovoltaics	1,912	21
Small Hydro	265	<1
Small Wind	66	<1
Total	3,493	66

Energy Efficiency Potentials under Alternative Scenarios

To provide additional perspective on future availability of DSM resources and to take into account uncertainties around current economic conditions, an alternate scenario was analyzed. This scenario assumed that customer and load growth would be significantly lower than that included in the baseline forecast. In this scenario, by 2029, electric and gas sales have decreased by 3% and 6%, respectively. As Table 8 shows, this translated into similar reductions in potential. The industrial sector was affected the most, followed by the residential and commercial sectors.

Table 8. Energy Efficiency Technical Potential Comparison

Sector	Electric Technical Potential in 2029 (aMW)			Gas Technical Potential in 2029 (million therms)		
	Base Case	Low Growth	Percent Reduction	Base Case	Low Growth	Percent Reduction
Residential	343	332	3.2%	263	244	7.2%
Commercial	378	370	2.1%	132	126	4.5%
Industrial	17	16	5.9%	12	11	8.3%
Total	739	718	2.8%	407	381	6.4%

Although this analysis was not performed for all resources, it is expected that changes in potential, in percentage terms, would be similar.

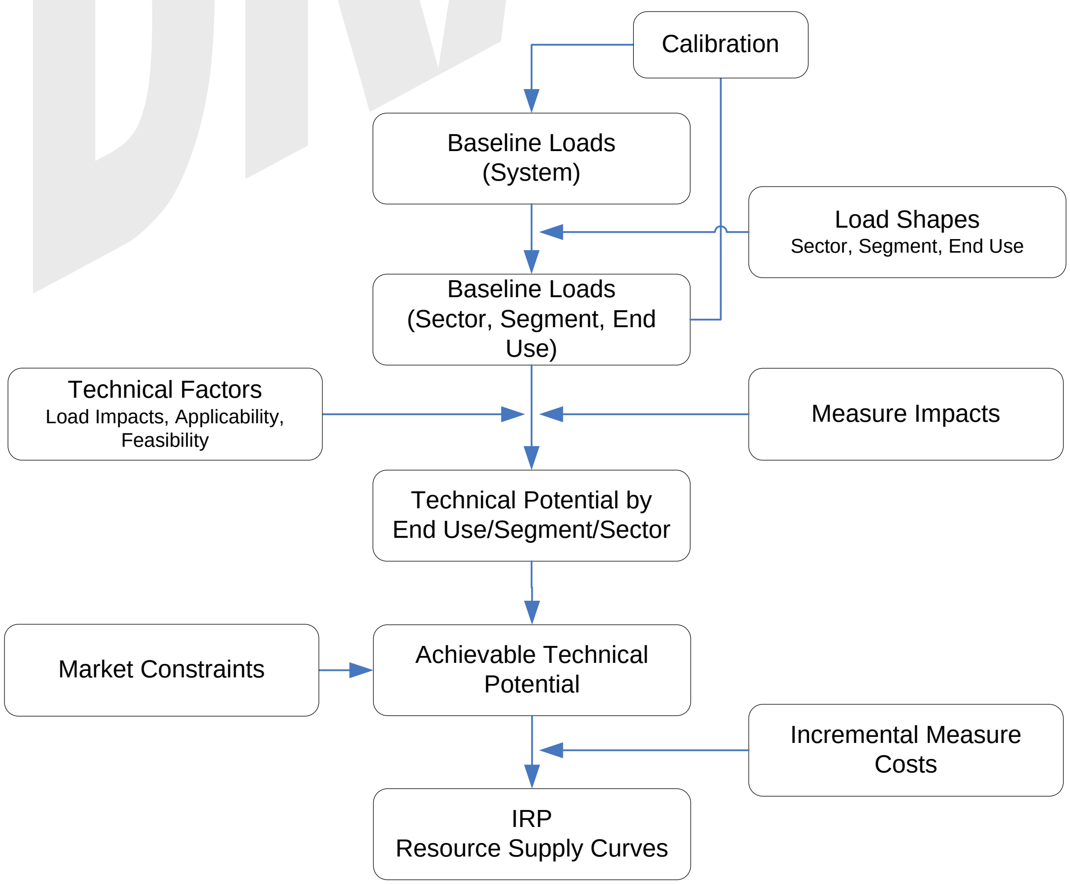
1. Introduction

General Approach and Methodology

The DSM resources analyzed in this study differ with respect to technology, availability, type of load impact, and target consumer markets. Analysis of their potentials, therefore, requires customized methods that can address the unique characteristics of each resource. These methods, however, spring from the same conceptual framework and the general analytic approach.

The general methodology is best described as a hybrid "top-down/bottom-up" approach. As illustrated in Figure 1, it begins with the current load forecast, decomposes it into its constituent customer-class and end-use components, and examines the effect of the range of demand-side measures and practices on each end use, taking into account fuel shares, current market saturations, technical feasibility, and costs. These unique impacts are then aggregated to produce estimates of resource potentials at the end-use, customer-class, and system levels.

Figure 1. General Methodology for Assessment of Demand-Side Resource Potentials



The standard methodology for determination of DSM potentials generally distinguishes four distinct, yet related, definitions of resource potential that are widely used in utility resource planning: naturally occurring conservation, “technical potential,” “economic potential,” and “achievable potential.”

Naturally occurring conservation refers to gains in energy efficiency that occur as a result of normal market forces such as technological change, energy prices, market transformation efforts, and improved energy codes and standards. In this analysis, the market effects components of naturally occurring conservation are taken into account by explicitly incorporating changes to codes and standards and marginal efficiency shares in the development of the base-case forecasts.

Technical potential assumes that all resource opportunities may be captured, regardless of their costs or market barriers. For demand-side resources such as energy efficiency and fuel conversion, technical potentials further fall into two classes: “instantaneous” (retrofit) and “phased-in” (lost-opportunity) resources. It is important to note that the notion of “technical potentials” is less relevant to resources such as demand response and distributed generation—nearly all end-use loads may be subject to interruption or displacement by on-site generation from a strictly “technical” point of view.

Economic potential represents a subset of technical potential consisting of only those measures that are deemed cost-effective based on a cost-effectiveness criterion, usually the total resource cost (TRC) test. For each measure, the test is structured as the ratio of the net present values of the measure’s benefits and costs. Only those measures with a benefit-to-cost ratio of equal or greater than 1.0 are deemed cost-effective and are retained for further analysis.

Achievable potential is defined as that portion of economic potential that might be assumed to be achievable in the course of the planning horizon, given market barriers that may impede customer participation in demand-side management programs sponsored by the utility. The assumed levels of achievable potentials are meant to serve principally as planning guidelines. Ultimately, the actual levels of achievable opportunities will depend on the customers’ willingness and ability to participate in the demand-side programs, administrative constraints, and availability of an effective delivery infrastructure. The customer’s willingness to participate in demand-side programs also depends on the amount of incentive that is offered.

For the purpose of the current IRP, the screening of energy efficiency resources will take place as part of the optimization process. Therefore, the measures included in the technical potential were not screened for cost-effectiveness. Instead, fixed ramp rates were directly applied to technical potential to create a supply curve for IRP modeling.

The methodology used for estimating the technical energy efficiency potential is based on standard industry practices and consistent wit the methodology used by the Northwest Power and Conservation Council (the Council) in its assessments of conservation potentials for the 6th Northwest Regional Power Plan. Electric energy efficiency technologies and measures considered in this include those approved by the Northwest Regional Technical Forum (RTF) and measures used in the 6th Power Plan. As described in Section 2, the ramp rates used to determine achievable potential for retrofit opportunities are comparable to – and in the case of phased-in, normal replacement higher than – those currently being proposed by the Council for calculating achievable potentials in the 6th Power Plan.

Comparison to 2008 IRP

While the results of this study are similar to those presented in the 2008 IRP, there are a number of reasons why we would expect some differences. These include:

- Updated baseline data from primary and secondary data collection efforts (See Appendix A)
- Updated consumption estimates from building simulation and conditional demand modeling
- Changes in codes and standards
- New measures included in the analysis (Table 9).
- New information on measure costs, savings, and applicability

Table 9. Number of measures considered in 2008 and 2010 IRP

Sector	Electric Measures Considered		Gas Measures Considered	
	2008 IRP	2010 IRP	2008 IRP	2010 IRP
Residential	65	118	30	51
Commercial	73	105	32	51
Industrial	9	16	4	8

Changes in any of these factors can lead to significant changes in identified potentials, especially when comparing at a granular level, such as by end use or measure.

Table 10 presents a comparison of the electric and natural gas technical potentials from this study and the 2008 IRP. Because no economic screen was performed as part of this study, it is difficult to compare quantities of economic or achievable potential. Some of the key differences are:

- Air conditioning – the new saturation survey showed an increased saturation of residential cooling equipment. This, combined with changes in available efficiency levels, led to a significantly higher technical potential.

- Electric cooking and drying – no measures were analyzed for these end uses in the previous study.

- Lighting – lighting decreased substantially both because of the effect of EISA described in the Executive Summary and because of the aggressiveness of PSE's lighting program over the past two years.

- Gas space and water heating – technical potential for these end uses increased dramatically, mainly due to differences in the measures analyzed. For space heating, new measures were included and some that were considered "emerging" in the last study, were deemed mature enough for inclusion in the energy efficiency potential (e.g. leakproof duct fittings). For water heating, the major difference was in the efficiency level of equipment considered. This study analyzed a 0.86 EF water heater, while the most efficient level considered in the previous study was 0.64 EF.

Table 10. Residential Energy Efficiency Technical Potential Comparison

	20-Year Electric Technical Potential (aMW)		20-Year Gas Technical Potential (million therms)	
End Use	2008 IRP	2010 IRP	2008 IRP	2010 IRP
Central AC	2.1	8.8		
Cooking	-	5.5	1.5	0.4
Dryer	-	4.1	-	0.3
Freezer	2.1	13.1		
HVAC Auxiliary	-	23.8		
Heat Pump	11.6	14.5		
Lighting	137.9	74.5		
Plug Loads	30.0	39.4		
Pool Heating	-	-	0.7	0.2
Refrigerator	12.0	25.5		
Room AC	0.2	1.0		
Space Heating	65.8	71.4	92.3	162.2
Water Heating	48.5	48.5	32.8	100.4
Total	310	330	127	263

In the commercial sector, estimates of total technical potentials are very close (Table 11). The major difference was the reclassification of some of the heating and cooling potential into the HVAC Auxiliary (ventilation) end use. Refrigeration potential also increased due to inclusion of additional measures and updated consumption and saturation numbers.

Table 11. Commercial Energy Efficiency Technical Potential Comparison

	20-Year Technical Potential (aMW)		20-Year Gas Technical Potential (million therms)	
End Use	2008 IRP	2010 IRP	2008 IRP	2010 IRP
Cooking	-	1.6	1.52	4.0
Cooling Chillers	32.6	14.0		
Cooling DX	58.1	19.5		
HVAC Auxiliary	1.4	44.8		
Heat Pump	18.6	27.8		
Heating	61.4	27.3	92.3	94.7
Lighting	176.6	138.2		
Plug Loads	4.9	51.3		
Pool Heating	-	-	0.7	0.5
Refrigeration	10.9	42.4		
Water Heating	9.3	11.1	32.8	32.5
Total	374	378	127	132

The industrial sector saw only minor changes on the electric side (Table 14). For gas customers, additional potential in process heating was identified.

Table 12. Industrial Energy Efficiency Technical Potential Comparison

	20-Year Technical Potential (aMW)		20-Year Gas Technical Potential (million therms)	
End Use	2008 IRP	2010 IRP	2008 IRP	2010 IRP
Boiler			3.5	2.2
HVAC	2.0	2.4	0.9	1.4
Lighting	1.6	0.7		
Process Cooling	1.4	0.9		
Process Heating	-	2.3	-	8.0
Process Motors Air Compression	3.2	3.8		
Process Motors Fans	1.3	0.8		
Process Motors Other	2.4	3.4		
Process Motors Pumps	5.9	1.5		
Process Motors Refrigeration	0.8	1.0		
Process Other			-	0.2
Total	19	17	4	12

Effects of the Energy Independence and Security Act of 2007

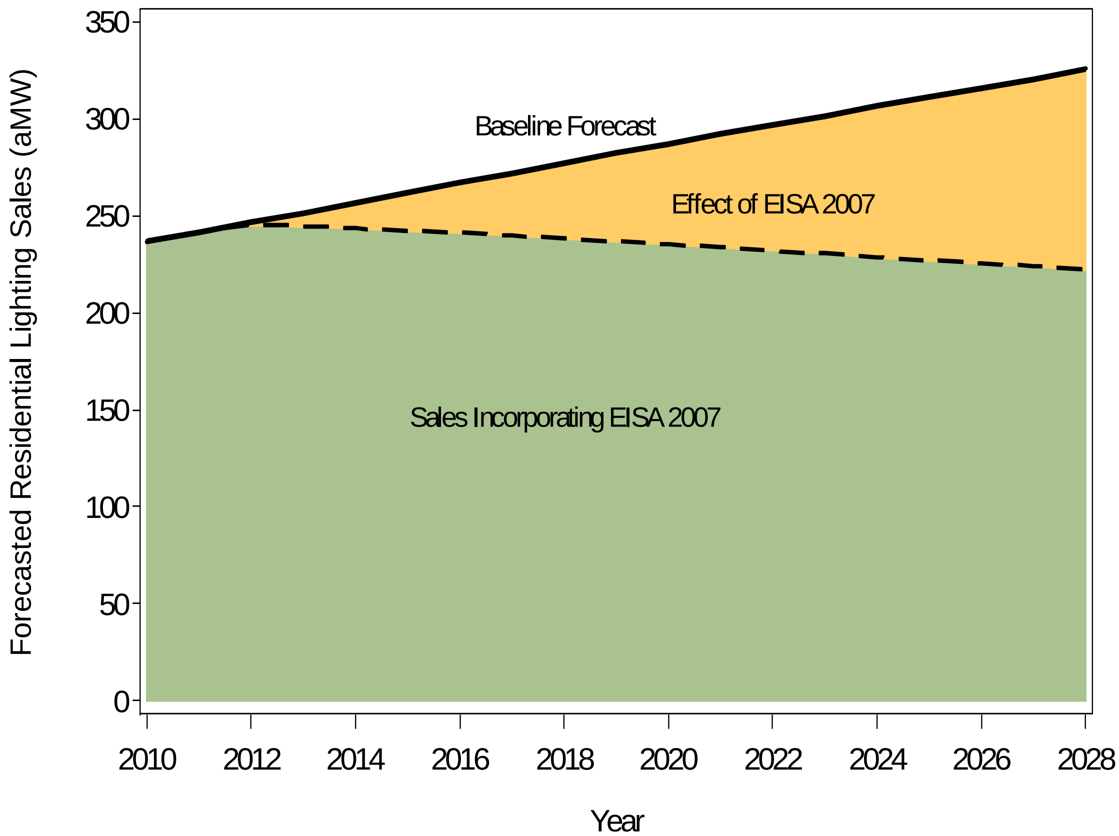
While this analysis does not attempt to predict how energy codes and standards may change in the future, it does capture legislation that has already been enacted, even if it will not go into effect for several years. The most notable of these is the Energy Independence and Security Act (EISA) of 2007, which sets new standards for general service lighting, motors, and other end-use equipment. Because of the large role residential lighting plays in PSE's energy-efficiency programs, it was particularly important to capture the effects of this legislation. EISA requires general service lighting becomes roughly 30% more efficient, with standards phased in by wattage beginning in 2012.

PSE and Cadmus coordinated with the Council to ensure consistency in assumptions about how lighting standards would affect loads and potential going forward. These discussions led to the following conclusions:

- As no technology currently available meets the EISA standards and costs less than a Compact Fluorescent Light (CFL) bulb, it is assumed CFLs will become the de facto baseline.
- When the legislation takes effect, standard incandescent light bulbs will still be in use and in reserve; so switchover will not occur all at once. Thus, it is assumed sockets will convert to CFLs (roughly) equally from 2012 to 2029.
- Because EISA requirements only apply to general service lighting, there will still be some CFL potential for non-standard applications.
- LED technology may become viable for general service applications, creating another source of savings.

Figure 2 shows the effect EISA is expected to have on PSE's residential lighting sales over the planning horizon. It is anticipated these new lighting standards will reduce sales in 2029 by nearly 110 aMW, or 33% of baseline lighting consumption.

Figure 2. Baseline and EISA 2007 Residential Lighting Forecasts



Organization of the Report

This report is organized in four sections with one section presenting the results of each resource type: energy efficiency, fuel conversion, demand response, and distributed generation. Additional technical information, descriptions of data and their sources are presented in the appendices to this document.

2. Energy-Efficiency Potentials

Scope of Analysis

The primary objective in this assessment was to develop accurate estimates of available energy-efficiency potential, essential for PSE's IRP and program planning efforts. To support these efforts, Cadmus performed an in-depth assessment of technical and "achievable technical" potential for electric and gas resources in the residential, commercial, and industrial sectors. This potential was then bundled in terms of cost of conserved energy, allowing the IRP model to determine the optimal amount of energy-efficiency potential to select. This represents a change in methodology from previous IRPs, where the achievable potential was prescreened for cost-effectiveness and put into the IRP model as a must-take resource.

To bundle potential by cost, data on measure costs, savings, and market size were collected at the most granular level possible. Within each fuel and sector, the study distinguished between customer segments or facility types and their respective applicable end uses. Six residential segments (existing and new construction for single-family, multifamily, and manufactured homes), 20 commercial segments (10 building types within the existing and new construction vintages), and 34 industrial segments (17 facility types, also within existing and new construction vintages) were analyzed.

The study includes a comprehensive set of energy-efficiency electric and natural gas measures applicable to the climate and customer characteristics of PSE's service territory. This list includes both measures analyzed for the previous IRP and new measures that have become commercially available since the last study. The analysis began by assessing the technical potential for 239 *unique* electric and 110 unique gas energy-efficiency measures (Table 13). Considering all permutations of these measures across all customer sectors, segments, and fuels, customized data had to be compiled and analyzed for over 6,700 measures.

Table 13. Energy-Efficiency Measure Counts by Fuel

Sector	Electric Measure Counts	Gas Measure Counts
Residential	118 unique, 1,198 permutations across segments	51 unique, 435 permutations across segments
Commercial	105 unique, 2,866 permutations across segments	51 unique, 1,430 permutations across segments
Industrial	16 unique process improvements, 664 permutations across segments	8 unique process improvements, 125 permutations across segments

The remainder of this section is divided into three parts: a brief description of the methodology for estimating technical and economic potential; a summary of resource potentials by fuel; and, finally, detailed sector-level results.

Methodology

The basic methodology for estimating energy-efficiency potential is consistent for all six sector-fuel combinations:

- **Develop baseline forecast:** A baseline forecast is created based on end-use consumption estimates, calibrated to PSE's base year sales and official forecast. This provides accurate estimates of consumption by fuel, sector, customer segment, end use, and year.

- **Compile measure lists:** All measures applicable to PSE's climate and customers were analyzed to accurately depict the energy-efficiency potential over the 20-year planning horizon. When expanded by fuel, customer segment, end use, and vintage, this list totaled over 6,700 measures (as discussed above).

- **Estimate technical potential:** An alternate forecast was created where all technically feasible measures were assumed to be installed. The difference between this forecast and the baseline represents the technical potential in each year. The effects of EISA 2007 were removed from this potential, as described in the Executive Summary.

- **Estimate "achievable technical" potential:** A subset of the technical potential was taken to reflect the maximum that could be achieved after accounting for market barriers, assuming PSE was willing to pay up to 100% of incremental cost in incentives. The percent of technical potential deemed "achievable" is consistent with the previous IRP and the Northwest Power & Conservation Council (Table 14)

Table 14. 20 Year Market Penetration Rates by Fuel and Sector

	Electric		Gas	
Sector	Existing Construction	New Construction	Existing Construction	New Construction
Residential	85%	65%	75%	55%
Commercial	85%	65%	75%	55%
Industrial	85%	65%	75%	55%

- **Create IRP bundles by cost:** The achievable technical potential was finally grouped into bundles by the cost of conserved energy for inclusion in the IRP model. Price points were defined based on estimates of PSE's avoided energy costs under several different scenarios.

A detailed discussion of the methodology for estimating energy-efficiency potential is presented in Volume II, Appendix C.

Summary of Resource Potential—Electric

Table 15 shows 2029 forecasted baseline electric sales and potential by sector. As shown, the results of this study indicate 739 aMW of technically feasible electric energy-efficiency potential will be available by 2029, the end of the 20-year planning horizon. This translates to an achievable technical potential of 589 aMW. Were all of this potential cost-effective and realizable, it would amount to a 16% reduction in 2029 forecasted retail sales and a 51% reduction of load growth from 2010 to 2029.

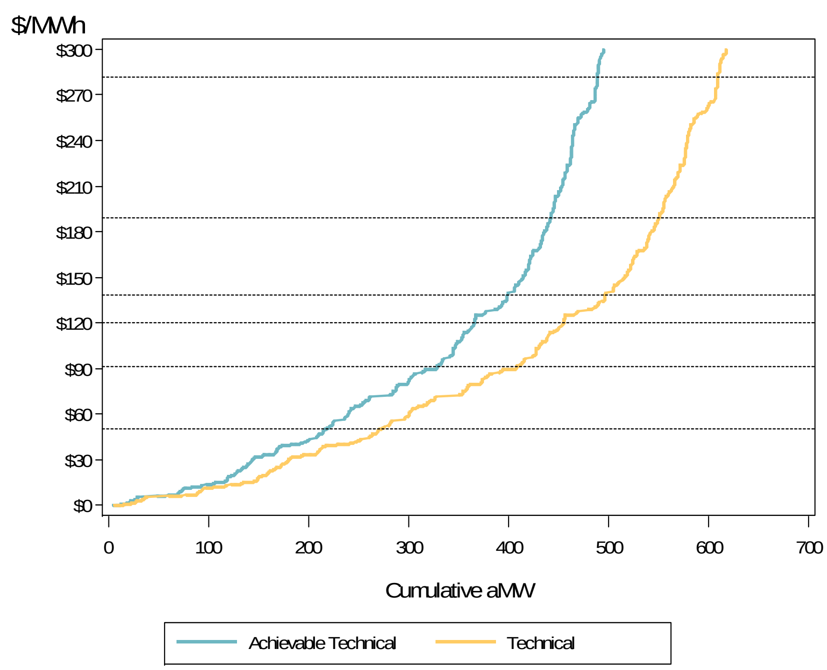
Table 15. Technical and Achievable Technical Electric Energy-Efficiency Potential (aMW in 2029) by Sector

Sector	Baseline Sales	Technical Potential	Technical Potential as % of Baseline	Achievable Technical Potential	Achievable Technical Potential as % of Baseline
Residential	1,756	343	20%	273	16%
Commercial	1,813	378	21%	301	17%
Industrial	135	17	13%	14	11%
Total	3,704	739	20%	589	16%

These savings are based on forecasts of future consumption absent any utility program activities. While consumption forecasts account for the past savings PSE has acquired, the estimated potential is inclusive of—not in addition to—current or forecasted program savings.

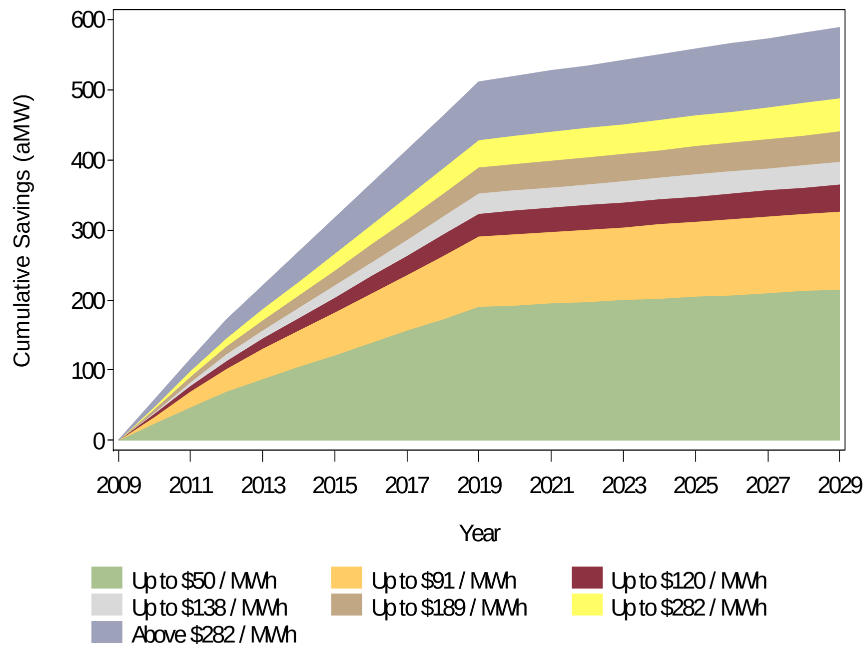
Figure 3 illustrates how identified potential translates into IRP bundles by cost of conserved energy. The horizontal dashed lines represent the cost cutoffs that identify the bundles. For example, roughly 200 aMW of achievable potential was offered to the IRP model at a cost below $50 per MWh. Measures with a levelized cost above $282 per MWh were not included in IRP modeling.

Figure 3. Electric Potential by IRP Cost Bundle – Cumulative 2029



The cumulative potential available is presented in Figure 4 by year and cost group. It is assumed retrofit opportunities in existing buildings can be captured within 10 years, whereas new construction and equipment replacement potential can only be captured as it becomes available over the 20-year planning horizon.

Figure 4. Acquisition Schedule for Achievable Technical Electric Savings by Cost Group



Summary of Resource Potential – Gas

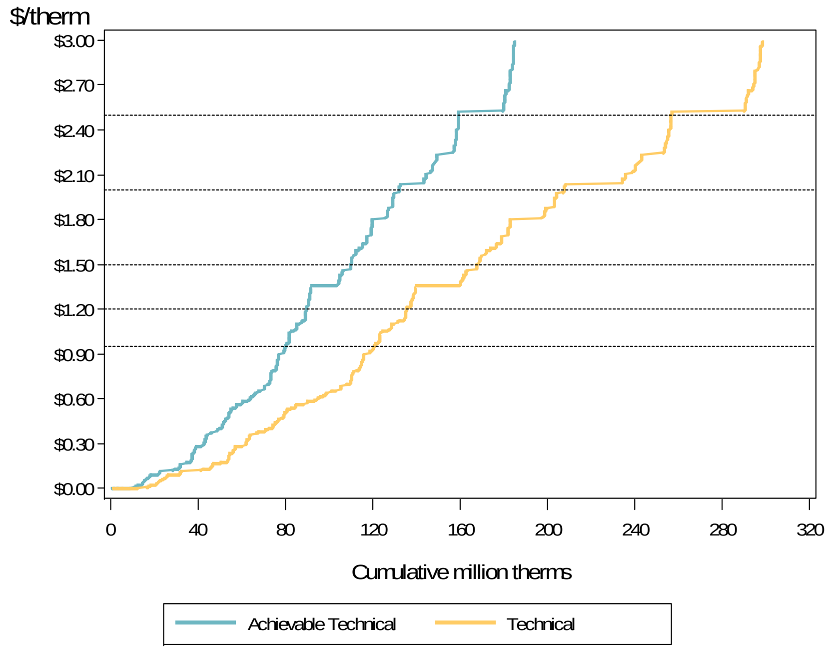
Table 16 shows 2029 forecasted baseline gas sales and potential by sector. As shown, the results of this study indicate roughly 407 million therms of technically feasible, gas energy-efficiency potential by 2029, the end of the 20-year planning horizon. This translates to an achievable technical potential of 254 million therms. If all of this potential was cost-effective and realizable, it would amount to a 19% reduction in 2029 forecasted retail sales and a 61% reduction in load growth from 2010 to 2029.

Table 16. Technical and Achievable Technical Gas Energy-Efficiency Potential (Million therms in 2029) by Sector

Sector	Baseline Sales	Technical Potential	Technical Potential as % of Baseline	Achievable Technical Potential	Achievable Technical Potential as % of Baseline
Residential	854	263	31%	162	19%
Commercial	440	132	30%	84	19%
Industrial	53	12	22%	9	17%
Total	1,348	407	30%	254	19%

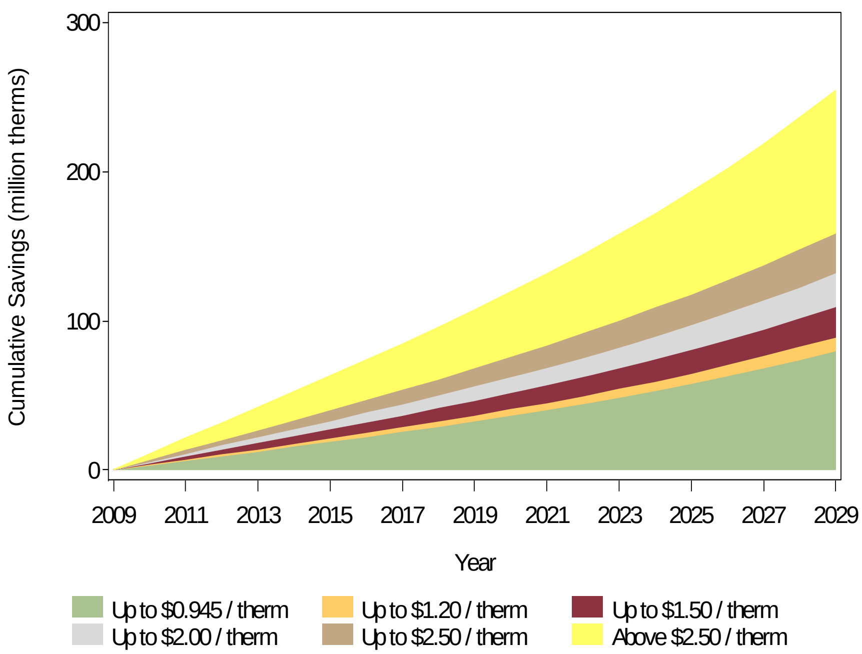
Figure 5 illustrates how identified potential translates into IRP bundles by cost of conserved energy for gas measures. The horizontal dashed lines represent the cost cutoffs that identify the bundles. For example, roughly 75 million therms of achievable potential were offered to the IRP model at a cost below $0.95 per therm. Measures with a levelized cost above $2.50 per therm were not included in IRP modeling.

Figure 5. Natural Gas Potential by IRP Cost Bundle—Cumulative 2029



The cumulative potential available is presented in Figure 6 by year and cost group. As PSE's natural gas energy-efficiency programs are still relatively new, the assumptions regarding timing of resource acquisition are less aggressive than for electric resources. It is assumed it will take the full 20 years to capture retrofit opportunities in existing construction and that program activity will ramp up over time.

Figure 6. Acquisition Schedule for Achievable Technical Natural Gas Savings by Cost Group



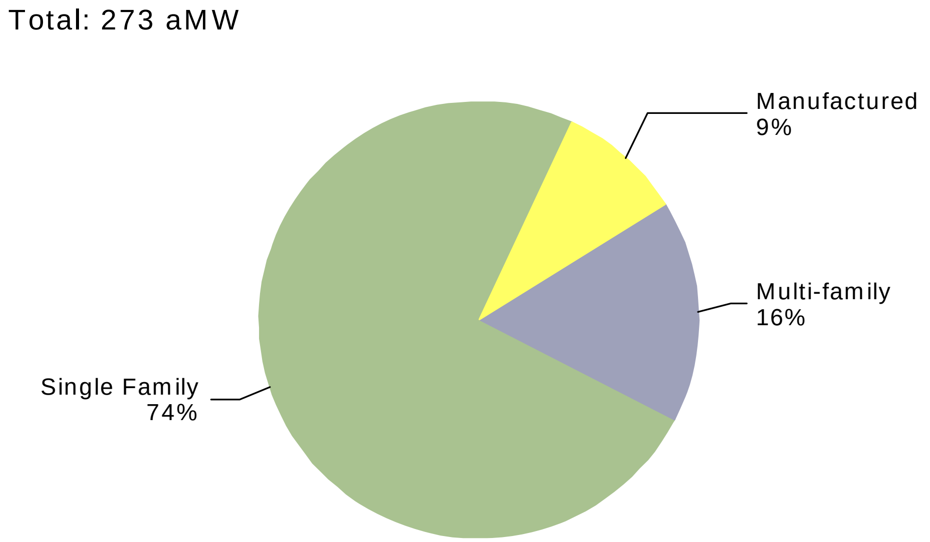
Detailed Resource Potential

Residential Sector—Electric

Residential customers in PSE's service territory are expected to account for almost one-half of baseline electricity retail sales by 2029. The single-family, manufactured, and multifamily dwellings that comprise this sector present a variety of potential savings sources, including equipment efficiency upgrades (e.g., air conditioning, refrigerators), improvements to building shells (e.g., insulation, windows, air sealing), and increases in lighting efficiency (e.g., compact fluorescent light bulbs, LED interior lighting). As described in the Executive Summary, the expected impacts of new lighting standards created in EISA 2007 have been removed from the potential presented in this section.

As shown in Figure 7, single-family homes represent 74% of the total achievable technical residential electric potential, followed by multifamily and manufactured homes (16% and 9%, respectively). The main driver of these results is each home type's proportion of baseline sales, but other factors, such as heating fuel sources, play an important role in determining potential. For example, manufactured homes typically have more electric heating than other home types, which increases their relative share of the potential. On the other hand, the lower use per customer for manufactured units serves to decrease this potential, as the same measure may save less in a manufactured home than in a single-family home. A comprehensive list of the specific factors affecting the results are included in the segment-specific data, provided in Volume II, Appendix C.

Figure 7. Residential Sector Electric Achievable Technical Potential by Segment



Despite the effects of EISA 2007, lighting represents the largest portion (26%) of achievable technical potential, followed closely by heating savings (21%). Appliances (refrigerators, freezers, dryers, etc.), water heating, and plug loads each represent over 10% of the total identified potential. Figure 8 shows the total achievable technical potential by end-use group. Detailed potentials by end use and cost group are presented in Table 17.

Figure 8. Residential Sector Electric Achievable Technical Potential by End Use

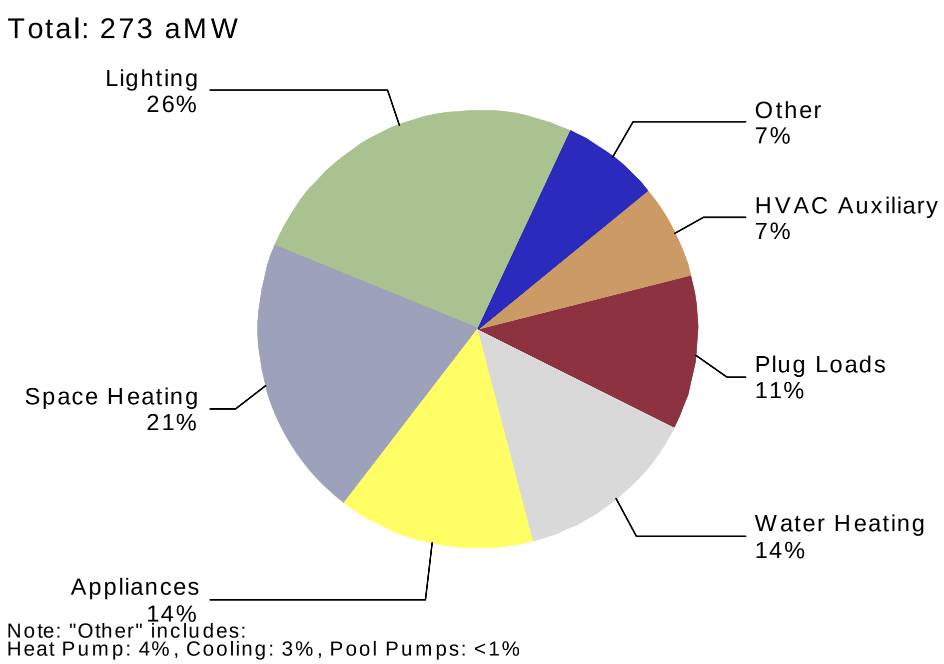


Table 17. Residential Sector Electric Energy-Efficiency Potential by End Use (aMW in 2029)

			Achievable Technical Potential						
End Use	Baseline Sales	Technical Potential	Under $50/MWh	Under $91/MWh	Under $120/MWh	Under $138/MWh	Under $189/MWh	Under $282/MWh	All Costs
Central AC	17.2	8.8	0.3	0.4	0.5	0.6	0.6	1.6	6.9
Cooking	127.6	5.5	-	-	-	-	-	-	4.3
Dryer	87.0	4.1	-	3.2	3.2	3.2	3.2	3.2	3.2
Freezer	44.4	13.1	8.5	10.7	10.7	10.7	10.7	10.7	11.0
HVAC Auxiliary	79.1	23.8	-	-	0.9	9.0	12.2	12.3	19.1
Heat Pump	40.1	14.5	2.1	5.6	6.1	6.2	6.4	7.1	11.6
Lighting	330.0	74.5	37.5	51.8	54.8	64.0	64.3	68.8	70.3
Plug Loads	458.4	39.4	0.0	8.3	8.6	9.0	17.3	23.6	31.1
Refrigerator	89.3	25.5	13.6	14.4	14.4	14.4	16.6	16.6	20.9
Room AC	4.6	1.0	0.0	0.0	0.0	0.0	0.1	0.2	0.8
Space Heating	284.9	71.4	10.4	22.8	25.6	26.7	32.4	34.9	57.1
Water Heat	192.8	48.5	23.6	23.9	25.5	28.4	32.2	34.4	37.1
Total	1,756	330	96	141	150	172	196	213	273

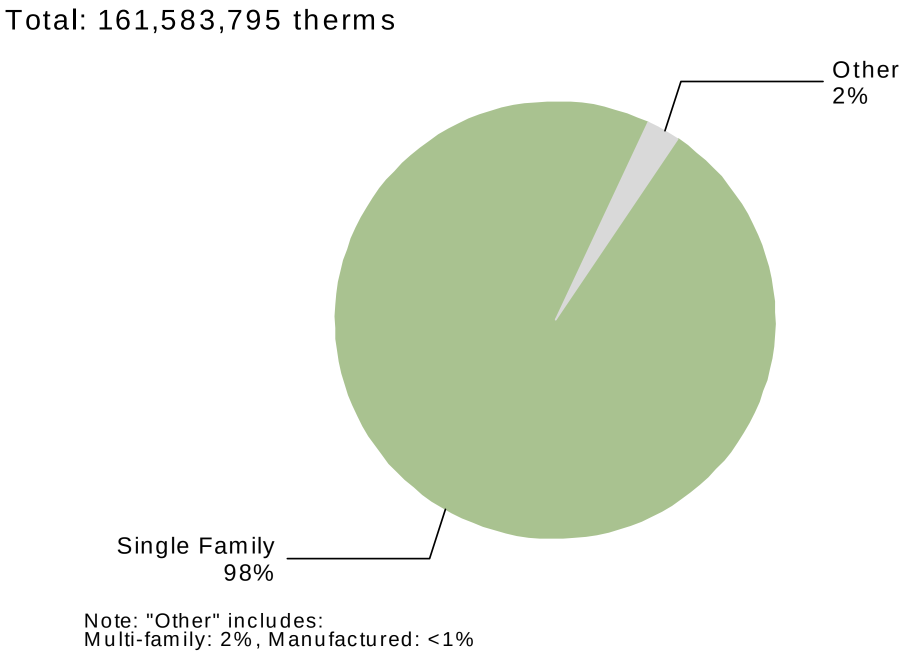
Additional details regarding the savings associated with specific measures assessed within each end use are provided in Volume II, Appendix C.

Residential Sector—Natural Gas

By 2029, residential customers are expected to account for over 60% of PSE's gas sales. Unlike residential electricity consumption, relatively few gas-fired end uses exist (primarily, space heat, water heat, and appliances); however, significant energy savings opportunities still exist. Based on resources included in this assessment, gas achievable technical potential in the residential sector is expected to be about 162 million therms over 20 years, corresponding to a 19% reduction of forecasted 2029 sales.

Single-family homes account for 71% of PSE's residential customers and 73% of baseline sales. Because of this, these homes account for 98% of the identified achievable technical potential, as shown in Figure 9. There is a small amount (2%) of potential in multifamily residences, but very little in manufactured homes due to lack of gas connections.

Figure 9. Residential Sector Gas Achievable Technical Potential by Segment



Space and water heating account for over 99% of the identified potential (Figure 10). This potential is a combination of high-efficient equipment (e.g., furnaces and water heaters) and retrofits, such as shell measures, duct and pipe insulation, and low-flow showerheads. Table 18 presents 2029 baseline sales, as well as technical and achievable technical potential by cost group for each end-use analyzed. The "other" category refers to end uses not easily characterized, such as gas fireplaces, hot tubs, and saunas.

Figure 10. Residential Sector Gas Achievable Technical Potential by End Use

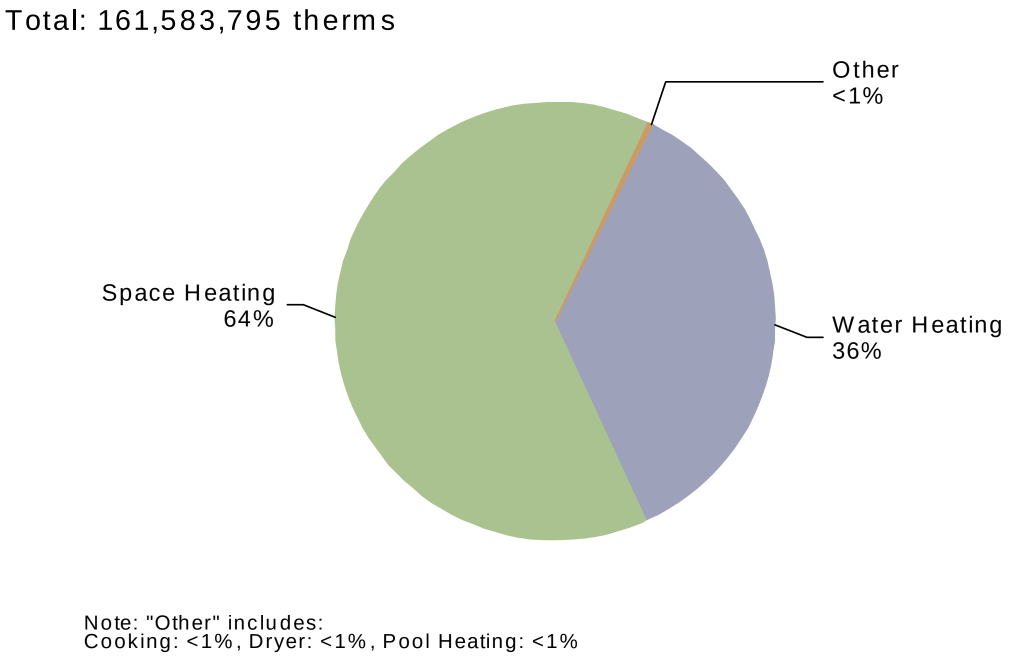


Table 18. Residential Sector Gas Energy-Efficiency Potential by End Use (Million therms in 2029)

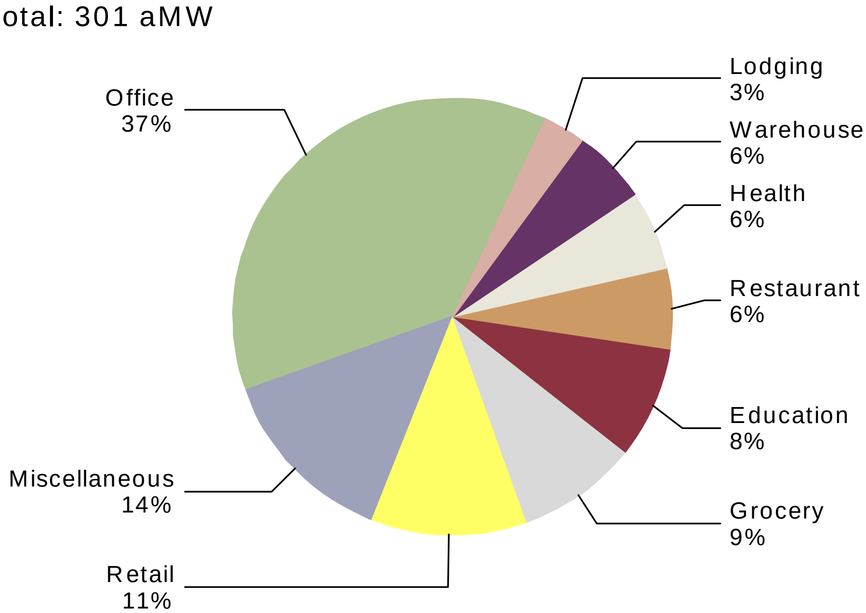
End Use	Baseline Sales	Technical Potential	Achievable Technical Potential Under $0.95/therm	Under $1.20/therm	Under $1.50/therm	Under $2.00/therm	Under $2.50/therm	All Costs
Cooking	16.5	0.4	-	-	-	-	-	0.3
Dryer	5.9	0.3	-	-	0.1	0.1	0.1	0.1
Other	29.6	-	-	-	-	-	-	-
Pool Heating	5.5	0.2	-	-	-	-	-	0.1
Space Heating	555.9	162.2	35.1	37.3	53.6	59.9	69.7	103.2
Water Heating	240.8	100.4	13.0	13.0	13.0	23.0	33.6	57.9
Total	854	263	48	50	67	83	103	162

Commercial Sector—Electricity

Based on resources included in this assessment, electric achievable technical potential in the commercial sector is expected to be just over 300 aMW over 20 years, corresponding to a 17% reduction of forecasted 2029 commercial consumption. Though similar in percentage terms, this potential is slightly higher than that of the residential sector, due to larger baseline sales.

As shown in Figure 11, offices and miscellaneous buildings combined represent just over half of the available potential (51%), 37% and 14%, respectively. The miscellaneous segment is a combination of customers that do not fit into one of the other categories or do not have enough information to be classified. Considerable savings opportunities are also expected in the commercial sector's retail (11%), grocery (9%), and education (8%) segments. Moderate savings amounts are expected to be available in health, restaurants, and lodging facilities.

Figure 11. Commercial Sector Electric Achievable Technical Potential by Segment



As in the residential sector, lighting efficiency represents by far the largest portion of achievable technical potential in the commercial sector (37%), followed by plug loads (13%), HVAC auxiliary (12%), and refrigeration (11%), as shown in Figure 12. The large lighting potential includes bringing existing buildings to code and exceeding code in new and existing structures. Table 19 shows how baseline sales and savings are distributed across end uses.

Figure 12. Commercial Sector Electric Achievable Technical Potential by End Use

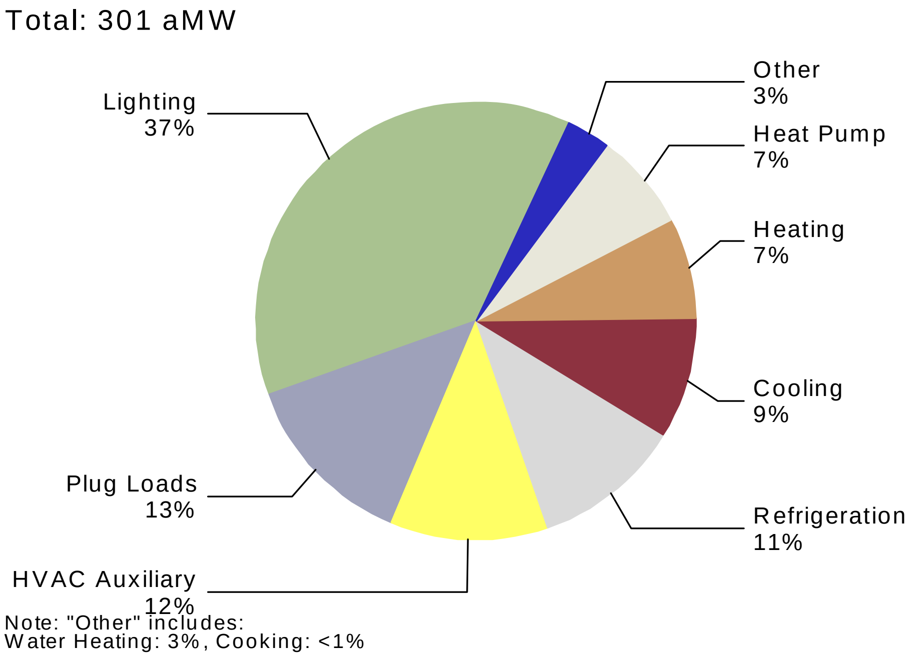


Table 19. Commercial Sector Electric Energy-Efficiency Potential by End Use (aMW in 2029)

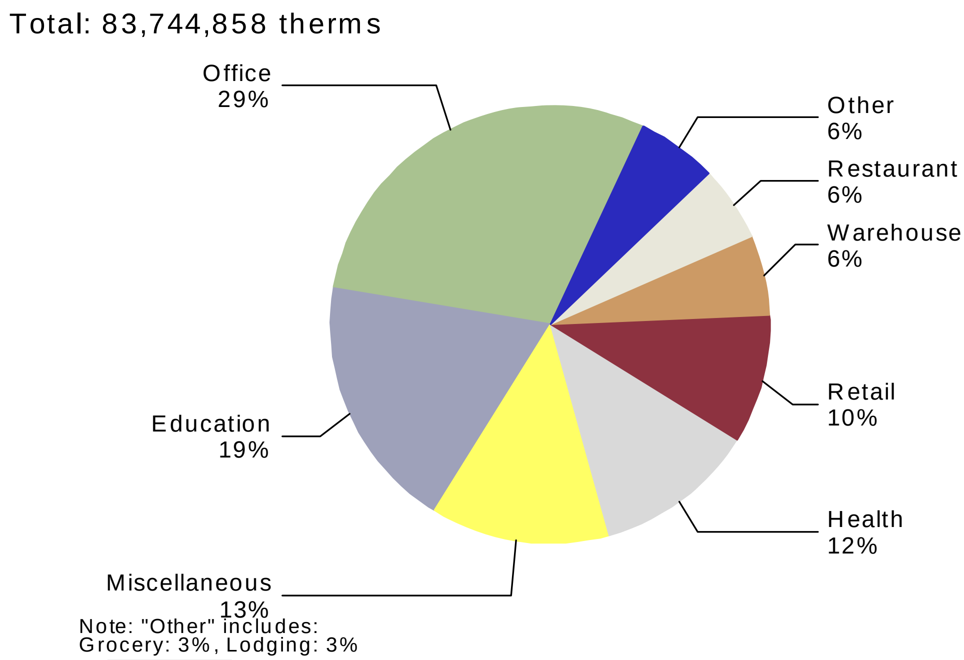
End Use	Baseline Sales	Technical Potential	Achievable Technical Potential						
			Under $50/MWh	Under $91/MWh	Under $120/MWh	Under $138/MWh	Under $189/MWh	Under $282/MWh	All Costs
Cooking	24.2	1.6	0.1	0.3	0.3	0.4	0.6	0.7	1.3
Cooling Chillers	22.2	14.0	0.3	0.8	2.1	2.7	3.2	6.7	11.2
Cooling DX	51.3	19.5	0.0	0.2	0.3	0.3	0.7	2.4	15.6
Dryer	43.3	-	-	-	-	-	-	-	-
HVAC Aux	229.1	44.8	24.1	29.4	31.3	32.3	32.8	33.2	35.0
Heat Pump	71.8	27.8	0.1	2.0	6.8	7.8	10.3	15.3	21.8
Heating	82.0	27.3	1.3	2.2	3.1	3.3	4.4	13.0	22.3
Lighting	554.8	138.2	21.9	73.1	91.2	96.9	109.6	111.7	112.6
Miscellaneous End Uses	36.1	-	-	-	-	-	-	-	-
Plug Loads	534.7	51.3	28.6	31.6	31.7	33.4	33.4	39.5	39.8
Refrigeration	102.0	42.4	26.7	28.7	30.0	30.0	30.8	32.4	33.0
Water Heating	61.4	11.1	2.3	3.5	4.0	4.2	4.8	5.3	8.4
Total	1,813	378	106	172	201	211	231	260	301

Commercial Sector—Natural Gas

Achievable technical natural gas potential in the commercial sector represents about a third of the total identified potential. The 84 million therms identified represent a 19% reduction in forecasted 2029 sales.

As for electric potential in the commercial sector, office buildings are the segment with the largest identified potential (29%, Figure 13). Significant amounts of achievable technical potential are also available in education (19%), miscellaneous buildings (13%), health facilities (12%), and retail (10%). Moderate savings amounts are expected to be available in warehouses, restaurants, grocery stores, and lodging facilities.

Figure 13. Commercial Sector Gas Achievable Technical Potential by Segment



As in the residential sector, there are far fewer gas-fired end uses than electric. Space heating accounts for over 70% of the identified potential. The remaining potential is almost entirely in water heating (25%), with small amounts in cooking and pool heating (Figure 14 and Table 20).

Figure 14. Commercial Sector Gas Achievable Technical Potential by End Use

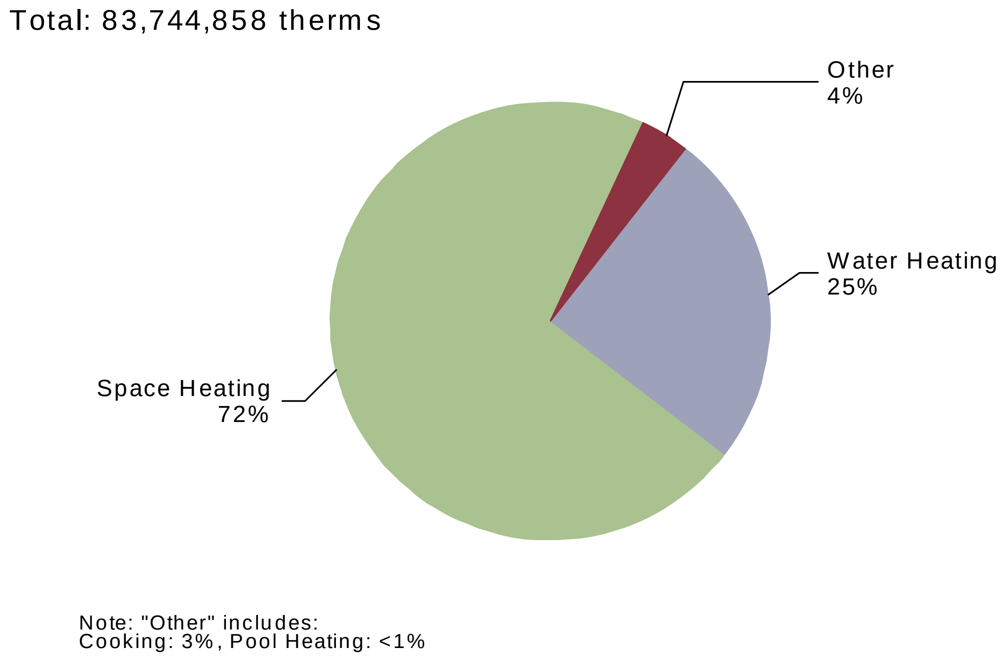


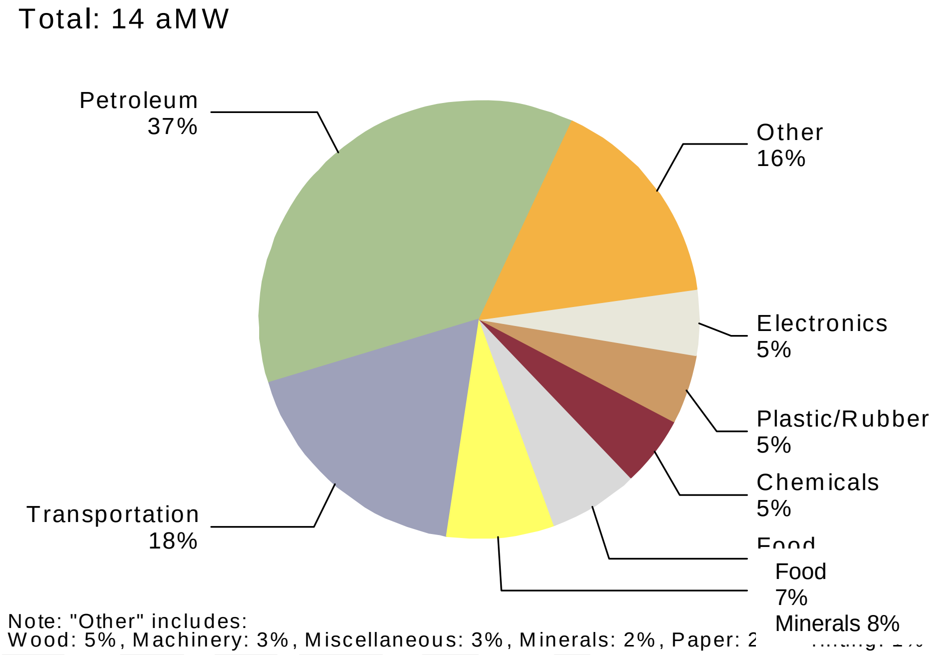
Table 20. Commercial Sector Gas Energy-Efficiency Potential by End Use (Million therms in 2029)

			Achievable Technical Potential					
End Use	Baseline Sales	Technical Potential	Under $0.95/therm	Under $1.20/therm	Under $1.50/therm	Under $2.00/therm	Under $2.50/therm	All Costs
Cooking	56.2	4.0	0.4	1.5	2.2	2.2	2.3	2.7
Dryer	24.1	-	-	-	-	-	-	-
Miscellaneous End Uses	6.3	-	-	-	-	-	-	-
Pool Heating	2.5	0.5	0.3	0.3	0.3	0.3	0.3	0.3
Space Heating	255.8	94.7	13.9	17.4	19.2	24.5	30.4	59.9
Water Heating	94.7	32.5	8.4	10.9	12.2	13.0	13.7	20.8
Total	440	132	23	30	34	40	47	84

Industrial Sector - Electricity

Technical and achievable technical energy-efficiency potentials were estimated for major end uses within 17 major industrial sectors. For a list of these industries, along with baseline information, see Volume II, Appendix C. Across all industries, achievable technical potential totals approximately 14 aMW over the 20-year planning horizon, corresponding to an 11% reduction of forecasted 2029 industrial consumption. Note that in the industrial sector, most of the achievable technical potential is included in the lower-cost bundles.

Figure 15. Industrial Sector Electric Achievable Technical Potential by Segment



The majority of electric economic potentials in the industrial sector (63%) are attributable to efficiency gains in process efficiency (heating, cooling, compressed air, etc.), followed by HVAC improvements (14%) and motor system improvements (mainly fans and pumps). A small amount of additional potential exists for lighting and other facility improvements (Figure 16 and Table 21).

Figure 16. Industrial Sector Electric Achievable Technical Potential by End Use

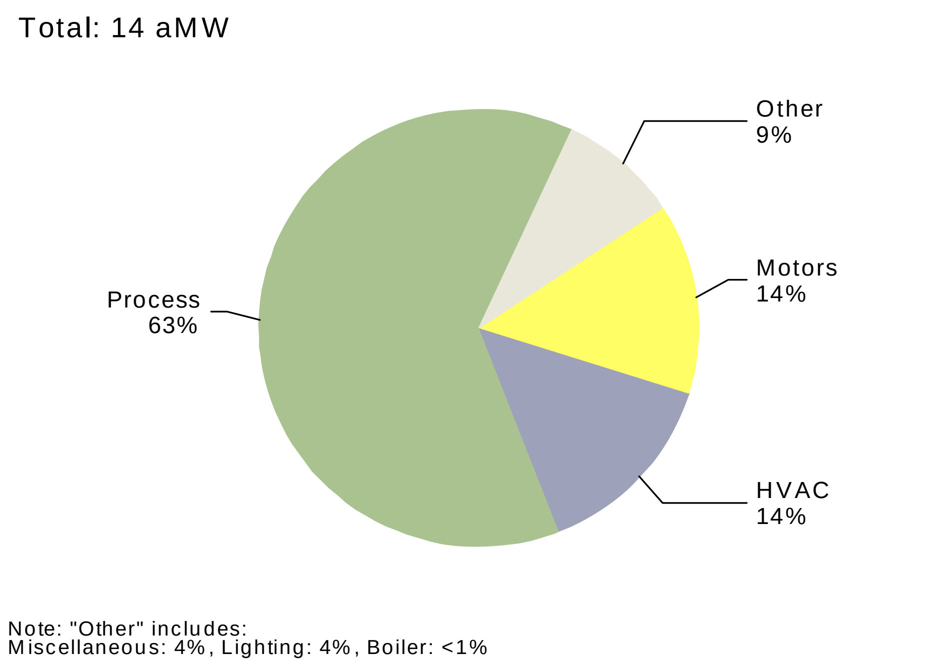


Table 21. Industrial Sector Electric Energy-Efficiency Potential by End Use (aMW in 2029)

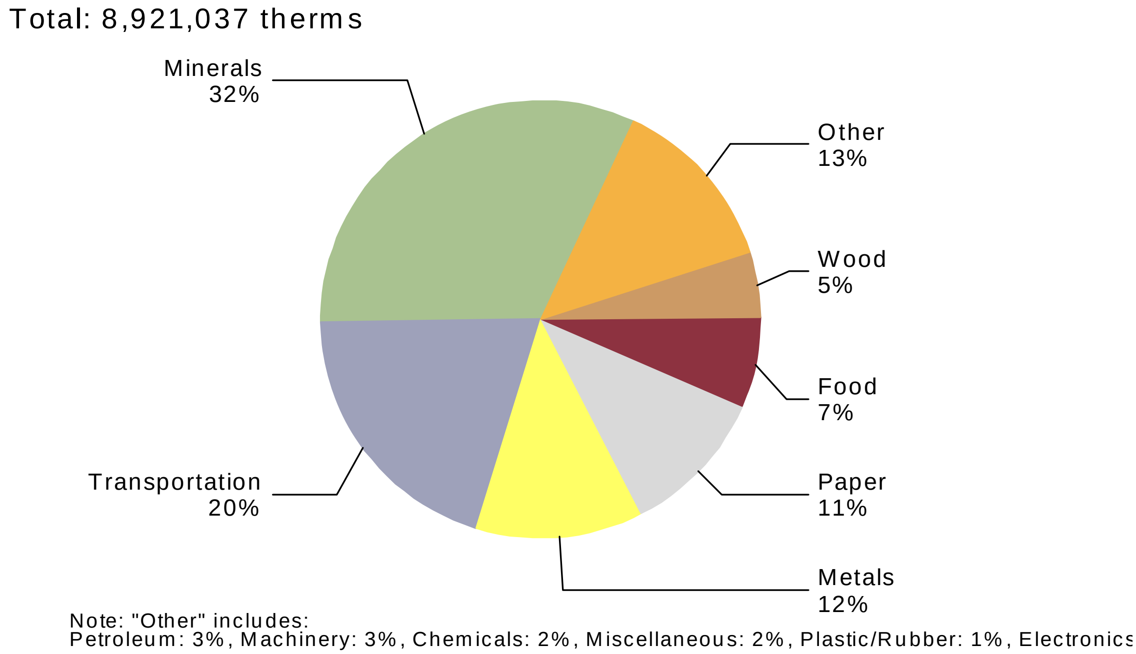
End Use	Baseline Sales	Technical Potential	Achievable Technical Potential Under $50/MWh	Under $91/MWh	Under $120/MWh	Under $138/MWh	Under $189/MWh	Under $282/MWh	All Costs
HVAC	14.3	2.4	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Lighting	9.9	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Process Cooling	8.5	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Process Electro-Chemical	2.4	-	-	-	-	-	-	-	-
Process Heating	10.8	2.3	1.9	2.0	2.0	2.0	2.0	2.0	2.0
Process Motors Air Compression	14.7	3.8	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Process Motors Fans	10.7	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Process Motors Other	35.9	3.4	2.8	2.9	2.9	2.9	2.9	2.9	2.9
Process Motors Pumps	22.1	1.5	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Process Motors Refrigeration	6.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	135	17	14	14	14	14	14	14	14

Industrial Sector—Natural Gas

Most industrial processes and end uses use electricity, and, therefore, the industrial sector represents an extremely small portion of natural gas baseline sales and potential. Across all industries, achievable technical potential totals approximately 9,00,000 therms over 20 years. Though this represents 17% of forecasted 2029 industrial sales, it only accounts for 3.5% of the achievable technical potential across the three sectors.

Due to the nature of industries using natural gas in PSE's service territory, over half of the achievable technical potential lies in minerals (32%) and transportation (20%). As Figure 17 shows, there are also substantial savings opportunities in metals (12%), paper (11%), and food (7%).

Figure 17. Industrial Sector Gas Achievable Technical Potential by Segment



Almost 80% of baseline consumption is in boilers and process heating; thus, these end uses account for almost 86% of the achievable technical potential. The remaining potentials are in HVAC improvements and other (non-heating) process improvements (Figure 18 and Table 22**).**

Figure 18. Industrial Sector Gas Achievable Technical Potential by End Use

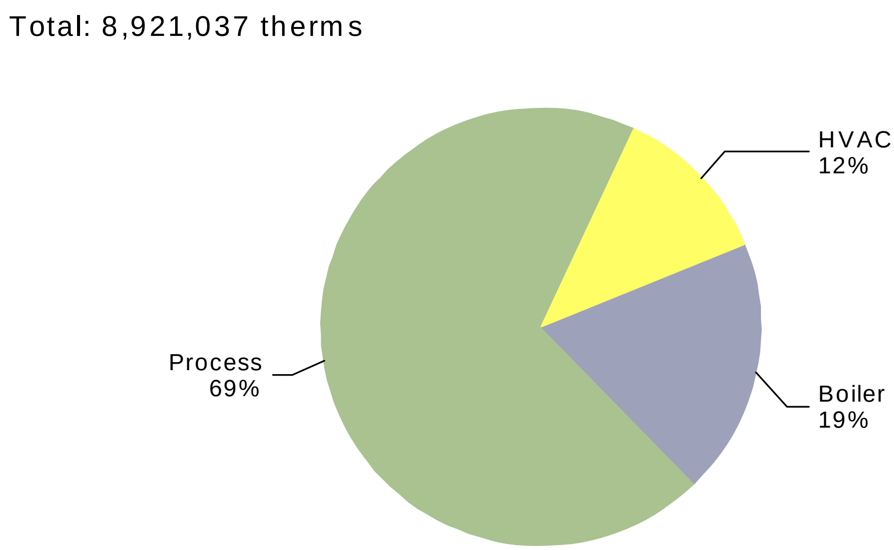


Table 22. Industrial Sector Gas Energy-Efficiency Potential by End Use (million therms in 2029)

End Use	Baseline Sales	Technical Potential	Achievable Technical Potential Under $0.95/therm	Under $1.20/therm	Under $1.50/therm	Under $2.00/therm	Under $2.50/therm	- All Costs
Boiler	15.3	2.2	1.7	1.7	1.7	1.7	1.7	1.7
HVAC	6.9	1.4	1.0	1.0	1.0	1.0	1.0	1.1
Process Heat	27.8	8.0	5.9	6.0	6.0	6.0	6.0	6.0
Process Other	3.6	0.2	0.1	0.1	0.2	0.2	0.2	0.2
Total	54	12	9	9	9	9	9	9

3. Fuel Conversion Potentials

Scope of Analysis

In the context of this study, "fuel conversion" refers to electricity saving opportunities involving substitution of natural gas for electricity through replacement of space heating systems, water heating equipment, and appliances. Fuel conversion potentials were examined for existing residential single-family homes, existing and new commercial buildings, and new multifamily structures in PSE's electric service area. For existing customers, conversion potentials were analyzed regardless of whether the customer was within PSE gas territory or Cascade Natural Gas territory. For new construction, only PSE combined territory (areas where PSE serves both electricity and natural gas) was considered. Four end uses were include in the analysis for single- and multifamily homes: (1) space heating; (2) zonal heating; (3) water heating; and (4) appliances (clothes dryer and cooking range). For commercial buildings, only space and water heating end uses were analyzed.

Methodology

The methodology for determining fuel conversion potential consisted of four steps:

1. Evaluate alternative technologies in terms of their life cycle costs (including full fixed installation and ongoing O&M expenses) and benefits as measured in terms of the value of displaced electricity.

2. Estimate technical potentials by determining the number of potential customers and applicable end uses.

3. Conduct survey of single-family homes in PSE electric territory to determine customer interest in fuel conversion.

4. Calculate annual achievable technical potential based on realizable percentage of technical potential and assumed resource acquisition rate.

Summary of Findings

Measures Considered

The analysis of fuel conversion considered opportunities in four major end uses in single-family dwellings: central heating, room heating, water heating, and appliances (clothes dryer and cooking range). Applicable measures and their assumed technical specifications are shown in Table 23.

Examination of room (or zonal) heating assumed conversion to strictly similar gas-fired equipment such as gas wall heaters (rather than central systems) for existing buildings. For new construction, central systems are assumed. Clothes dryers and cooking ranges were the only appliances considered in the study. Although the range of efficiencies for dryers tends to be narrow, a moisture sensor can be installed that will automatically shut off the dryer once the moisture level drops below a certain level. This can result in a 15% decrease in energy usage over a standard dryer due to reduced run-time.[2] Similarly, there are minor differences in the efficiency level of ranges. However, a 20% energy savings can be achieved by using a convection oven.[3] These measures, aside from wall heaters, are equivalent to those used for the energy efficiency analysis and detailed descriptions can be found in Volume II, Appendix B. Wall heaters are natural-gas powered room space heaters.

Table 23. List of End Uses and Measures Used

End Use	Gas Measure	Electric Baseline
Space heating	90 AFUE condensing furnace	Electric furnace
Room heating	84% efficient wall heater	Electric wall/ baseboard
Water heating	EF=0.80 storage water heater EF=0.82 tankless water heater	Electric water heater
Appliances	Gas dryer w/ moisture sensor Convection gas range	Electric dryer w/ moisture sensor Convection electric range

Gas Availability

Gas availability and its implications in terms of service extension costs is an important consideration in determining the potential for fuel conversion. This availability varies by sector. Figure 19 and Figure 20 give the breakout by segment for the single-family and multifamily segments. The fuel conversion potential for the single-family segment targets existing customers, while the multifamily conversion targets new construction. The new construction market size is cumulative over 20 years. Note that the potential market size accounts for current measure saturation. For example, some existing single-family homes already have a gas water heater. Those customers are not considered for water heater conversion. In addition, the potential market size for new construction excludes the percentage of customers that have historically included gas systems.

Residential

For existing single-family residential customers, data from several sources, including PSE's 2008 Residential End Use Survey (REUS) were used to determine availability. PSE currently serves gas to approximately 50% of single-family homes in its electric service area. As these customers use at least one piece of gas-using equipment (generally a gas furnace), they are considered candidates for only *additional* gas-using equipment, without imposing additional line extension costs. In addition, consideration was given to differing size ranges of single-family

[2] http://www.aceee.org/consumerguide/topwash.htm

[3] http://www.aceee.org/consumerguide/cooking.htm A convection oven includes a fan within the oven cavity that results in air circulation around the food, increasing overall heat transfer to the food. This allows for lowered oven temperatures and shortened cooking times.

homes, given that larger homes are likely to use more energy for space heat. Homes sizes analyzed were 1,800, 2,100 and 2,400 square feet.

Another portion of the fuel conversion technical potential is attributable to extension of service to existing, electric-only customers or new multifamily customers. The REUS results have shown about 17% of existing single-family residential electric customers are within PSE's gas service area, but do not have gas hookup. The remaining 33% of electric customers are in another utility's gas service territory.

For the multifamily segment, a previous residential survey (2004 Residential Energy Study) was used to determine the distribution of market share as the more recent REUS had only a small sample of multifamily homes. For new multifamily customers, approximately 14% are in PSE combo territory.

Based on the latest data available from PSE, delivery of gas service to these customers would depend on whether they are on a gas main (24%), or require a short (12%), medium (24%) or long (64%) extension if they are off main. Short extensions are assumed to be around 50 feet, medium extensions around 300 feet, and long extensions 500 feet. Customers requiring long extensions were excluded from the analysis as being too economically and technically impractical.

Figure 19. Single-Family Customers Available for Fuel Conversion

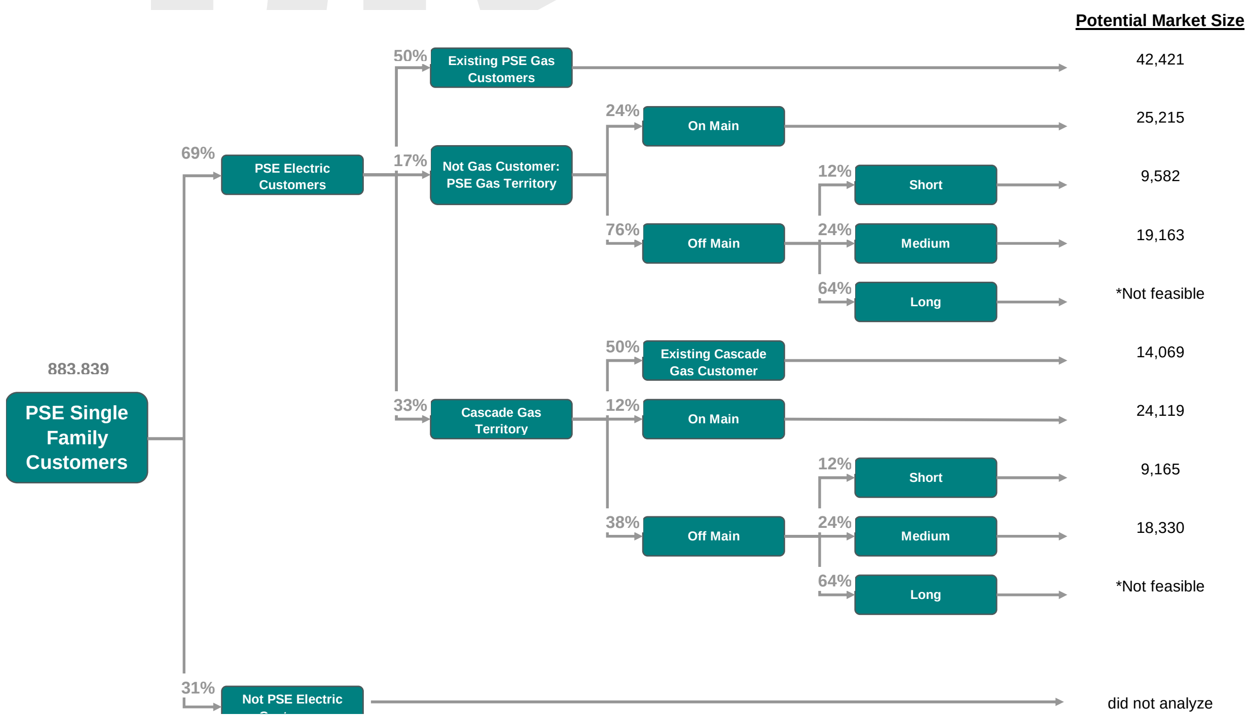
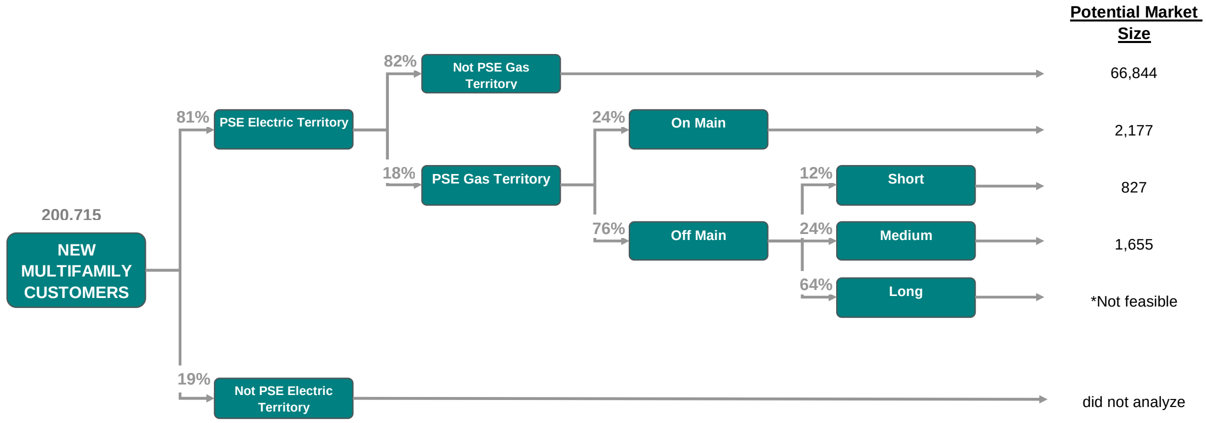


Figure 20. Potential New Multi-Family Customers (over 20 years)



Commercial

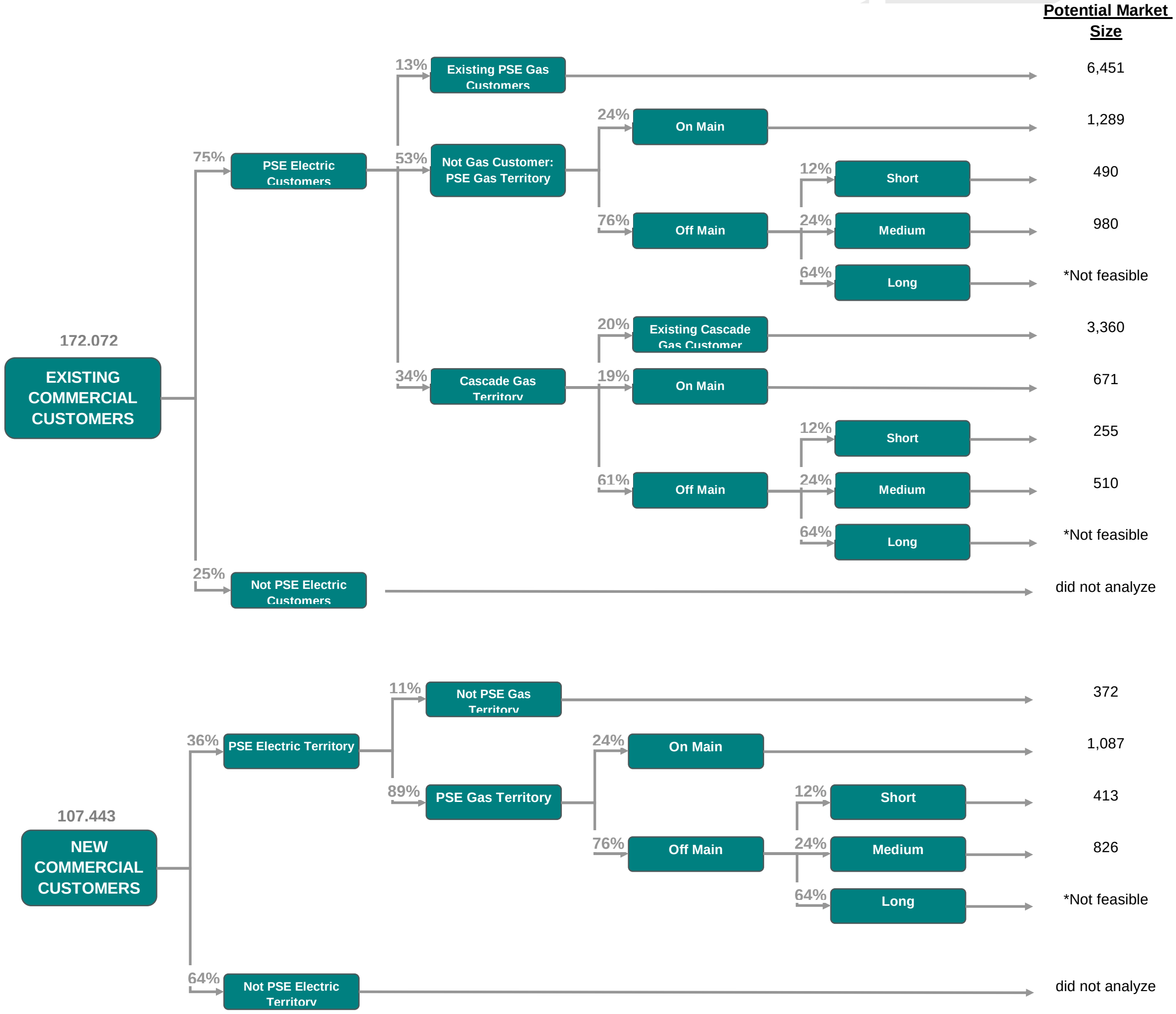
In the commercial sector, conversion potentials from both existing and new construction vintages were estimated. Data from the 2008 Commercial Building Stock Assessment (CBSA), coupled with PSE's non-residential database, provided the market shares by territory and end use. Of existing customers, approximately 40% of the current electric-only customers are in PSE gas territory. For new customers, approximately 32% are expected to be in the combo service territory. The customer breakout is shown in Figure 21. The new construction market size is cumulative over 20 years. Again, note this potential market size only includes customers who do not already have gas water heaters (for existing gas customers) and who are not expected to install a gas line (for new customers).

Conversion Costs and Benefits

In analyzing conversion costs, the TRC was considered; that is, the assumed installed cost of the gas measure, including gas line extension costs was used. For electric-only customers, connecting a house to the gas main is assumed to require either a service-line extension (no charge) or a short or medium main extension (approximately $40/ft). Since it is expected current electric customers would at least install a gas furnace, the cost to add the gas line to the house is only added to the furnace costs. Other end uses will have an additional cost only for interior piping ($200 per piece of equipment, as determined through interviews with local HVAC contractors on PSE's Contract Referral Service List). Detailed assumptions on various cost elements are described in Volume II, Appendix D.

Conversion costs were estimated based on electric and gas avoided costs and the assumed levels of unit energy consumption (UEC), consistent with those used in the energy-efficiency analysis described in Section 2. Avoided cost benefits were calculated from a net present value of the first-year electric ($/kWh) or gas ($/therm) avoided cost data for the different end-use load shapes and measure lives. Electric UECs (kWh/yr) and gas UECs (therms/year) used in the energy-efficiency model for existing single-family and new multifamily homes were used for baseline values. For simplicity, commercial buildings were modeled assuming an energy consumption that was the weighted average of all segments.

Figure 21. Commercial Achievable Technical Potential by Vintage



Resource Potentials

Technical Potential

Fuel conversion technical potentials were calculated by assuming all applicable customers and end uses are converted. At the meter, the technical potential was found to be 174 aMW. Acquisition of the indicated electricity savings would, however, result in increased gas consumption at the meter of about 107 million therms by 2029.

Achievable Technical Potential

A survey of residential customers was conducted to help determine the willingness of customers to switch from an electric heating system to a gas heating system. Details on the survey, including the survey instrument and tabulated results, can be found in Appendix A.3. The survey, administered to 318 PSE electric-only customers, provided an estimate of achievable technical potential as a function of rebate level. Additionally, participants were asked about their general understanding of the costs and benefits of conversion. The sample size was designed to obtain 90% confidence/10% precision for each proposed rebate level.

Based on this survey, approximately 63% of respondents indicated they would be likely or highly likely to convert from electric to gas space heating, if the utility were to pay 100% of the cost. As such, 63% of the technical potential is used to determine the achievable technical potential. Due to the lack of similar data, the same percentage was used for the commercial sector. Of those who would be interested in converting their furnace to a gas unit, nearly 70% would convert a water heater as well.

Based on the results of the survey and previous PSE experience, it is assumed, within the residential sector, of the new gas customers that convert a space heater, 70% will also convert a water heater, and 5% will convert a range and/or dryer. For existing gas customers, all will convert a water heater, and 5% will convert a range and/or dryer. Similar percentages are assumed for the water heating conversions in the commercial sector.

The total achievable technical electric savings potential of fuel conversion in year 20 for residential, single-family homes was estimated at 37 aMW, corresponding to an increase in gas use of 19 million therms, as measured at the meter. For multifamily homes, the potential electric savings would be 16 aMW and increased gas use would be 12 million therms. Finally, for the commercial sector, the achievable technical electric savings potential in year 20 would be 12 aMW, corresponding to an increase in gas use of 8.9 million therms, as measured at the meter. A summary of these potentials is provided in Table 24, and the achievable technical potential by building type is provided in Table 25. As shown in Figure 22, deployment of fuel conversion resources begins with a slow growth period during the first three years, allowing for program development, followed by a strong, linear growth rate for the remainder of the planning horizon.

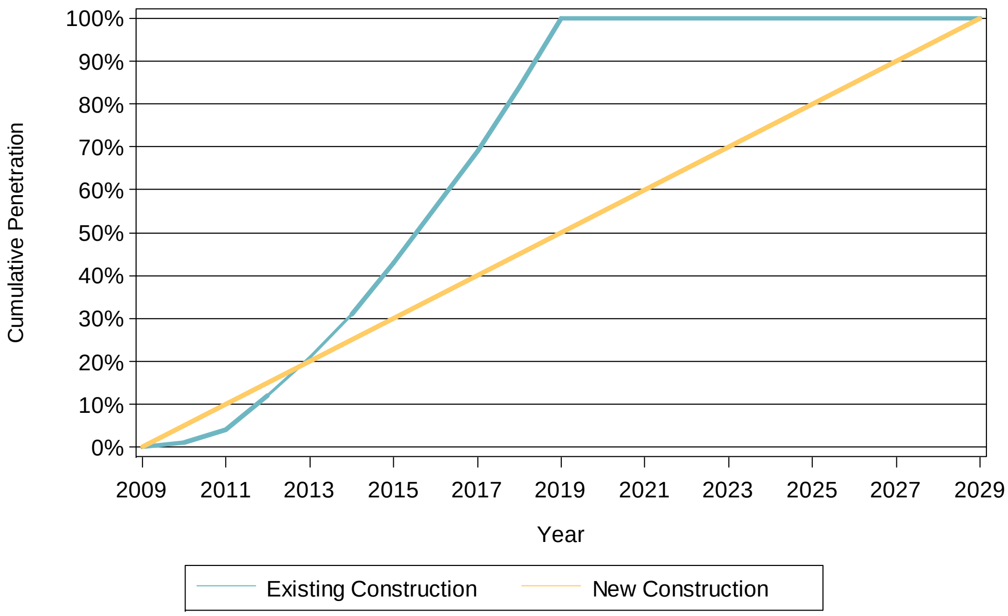
Table 24. Summary of Fuel Conversion Potentials

	Electric-Only Customers		Existing Gas Customers	Total
	PSE Gas Territory	Cascade Natural Gas Territory		
Technical Potential				
Electric Savings (aMW)	53.4	82.5	37.9	173.8
Additional Gas Usage (million therms)	32.9	53.5	20.7	107.1
Achievable Technical Potential				
Electric Savings (aMW)	20.3	29.8	15.2	64.9
Additional Gas Usage (million therms)	12.6	20.0	7.4	40.0

Table 25. Achievable Technical Potential by Building Type

	Electric-Only Customers: PSE Gas Territory	Electric-Only Customers: Cascade Natural Gas Territory	Existing Gas Customers	Total
Single Family				
Electric Savings (aMW)	11.2	10.3	15.0	36.1
Additional Gas Usage (million therms)	6.1	5.8	7.2	19.1
Multifamily				
Electric Savings (aMW)	0.6	15.7	NA	16.3
Additional Gas Usage (million therms)	0.4	11.6	NA	12.0
Commercial				
Electric Savings (aMW)	8.5	3.7	0.2	12.5
Additional Gas Usage (million therms)	6.1	2.6	0.1	8.9

Figure 22. Assumed Ramp Rate for Fuel Conversion



4. Demand Response Potential

Scope of Analysis

Demand response (DR) or load reduction programs, focused on reducing a utility's capacity needs, are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs are designed to help reduce peak demand, promote improved system reliability, and, in some cases, may lead to the deferment of investments in delivery and generation infrastructure. Objectives of DR may be met through a broad range of price-based (e.g., time-varying rates and interruptible tariffs) or incentive-based (e.g., direct load control) strategies. In this assessment, the following demand-response strategies were analyzed:

1. ***Direct Load Control*** (DLC) programs allow a utility to remotely interrupt or cycle electrical equipment and appliances at a customer's facility. In this study, the assessment of DLC program potential is analyzed for three programs in the residential sector: central electric heating (including heat pumps) and electric water heating combination program; room heating and electric water heating combination program; and central AC (including heat pumps) and water heating combination program. For large commercial customers, DLC is modeled, using integration with existing energy management systems (EMS), to have additional controls on lighting, HVAC, and plug loads. The large DLC program is included for summer and winter demand reduction. This analysis assumes such programs target commercial customers with average monthly demand greater than 500 kW.

2. ***Interruptible Tariffs*** refer to contractual arrangements between the utility and its customers, who agree to curtail or interrupt their loads in whole or part for a predetermined period when requested. In most cases, mandatory participation is required once the customer enrolls in the program; however, these programs may include provisions for customers to exercise an economic buy-through of a curtailment event. Incentives are paid regardless of the quantity of events called each year (less any penalties associated with an event buy-through). This analysis assumes such programs target nonresidential customers with average monthly loads greater than 500 kW.

3. ***Demand-Bidding or Demand Buy-Back*** programs offer payments to customers for voluntarily reducing their demand at the utility's request. The buyback amount generally depends on market prices published by the utility in advance of the event, coupled with the customer's ability to curtail use during the hours load curtailment is requested. The reduction level achieved is verified using an agreed-upon baseline usage level specific to the participating customer. This analysis assumes such programs target nonresidential customers with loads greater than 200 kW.

4. ***Critical Peak Pricing*** (CPP) or extreme-day pricing refers to programs aiming to reduce system demand by encouraging customers to reduce their loads for a limited number of hours during the year. During such events, customers have the option of curtailing their usage or paying substantially higher-than-standard retail rates. CPP programs integrate a pricing structure similar to a TOU (time of use) program with the distinction of more

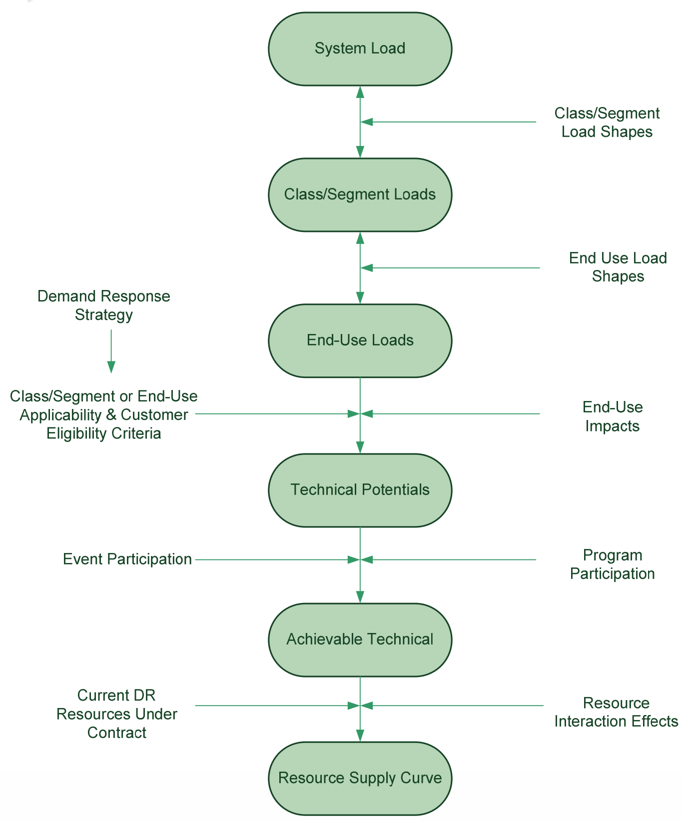
extreme pricing signals for the critical events. For the residential sector, it is assumed enabling technology is installed (e.g., smart thermostats).

Program options listed above are based on a thorough review of literature cataloging and classifying DR strategies offered by utilities and regional transmission organizations across the country. For each program offering, data were collected on the offering's main features, such as objectives, program periods, eligibility criteria, curtailment event triggers, incentive structures, and technology requirements. These program options are described in more detail later in this section.

Methodology

The methodology for estimating DR potential was based on a combined "top-down"/"bottom-up" approach. Cadmus's DRPro® Model provided the basic framework for this analysis. As shown schematically in Figure 23, the approach begins with utility system loads, disaggregating them into sector, segment, and applicable end uses. For each DR program (or program component), potential technical impacts are calculated for all applicable end uses. The end-use load impacts are aggregated to obtain estimates of technical potentials. Market factors such as probabilities of program and event participation then are applied to technical potentials to obtain estimates of achievable technical potentials. The methodology for calculating technical and achievable technical potentials is described in greater detail below.

Figure 23. Schematic Overview of Demand Response Assessment Methodology



Estimating Technical Potential

DR technical potentials are first estimated at the end-use level, and then are aggregated to market segment, sector, and system levels. This approach was implemented in the following four steps.

1. **Define customer sectors, market segments and applicable end uses**. The first step in the process involved defining appropriate sectors, market segments, and end uses within each segment for each utility. We used the following classification scheme for demand response:

   Customer classes/sectors: residential, commercial, and industrial.

   Market segments:

   1. Residential: single-family, multifamily, and manufactured homes.
   2. Commercial: education, grocery, health, lodging, office, restaurant, retail, warehouse, and other commercial.
   3. Industrial: food manufacturing, primary metal manufacturing, paper manufacturing, plastics rubber manufacturing, chemical manufacturing, nonmetallic mineral products, industrial machinery, fabricated metal products, printing related support, transportation equipment manufacturing, electronic equipment manufacturing, wood product manufacturing, miscellaneous manufacturing, petroleum manufacturing, computer manufacturing, and waste water and water treatment.

   Large accounts: the largest nonresidential customers were researched for each utility, and unique segments were created as necessary to appropriately account for their characteristics.

   End uses: space heating, room heating, central cooling, water-heating, lighting, plug loads, process (industrial), etc.

2. **Screen customer segments and end uses for eligibility**. This step involved screening end uses for applicability of specific DR strategies. For example, hot water loads in hospitals and cooking loads were excluded (if no backup generation was available).

3. **Compile utility-specific sector/end-use loads**. Reliable estimates of DR potential depend on the correct characterization of sector, segment, and end-use loads. Load profiles were developed for each end use. Contributions to system peak for each end use were estimated based on end-use load shapes.

4. **Estimate technical potential**. Technical potential for each DR program is assumed to be a function of customer eligibility in each class, affected end uses in that class, and the expected impact of the strategy on the targeted end uses. Analytically, technical potential (*TP*) for a demand-response program *(s)* is calculated as the sum of impacts at the end-use level (*e*), generated in customer class (*c*), by the program; that is:

   $$TP_s = \sum TP_{sce}$$

   and

   $$TP_{sce} = LE_{cs} \times EUS_{cs} \times LI_{se}$$

   where,

LE_{cs} (load eligibility) represents the percent of customer class loads that are eligible for strategy s

EUS_{cse} represents the share of end use e in customer class c eligible for DR strategy s

LI_{se} (load impact) is percent reduction in end-use load e resulting from program s

Load eligibility thresholds were established by calculating the percent of load by customer class and market segment that met minimum (or maximum) load criteria for each program, based on program filings.

Estimate Achievable Technical Potential

As discussed above, estimates of expected load impacts resulting from various DR programs (LI_{se}) are based on a comprehensive review and assessment of DR program impacts offered by utilities throughout the United States. Program participation indicates the percent of participating customers, while event participation summarizes the percent of program participation that will participate in any one event. Note that, as with other resources, no economic screen was performed in this study.

Develop Supply Curves

Achievable technical potentials were determined based on applicable program costs along with event participation and program participation. To add additional perspective, achievable technical potentials for each DR program strategy were combined with per-unit resource costs to produce "cumulative" resource supply curves. The supply curves show price/quantity relationships at the aggregate level. Interactive program impacts were not taken into consideration.

Program implementation costs were researched and documented by our engineering staff. All categories of costs were considered, generally falling into two categories:

1. Fixed program expenses, such as program infrastructure, administration, maintenance, and communication.

2. Variable costs, such as incentive payments to participants, customer-site hardware, customer-specific marketing/recruiting, and metering.

Summary of Resource Potential

Table 26 and Table 27 present estimated resource potentials for all DR resources for the residential, commercial, and industrial sectors for summer and winter. Achievable technical potential is highest in the residential sector due to the direct load control programs. As noted above, however, the analysis does not account for program interactions and overlap; thus, the total technical and achievable technical potential estimates are not fully attainable.

Table 26. Technical and Achievable Technical Potential (MW in 2029) - Winter

Sector	2029 Sector Peak	2029 Technical Potential	2029 Achievable Technical Potential	Achievable Technical Potential As Percent of 2029 Sector Peak
Residential	3,577	1,729	170	5%
Commercial	2,901	135	14	<1%
Industrial	130	43	5	4%
Total	6,608	1,909	178	3%

Note: Individual results may not sum to total due to rounding.
Note: Interactions between programs have not been taken into account.
Note: Residential technical potential and achievable technical potential for residential potential for direct load control do not include AMR converted to AMI or existing AMI due to overlap with no AMR meter installed.

Table 27. Technical and Achievable Technical Potential (MW in 2029) - Summer

Sector	2029 Sector Peak	2029 Technical Potential	2029 Achievable technical Potential	Achievable Technical Potential As Percent of 2029 Sector Peak
Residential	2,428	676	48	2%
Commercial	2,334	136	14	1%
Industrial	157	43	5	3%
Total	4,919	855	68	1%

Note: Individual results may not sum to total due to rounding.
Note: Interactions between programs has not been taken into account.
Note: Residential technical potential and achievable technical potential for direct load control do not include AMR converted to AMI or existing AMI due to overlap with no AMR meter installed.

Resource Costs and Supply Curves

Utility costs for DR program options can vary significantly. Where possible, cost estimates were developed for each program option based on data available from comparable programs across the region and nation. In certain cases, this level of specificity was difficult to establish as many utilities do not track or report program costs in sufficient detail. For example, development of a new DR program can be a significant effort for a utility, requiring enrollment, call centers, program management, load research, development of evaluation protocols, changes to billing systems, and marketing. Background research on utilities across the nation indicated large variations in direct program costs. Based on the experiences of utilities, this analysis assumed $400,000 as a "typical" first cost for program development for large-scale residential sector programs and $200,000 for nonresidential customer programs.

In developing estimates of per-unit costs, program expenses were allocated annually over the expected program life cycle (20 years), then were discounted by PSE's weighted average cost of capital to estimate the total discounted cost. The ratio of this value and the average annual kW reduction produced the levelized per-kW cost for each resource. Additionally, attrition rates were used to account for program turnover due to changes in electric service (i.e., housing stock turnover) and program drop-outs. The basic assumption for this analysis was an attrition rate of 7% for the residential sector and 2% for the commercial sector, based on averaged values experienced by other utilities such as PacifiCorp. Attrition requires reinvestment of new customer costs, including technology, installation, and marketing. In addition, the analysis assumed a measure life for the installed technology, and all costs were adjusted upward by $60,000 for residential and $50,000 for nonresidential programs to account for administrative expenses.

Table 28 displays the per-unit ($/kW-year) costs by season for the estimated achievable technical potential. The first cost associated with starting a DR program was included only for the winter programs. Summer programs and the DLC program for room heating and water heating was considered to be an addition to the existing winter and DLC space heating and water heating programs as the infrastructure for these programs already existed.

The interruptible tariffs program for large non-residential customers was estimated to be the least expensive option, with a levelized cost of $57/kW a year for winter, while demand bidding is the least expensive option for summer, with a levelized cost of $11/kW-year.[4]

Table 28. Levelized Costs and Achievable Technical Potential (MW in 2029)

	Winter		Summer	
Strategy	Achievable Technical Potential (MW)	Levelized Cost ($/kW)	Achievable Technical Potential (MW)	Levelized Cost ($/kW)
Direct Load Control (DLC)				
Residential (SH and WH/ AC and WH) AMR Meter	47	$74	8	$177
Residential (RH and WH) AMR Meter	54	$71	NA	NA
Residential (SH and WH/ AC and WH) AMR Meter Converter to AMI Meter	47	$93	8	$224
Residential (RH and WH) AMR Meter Converter to AMI Meter	54	$85	NA	NA
Residential (SH and WH/ AC and WH) Existing AMI Meter	47	$81	8	$195
Residential (RH and WH) Existing AMI Meter	54	$76	NA	NA
Critical Peak Pricing (CPP) Residential	69	$83	40	$138
Direct Load Control (DLC) Large Commercial	24	$126	23	$95
Interruptible Tariffs (Large Non-Residential	14	$57	15	$49
Demand Bidding (Medium and Large Non-Residential)	2	$83	2	$11

Note: Direct Load Control RH & WH and all summer programs do not have a first cost included due to the cost included to start the program being incorporated in winter programs or DLC SH & WH. Levelized cost would be higher if the program was implemented without the inclusion of the winter program.

[4] This levelized cost would only incur if the demand bidding program is also run for the winter season, due to the start-up cost being included only in the winter season.

Supply curves were constructed from quantities of estimated market resource potential and per-unit costs of each resource option. The capacity-focused supply curves, shown in Figure 24 and Figure 25, represent the quantity of each resource (cumulative achievable technical MW) that can be achieved at or below a given cost in the winter and summer, respectively. The DLC residential program chosen for display in each of the figures below is the AMR meter option. This type of meter strategy was chosen because it is the most popular strategy and has the lowest levelized cost. Note that in the winter, although it costs $81/kW to obtain 64 MW, an additional 178 MW is available if the cost threshold is increased to $85/kW. Program interactions were not accounted for in this study.

Figure 24. Winter Supply Curve (Cumulative MW in 2029)

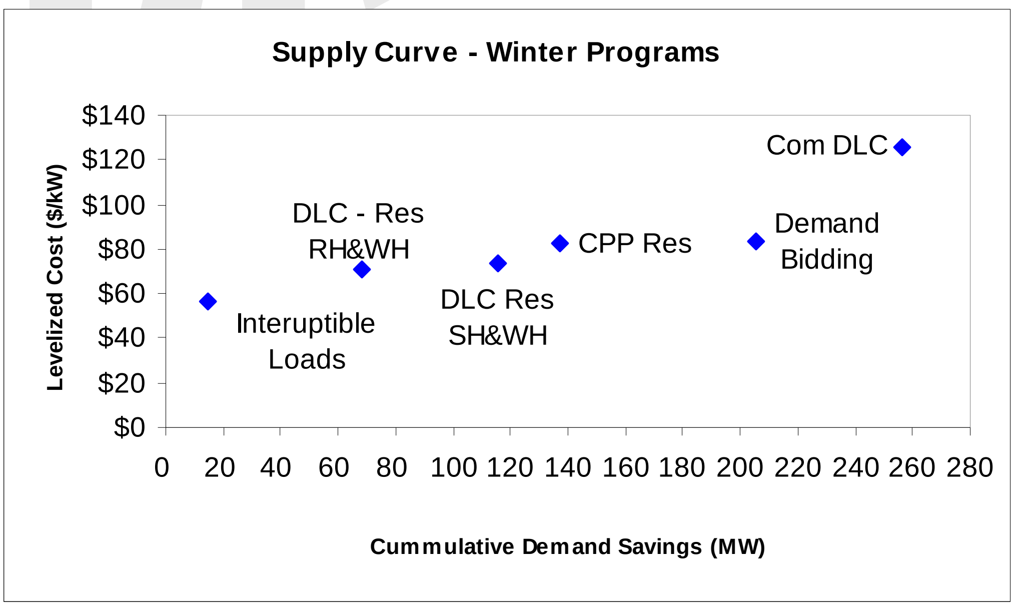
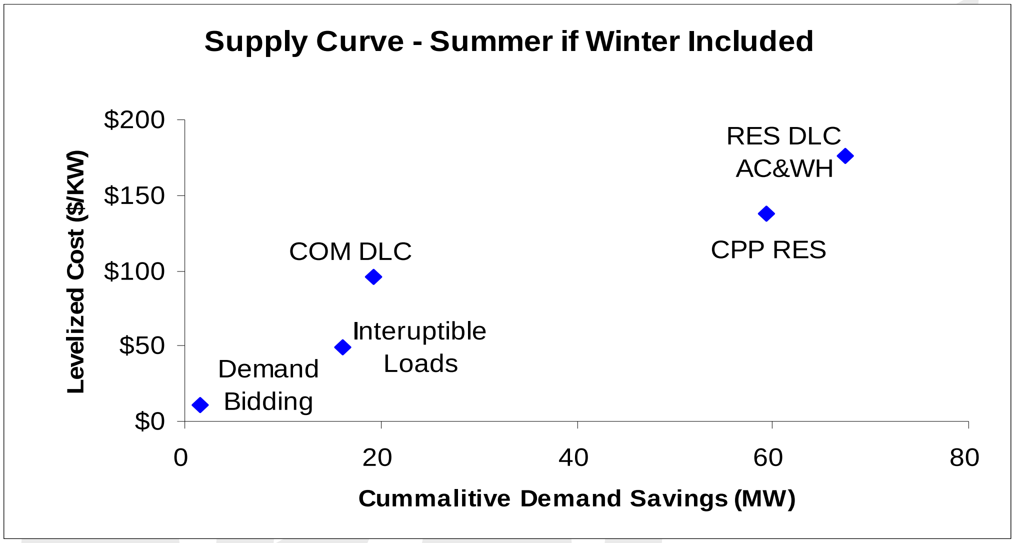


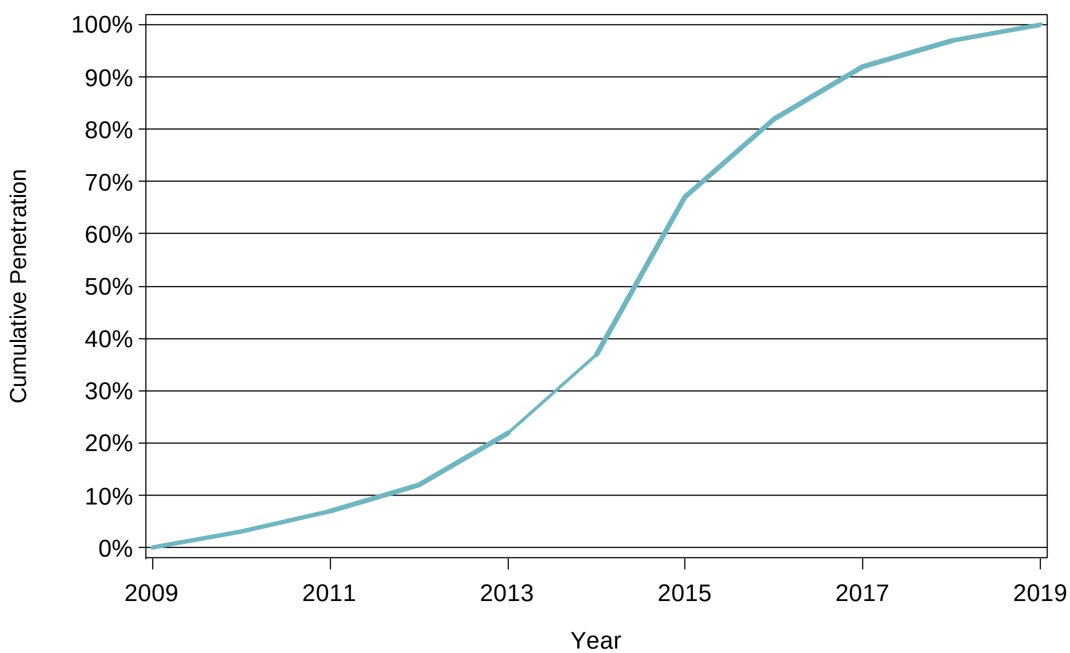
Figure 25. Summer Supply Curve (Cumulative MW in 2029)



Resource Acquisition Schedule

Each program option has an associated ramping rate (Figure 26). The general logic holds that it requires 10 years to grow a new program from inception to full potential, and the first three years have relatively slow growth; as more customers become aware of the DR programs, the participation rate will increase (years four through eight). Years nine and ten have a slow rate of increase due to the program reaching the maximum number of participating customers. After Year 10, the program levels increase at the rate of sales growth (by sector) only.

Figure 26. DR 10-Year Ramp Rate



Detailed Resource Potentials

Direct Load Control

DLC programs are designed to interrupt specific end-use loads at customer facilities through utility-directed control. When deemed necessary, the utility is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers do not have to pay for the equipment or installation of control systems and are given incentives that are usually paid through monthly credits on their utility bills. For this type of program, receiver systems are installed on the customer equipment to enable communications from the utility and to execute controls. Historically, DLC programs have become mandatory once a customer elects to participate; however, voluntary participation is now an option for some programs with more intelligent control systems and override capabilities at the customer facility.[5]

Recently, DLC of air-conditioning has emerged as the most common load management program type. In addition to reviewing meta-studies on DLC, we researched many key utility programs, including Florida Power and Light, Nevada Power, Sacramento Municipal Utility District, Southern California Edison, Pacific Gas and Electric, Austin Energy, Consolidated Edison, Long Island Power Authority, Idaho Power, Xcel-MN, PacifiCorp, Alliant, MidAmerican, and Wisconsin Public Service.[6]

This analysis covers residential and commercial DLC programs and reviewed multiple types of available end uses, with four program options:

1. Residential central heating and water heating.
2. Residential room heating and water heating.
3. Residential air-conditioning and water heating.
4. Large commercial programs.

Values used in modeling have been standardized based on DR program research.

For the residential DLC programs, three different types of meter approaches were evaluated. A receiver attached to the appliance allowing the machine to cycle or shut-off is required in all three cases. Currently, PSE has Automatic Meter Reading (AMR) meters installed. This type of technology does not allow for two-way communication. The utility can receive a signal from the meter but cannot send a signal to the meter.

1. AMR meter: Only a receiver installed on a specific appliance.

[5] Typically, penalties are associated with non-compliance or opt-outs.

[6] DOE. *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*. Report to Congress. February 2006.

2. AMR meter converted to Advanced Metering Infrastructure (AMI) meter (additional receiver attached to AMR meter to allow for two-way communication and data storage charge).

3. Existing AMI meter (data storage charge).

The first strategy is primarily chosen by most utilities, though there is a major drawback in that the utility does not receive confirmation that the appliance has actually shut off. As only a one-way communication receiver is attached to the appliance, no signal can be sent back to the utility to confirm the event. This is, however, the least expensive approach as one receiver would be the only additional cost.

The other two strategies are similar. Strategy two involves converting an existing AMR meter to an AMI. This would involve two additional charges: a two-way communication receiver ($150/meter) replacing the existing one-way communication receiver for the AMR meter; and a data storage charge ($15/customer). Strategy three assumes the meter is already an AMI, and the only additional charge would be the data storage charge. Although both of these strategies would be more expensive than the AMR meter approach, two major advantages could improve reliability and save money on evaluation studies:

1. Notification the equipment has shut off. Utilities have performed evaluation studies and determined not all receivers attached to appliances work properly. Using either of these two strategies would allow PSE to confirm the appliance shuts off and would allow PSE to replace any nonfunctional receivers without having to field-test every unit.

2. As an AMI meter is capable of producing interval data, an evaluation study would be significantly less expensive (no additional metering would be needed), and would involve actual metered data.

Space Heating and Water Heating (Residential)

Although residential DLC for air conditioning has been one of the most well-established programs in the nation (PacifiCorp, MidAmerican, Alliant, Florida Power and Light, Xcel Energy, etc.), a space heating DLC program is a relatively new idea with minimal data available through secondary research.

Table 29 shows the technical and achievable technical potential results for the PSE service territory, by customer class. If PSE were to offer this program, the levelized cost would be $85/kW-year with an AMR meter, $107 for an AMR converted to AMI, and $94 for an existing AMI meter.

Table 29. Residential DLC Space Heating and Water Heating: Technical and Achievable Technical Potential (MW in 2029)

Sector	Winter		
	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2029 Sector Peak
Residential	375	47	2%
Commercial	- - -	- - -	- - -
Industrial	- - -	- - -	- - -
Total	376	41	<1%

Utility incentives for residential DLC programs can vary widely, from a free programmable thermostat to a set incentive amount per month to a 15% discount on customers' summer electricity bills (which can sum to $50-$60 annually for many participants). Incentives for this analysis are set at $32/year for space heat cycling (50%) and $8 for water heating cycling (100%). Additional costs are assessed for this program, including: $30 per new customer of marketing; $7 for each existing customer for communications, replacement of technology every 15 years; $400,000 for program start-up; and an attrition rate (requiring reinvestment of new-customer costs) of 7% based on 5% change of service and 2% removals. Detailed assumptions are provided in Table 30.

Table 30. Assumptions for Residential DLC Space and Water Heating Potential

Program Concept	Assumptions
Customer Sectors Eligible	All Residential
End Uses Eligible for Program	Electric Central Heating (or Air-Source Heat Pump) and Electric Water Heater
Customer Size Requirements, if any	N/A
Summer Load Basis	N/A
Winter Load Basis	Top 20 Winter Hours

Inputs	Model Values	Model Assumptions
Annual Attrition (%)	7%	Studies have found 7% (composed of 5% change of service and 2% removals) from utilities, including RMP, Xcel, Eon US, SMUD, FP&L (removals range from 1%–3%).
Per Customer Impacts (kW)	1.8 Space Heating 0.5 Water Heating	Space Heating – Adjustment based on central AC savings from other utilities (PacifiCorp and Alliant). Water Heating – Reduction level for Alliant program. Adjustment of 0.2 to 0.5 made to account for part of winter load occurring in the morning during shower operation.
Total kW reduction per program	N/A	PSE does not currently offer this program.
Annual Administrative Costs (% of First-year Cost)	$60,000	An administrative adder of 15% was typically assumed for all residential program strategies (assuming that since 15% will be taken from a first cost of $400,000, the annual administrative cost will be $60,000).
Technology Cost	$150	$150 is indicated in the CEC report from 2004 (for the installed cost of ratio frequency load control devices). WH controls will require another switch, doubling this cost.
Marketing Cost	Space Heating $30 Water Heating $0	Marketing costs are set at $30 based on data available from other utilities. No additional marketing costs for water heaters.

Incentive (annual costs)	Space Heating $32 Water Heating $8	Incentives range from $30 to $35 for most utilities for one piece of equipment DLC program and $8 for additional equipment.
Communication Costs (per Customer Per Year)	$7	This value accounts for annual per-customer communication of a two-way transmission system.
Overhead: First Costs	$400,000	$200k for labor and $200k for IT.
Per Customer First Cost	Space Heating $180 Water Heating $150	Sum of technology cost plus marketing cost
Per Customer Ongoing	Space Heating $62 Water Heating $31	For Space Heating, ongoing costs are calculated from summing annual customer incentives, annual communication costs, and 15% of technology costs for repair and/or replacement of equipment.
Eligible Load (%)	100% of the Cooling Load	Eligible load is the percentage of customers eligible for this program.
Technical Potential (as % of Gross)	Space Heating 50% Water Heating 100%	The space heating program is modeled as a 50% cycling program. Due to the tank, water heating can be shut off for the entire event (100% reduction).
Program Participation (%)	Space Heating 35% Water Heating 2%	Of customers with space heating, the assumption is 35% of these customers will participate. All customers with electric space heating will also include water heating in the program.
Event Participation (%)	90%	It is assumed each customer will be allowed to miss one event a year.

Residential Room Heating and Water Heating

Similar to a central space heating DLC program, a room heating DLC program is a relatively new idea with minimal to no data available through secondary research.

Table 31 shows the technical and achievable technical potential results for the PSE service territory, by customer class. If PSE was to offer this program, the levelized cost would be $81/kW-year for AMR meter, $97 for AMR converted to AMI, and $87 for existing AMI meter.

Table 31. Residential DLC Room Heating and Water Heating: Technical and Achievable Technical Potential (MW in 2029)

Sector	Winter		
	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2029 Sector Peak
Residential	592	54	2%
Commercial	- - -	- - -	- - -
Industrial	- - -	- - -	- - -
Total	594	49	<1%

Detailed assumptions providing values and sources that derived potential and levelized costs are shown in Table 32.

Table 32. Assumptions for Residential DLC Room Heating and Water Heating Potential

Program Concept	Assumptions
Customer Sectors Eligible	All Residential

End Uses Eligible for Program	Electric Room Heating (baseboard) and Electric Water Heater
Customer Size Requirements, if any	N/A
Summer Load Basis	N/A
Winter Load Basis	Top 20 Winter Hours

Inputs	Model Values	Model Assumptions
Annual Attrition (%)	7%	Studies have found 7% (composed of 5% change of service and 2% removals) from utilities, including RMP, Xcel, Eon US, SMUD, FP&L (removals range from 1%–3%).
Per Customer Impacts (kW)	2.5 Room Heating 0.5 Water Heating	Room Heating – Adjustment based on central AC savings from other utilities (PacifiCorp and Alliant). Water Heating – Reduction level for Alliant program. Adjustment of 0.2 to 0.5 made to account for part of winter load occurring in the morning during shower operation.
Total kW reduction per program	N/A	PSE does not currently offer this program.
Annual Administrative Costs (% of First-year Cost)	$60,000	An administrative adder of 15% was typically assumed for all residential program strategies (assuming that since 15% will be taken from a first cost of $400,000, the annual administrative cost will be $60,000).
Technology Cost	$450	Assumes 3 baseboard units at $150. $150 is indicated in the CEC report from 2004 (for the installed cost of ratio frequency load control devices). WH controls will require another switch and result in doubling this cost.
Marketing Cost	Room Heating $30 Water Heating $0	Marketing costs are set at $30 based on data available from other utilities. No additional marketing costs for water heaters.
Incentive (annual costs)	Room Heating $32 Water Heating $8	Incentives range from $30 to 35$ for most utilities for one piece of equipment DLC program and $8 for additional equipment.
Communication Costs (per Customer Per Year)	$7	This value accounts for annual per-customer communication of a two-way transmission system.
Overhead: First Costs	$0	Charge occurs for set up on DLC Space and Water Heating.
Per Customer First Cost	Room Heating $480 Water Heating $150	Sum of technology cost plus marketing cost.
Per Customer Ongoing	Room Heating $62 Water Heating $31	For Space Heating, ongoing costs are calculated from summing annual customer incentives, annual communication costs, and 15% of Technology costs for repair and/or replacement of equipment.
Eligible Load (%)	100% of the Cooling Load	Eligible load is the percentage of customers eligible for this program.
Technical Potential (as % of Gross)	Room Heating 50% Water Heating 100%	The space heating program is modeled as a 50% cycling program. Due to the tank, water heating can be shut off for the entire event (100% reduction).
Program Participation (%)	Room Heating 35% Water Heating 2%	Of customers with space heating, the assumption is 35% of these customers will participate. All customers with electric space heating will also include water heating in the program.
Event Participation (%)	90%	It is assumed each customer will be allowed to miss one event a year.

Residential Central Air-conditioning and Water Heating

Residential DLC for a central AC system is one of the most well-established programs in the nation (PacifiCorp, MidAmerican, Alliant, Florida Power and Light, Xcel Energy, etc.).

Table 33 shows the technical and achievable technical potentials by customer class. If PSE was to offer this program, the levelized cost would be $177/kW-year for AMR meter, $224 for AMR converted to AMI, and $195 for existing AMI meter. The high levelized cost is due primarily to a small number of homes in PSE territory with Central AC.

Table 33. Residential DLC Air-conditioning and Water Heating: Technical and Achievable Technical Potential (MW in 2029)

Sector	Summer		
	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2029 Sector Peak
Residential	232	8	<1%
Commercial	- - -	- - -	- - -
Industrial	- - -	- - -	- - -
Total	232	8	<1%

Detailed assumptions providing values and sources that derived potential and levelized costs are shown in Table 34.

Table 34. Assumptions for Residential DLC Air-conditioning and Water Heating Potential

Program Concept	Assumptions
Customer Sectors Eligible	All Residential
End Uses Eligible for Program	Central AC (or Heat Pump) and Electric Water Heater
Customer Size Requirements, if any	N/A
Summer Load Basis	Top 20 Summer Hours
Winter Load Basis	N/A

Inputs	Model Values	Model Assumptions
Annual Attrition (%)	7%	Studies have found 7% (composed of 5% change of service and 2% removals) from utilities, including RMP, Xcel, Eon US, SMUD, FP&L (removals range from 1%–3%).
Per Customer Impacts (kW)	0.7 Central AC 0.2 Water Heating	Central AC – Adjustment based on central AC savings from other utilities (PacifiCorp [0.8] and Alliant [0.85]). Water Heating – Reduction level for Alliant program.
Total kW reduction per program	N/A	PSE does not currently offer this program.
Annual Administrative Costs (% of First-year Cost)	$60,000	An administrative adder of 15% was typically assumed for all residential program strategies (assuming that since 15% will be taken from a first cost of $400,000, the annual administrative cost will be $60,000).
Technology Cost	$150	$150 is indicated in the CEC report from 2004 (for the installed cost of ratio frequency load control devices). WH controls will require another switch and result in doubling this cost.
Marketing Cost	Central AC $30 Water Heating $0	Marketing costs are set at $30 based on data available from other utilities. No additional marketing costs for water heaters.
Incentive (annual costs)	Central AC $32 Water Heating $8	Incentives range from $30 to $35 for most utilities for one piece of equipment DLC program and $8 for additional equipment.
Communication Costs (per Customer Per Year)	$7	This value accounts for annual per-customer communication of a two-way transmission system.
Overhead: First Costs	$0	Charge occurs for set up of DLC Space and Water Heating.
Per Customer First Cost	Central AC $180 Water Heating $150	Sum of technology cost plus marketing cost.
Per Customer Ongoing	Central AC $62 Water Heating $31	For Central AC, ongoing costs are calculated from summing annual customer incentives, annual communication costs, and 15% of Technology costs for repair and/or replacement of equipment.
Eligible Load (%)	100% of the Cooling Load	Eligible load is the percentage of customers eligible for this program.
Technical Potential (as % of Gross)	Central AC 50% Water Heating 100%	The central AC program is modeled as a 50% cycling program. Due to the tank, water heating can be shut off for the entire event (100% reduction).
Program Participation (%)	Central AC 35% Water Heating 2%	Of customers with central AC, the assumption is 35% of these customers will participate. All customers with electric space heating will also include water heating in the program.
Event Participation (%)	90%	It is assumed each customer will be allowed to miss one event a year.

Large Commercial DLC

Direct control of commercial customers is an enticing option for utilities due to the large size of loads and the reliability of direct control. Yet, this option requires significant technological investment in coordination with existing EMS, and it is generally not favored by customers. Utilities offering programs to large nonresidential customers include: Florida Power and Light, Xcel Energy, Otter Tail Power and Light, Madison Gas and Electric, Wisconsin Electric, and Wisconsin Public Service. PSE has recently started a pilot large commercial DLC program with has one participating customer.

Although the program history is limited, this study estimates potential for large commercial customers, requiring a size threshold of 500 kW to increase likelihood of EMS systems already existing in the customer facility. The following end uses are assessed by customer segment: cooling, hot water, lighting, plug loads, space heating, and refrigeration. It is assumed this program option would be called at similar frequency to the residential DLC program: approximately 20 hours per winter and 20 hours per summer.

Technically, only a small portion of the total end-use loads could be curtailed. To estimate the achievable technical potential, the most uncertain factor is program participation. Findings from the IEA survey indicated nonresidential DLC program participation rates are generally quite low (less than 1% of load), excepting Xcel Energy and Otter Tail Power, which achieved participation rates greater than 10% at a cost of about $250/kW. This study assumes a program participation rate of 15%. Event participation is assumed at 90% based on other national programs. As shown in Table 35, although approximately 83 MW and 53 MW at $126/kW and $95/kW are technically available for the winter and summer seasons, respectively, there is essentially no achievable technical potential for this program option due to a lack of interest among customers.

Table 35. DLC Large Commercial: Technical and Achievable Technical Potential (MW in 2029)

Sector	Winter			Summer		
	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2029 Sector Peak	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2029 Sector Peak
Residential	24	3	<1%	23	3	<1%
Commercial	- - -	- - -	- - -	- - -	- - -	- - -
Industrial	- - -	- - -	- - -	- - -	- - -	- - -
Total	24	3	<1%	23	3	<1%

In terms of costs, the analysis estimates interfacing with existing EMS controls for each end use, reflecting a hierarchy of measures: (1) cooling; (2) lighting; (3) hot water; (4) process; and (5) plug loads. Controls are assumed to last 10 years. Customer incentives are assumed at $6/kW per month ($72/kW-year), based on the need to pay customers relatively high incentives to have direct control over loads.

Detailed assumptions providing values and sources that derived potential and levelized costs are shown in Table 36.

Table 36. Assumptions for DLC Large Commercial Potential

Program Concept	Assumptions
Customer Sectors Eligible	All Commercial subsectors
End Uses Eligible for Program	Cooling, hot water, lighting, plug load, refrigeration
Customer Size Requirements, if any	Loads greater than $500 kW due to EMS system requirements
Summer Load Basis	Top 20 Summer
Winter Load Basis	Top 20 Winter

Inputs	Model Values	Model Assumptions
Annual Attrition (%)	2%	Based on rate of electric turnover.
Per Customer Impacts (kW)	Varies by Sector	This value is a product of technical potential and average kW of eligible customers.
Total kW reduction per program	N/A	PSE does not currently offer this program.
Annual Administrative Costs	$50,000	Due to smaller number of customers, annual administration costs reduced from $60,000 to $50,000 for the commercial and industrial sector.
Technology Cost	Varies by Sector	Cost estimates assume the sites have centralized EMS systems and are based on costs for participants in PG&E's Auto Critical Peak Pricing Program. These costs reflect a hierarchy of DR measures that goes: (1) Cooling; (2) Lighting; (3) Hot Water; (4) Process; and (5) Plug load. DLC projects require a costly interface with existing EMS controls. It is assumed these controls will be linked to facilitate cooling DR measures initially with additional measures, most often lighting, added on once the system is connected (i.e., lighting measures cannot be implemented at the lower cost without first incurring the costs associated with cooling measures).
Marketing Cost (per new participant)	$500	$500 per customer for marketing (based upon 10 hours of effort by program staff at $50/hr).
Incentive (annual cost per participant)	$72/kW annually	We have observed $6/kW per month based upon other studies. We arrive at $72/kW annually through multiplying the $6/kW assumption by 12 months.
Communication Costs (per Customer Per Year)	N/A	
Overhead: First Costs	$200,000	We assume $200,000 overhead as a standard program development assumption for commercial programs, which includes costs for internal labor, research, and IT/billing system changes ($100,000 for labor and $100,000 for IT). This cost is only included in the winter portion.
Per Customer First Cost	Varies by Sector	Our cost estimate assumes each site has a centralized EMS system and is based on costs for participants in PG&E's Auto Critical Peak Pricing Program. These costs reflect a hierarchy of DR measures that goes: (1) Cooling; (2) Lighting; (3) Hot Water; (4) Process; and (5) Plug load. DLC projects require a costly interface with existing EMS controls. It is assumed these controls will be linked to facilitate Cooling DR measures initially with additional measures, most often lighting, added on once the system is connected (i.e., lighting measures cannot be implemented at the lower cost without first incurring the costs associated with cooling measures).

Per Customer Ongoing	Varies	Ongoing costs are calculated from summing annual customer incentives and 5% of technology costs for repair and/or replacement of equipment.
Eligible Load (%)	Varies by Sector	We assume full eligibility of loads greater than 200 kW.
Technical Potential (as % of Load Basis)	Varies by Sector	These assumptions are based on detailed engineering audits of DR potential of nonresidential customers throughout California, with third-party verification of results. Findings are amalgamated by sector and end-use category and supported by senior engineering analysis.
Program Participation (%)	15%	Survey results indicate zero achievable potential when combined with other programs (10% is the high stand-alone potential). We assume participation is more likely 15% (a range of participation levels are observed nationally (0.1% to 30.5% - Xcel, Otter Tail Power).
Event Participation (%)	90%	This assumption is based on Xcel Energy Peak Controlled Rates and is consistent with similar programs.

Interruptible Loads

Interruptible programs refer to contractual arrangements between the utility and its customers, typically nonresidential customers who agree to curtail or interrupt their operations, in whole or part, for a predetermined period when requested by the utility. In most cases, mandatory participation or liquidated damage agreements are required once the customer enrolls in the program; however, the number of curtailment requests, both in total and on a daily basis, is limited by the terms of the contracts.

Customers are generally not paid for individual events, but they are compensated in the form of a fixed monthly amount (per kW) of pledged interruptible load or through a rate discount. Typically, contracts require customers to curtail their connected load by a set percentage (e.g., 15%–20%) or a predetermined level (e.g., 100 kW), whichever is greater. These programs often involve long-term contracts and have penalties for non-compliance, which range from simply dropping the customer from the program to more punitive actions, such as requiring the customer to repay the utility for the committed (but not curtailed) energy at market rates.

The IEA survey of 40 utilities' DR programs revealed slightly more than half of utilities surveyed offer curtailable or interruptible rate programs to their nonresidential customers. Utilities offering programs included almost all the major utilities in California, Illinois, Indiana, Iowa, Minnesota, and Wisconsin as well as a variety of other utilities, including Allegheny Energy, Colorado Springs Utilities, Hydro Quebec, and Kansas City Power and Light. Most utilities require minimum demand reductions for customers to be eligible for the programs, ranging from 50 kW for Xcel Energy, up to the more typical level of 250 kW for MidAmerican.

In this study, it is assumed nonresidential customers with a monthly demand of at least 500 kW would be eligible for such a program. Technical potential is estimated by customer segment. One key aspect to the potential savings associated with the interruptible program is backup generation. Since these participants can turn on a backup generator during these critical peak times, the burden on a customer with a backup generator is minimal. In many utility programs (excluding those in California), customers are allowed to use backup generators to meet curtailment requirements.

Table 37 shows 70 MW (winter) and 71 MW (summer) of technical potential for nonresidential customers and 14 MW (winter) and 15 MW (summer) of achievable technical potential, totaling <1% of PSE's 2029 peak load.

Table 37. Interruptible Program: Technical and Achievable Technical Potential (MW in 2029)

Sector	Winter			Summer		
	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2029 Sector Peak	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2029 Sector Peak
Residential	- - -	- - -	- - -	- - -	- - -	- - -
Commercial	47	10	<1%	48	10	<1%
Industrial	23	5	<1%	23	5	<1%
Total	70	14	<1%	71	15	<1%

Detailed assumptions providing values and sources that derived potential and levelized costs are shown in Table 38.

Table 38. Assumptions for Interruptible Nonresidential Potential

Program Name	Assumptions
Customer Sectors Eligible	Nonresidential (Large C/I)
End Uses Eligible for Program	N/A
Customer Size Requirements, if any	Customers >200kW
Summer Load Basis	Top 40 Summer Hours
Winter Load Basis	Top 40 Winter Hours

Inputs	Model Value	Model Assumption
Annual Attrition (%)	2%	Based on rate of electric turnover.
Per Customer Impacts (kW)	Varies by Sector	This value is a product of technical potential and average kW of eligible customers.
Total kW reduction per program	N/A	
Annual Administrative Costs	$50,000	Due to the smaller number of customers, annual administration costs reduced from $60,000 to $50,000 for the commercial and industrial sector.
Technology Cost	$150	Cost to convert AMR to AMI meter.
Marketing Cost	$500	Reports indicate $500 per customer for marketing (based on 10 hours of effort by program staff at $50/hr).
Incentive	$48/kW	Cost estimated as an average of values of several utilities.
Communication Costs (per Customer Per Year)	N/A	

Overhead: First Costs	$200,000	We assume $200,000 overhead as a standard program development assumption for commercial programs, which includes costs for internal labor, research, and IT/billing system changes ($100,000 for labor and $100,000 for IT). This cost is only included in the winter portion.
Per Customer First Cost	$650	Sum of technology costs and marketing cost.
Per Customer Ongoing	$430	Sum of Repair (technology cost times (1/20)), ongoing customer contractors ($400), communication charge ($7), and data collection charge ($15).
Per KW Ongoing	$48	Incentive.
Eligible Load (%)	Varies by Sector	We assume full eligibility of loads greater than 500 kW.
Technical Potential (as % of Gross)	25% commercial	These assumptions are based on detailed engineering audits of DR potential of nonresidential customers throughout California, with third-party verification of results.
Program Participation (%)	25%	These assumptions are based on information available from the utilities.
Event Participation (%)	90%	Assumed one summer and one winter event can be opted out of.

Demand Buyback

Under demand buyback (DBB) or demand bidding arrangements, the utility offers payments to customers for reducing demand when requested by the utility. Under these programs, customers remain on a standard rate, but they are presented with options to bid or propose load reductions in response to utility requests. The buyback amount generally depends on market prices published by the utility ahead of the curtailment event, and the reduction level is verified against an agreed-upon baseline usage level.

DBB is a mechanism enabling consumers to actively participate in electricity trading by offering to undertake changes in their normal consumption patterns. Participation requires the flexibility to make changes to their normal electricity demand profile, install the necessary control and monitoring technology to execute the bids, and demonstrate bid delivery. One of several Internet-based programs is generally used to disseminate information on buyback rates to potential customers, who can then take the appropriate actions to manage their peak loads during requested events. The program option in this analysis targets large, nonresidential customers (>200kW), consistent with national programs.

Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for energy reduced during each event, based primarily on the difference between market prices and utility rates. DBB products are common in the United States and are being offered by many major utilities. Using DBB offerings to mitigate price volatility in power markets is especially common among independent system operators (ISOs), including ISOs in California (CAISO), New York (NYISO), and New England

(ISO-NE). However, DBB options currently are not being exercised regularly due to relatively low power prices. The IEA survey of 40 utilities' DR programs revealed about half of the utilities surveyed offered DBB programs to their nonresidential customers. Investor-owned utilities offering programs include almost all of the major utilities in California, Illinois, Indiana, Minnesota, and Wisconsin as well as a variety of other utilities, including Allegheny Energy, KCP&L, and Portland General Electric.

Six utilities were interviewed that reported larger DBB program impacts as part of the previous IEA survey. Utilities generally restrict eligibility for DBB programs to large customers who can reduce their loads by at least 500 kW–1,000 kW during peak periods. Of the six utilities interviewed, only Commonwealth Edison has a low minimum load reduction criterion of 10 kW. Program participation has also been significantly influenced by the minimum load reduction required; Commonwealth Edison consequently has 3,700 participants.

Some utilities, however, have captured significant demand reduction potential from just a few program participants. Minnesota Power estimates it could realize about 100 MW of demand reduction—about 9% of its nonresidential peak demand—from its five participants in this program if spot market prices again reach the heights of 1999–2000. Commonwealth Edison claims the second largest peak reduction potential of the utilities interviewed, at about 5% of its nonresidential peak demand. The other utilities estimated their potential peak demand reduction impacts from this program at 0%–2% of nonresidential peak demands. These programs have not resulted in large peak demand impacts for utilities in the past five years due to the relatively low level of spot market prices during this period.

Table 39 shows that in the winter season, of more than 84 MW of technical potential, an average of 1 MW can be expected during any one event. In the summer season, 85 MW technical potential results in an average of 1 MW expected during any one event.

Table 39. Demand Buyback: Technical and Achievable Technical Potential (MW in 2029)

Sector	Winter			Summer		
	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2029 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2029 Peak
Residential	- - -	- - -	- - -	- - -	- - -	- - -
Commercial	64	1	<1%	65	1	<1%
Industrial	20	<1	<1%	20	<1	<1%
Total	84	1	<1%	85	1	<1%

Because participants are paid based on market energy rates, this program's cost is relatively low, at levelized costs of $83/kW-year and $11/kW-year in the winter and summer seasons, respectively. New customer costs include hardware ($150 for any necessary metering), marketing ($500), and program development ($200,000, winter only). New participant costs must be reinvested due to a 2% annual attrition rates and a hardware life of 20 years.

Detailed assumptions providing values and sources that derived the potential and levelized costs are shown in Table 40.

Table 40. Assumptions for DBB Potential

Program Name	Assumptions
Customer Sectors Eligible	All Non-Residential Market Segments
End Uses Eligible for Program	Total Load of All End Uses
Customer Size Requirements, if any	Customers >200kW
Summer Load Basis	Top 20 Summer Hours
Winter Load Basis	Top 20 Winter Hours

Inputs	Model Value	Model Assumptions
Annual Attrition (%)	2%	Based on the rate of electric turnover.
Per Customer Impacts (kW)	Varies by Sector	This value is a product of technical potential and the average kW of eligible customers.
Total kW reduction per program	N/A	PSE does not currently offer this program.
Annual Administrative Costs	$50,000	Due to smaller number of customers, annual administration costs reduced from $60,000 to $50,000 for the commercial and industrial sector.
Technology Cost	$150	Cost to convert AMR to AMI meter.
Marketing Cost	$500	Reports indicate $500 per customer for marketing (based upon 10 hours of effort by program staff at $50/hr).
Incentive	$10/kW	We assume an estimate of $10 per kW, which is taken from 2000–2002 Demand Exchange Program, based on average market prices of $100/MWh.
Communication Costs (per Customer Per Year)	N/A	
Overhead: First Costs	$200,000	We assume $200,000 overhead as a standard program development assumption for commercial programs, which includes costs for internal labor, research, and IT/billing system changes ($100,000 for labor and $100,000 for IT). This cost is only included in the winter portion.
Per Customer First Cost	$650	Sum of technology costs and marketing costs.
Per Customer Ongoing	$10/kW + $15	Ongoing costs are calculated from summing annual customer incentives and 5% of technology costs for repair and/or replacement of equipment.
Eligible Load (%)	Varies by Sector	We assume full eligibility of loads greater than 200 kW.
Technical Potential (as % of Gross)	20%	These assumptions are based on detailed engineering audits of DR potential of nonresidential customers throughout California, with third-party verification of results.
Program Participation (%)	Varies by Sector	This assumption is based on internal survey results, with an average of 20% participation.
Event Participation (%)	19%	Event participation is based on 2006 PacifiCorp results of 19% event participation (based on an average price of $130/MWh at 12 MW per event).

Critical Peak Pricing

Under a CPP program, customers receive a discount on their normal retail rates during off-peak periods in exchange for paying premium prices during critical peak events. However, the peak price is determined in advance, providing customers with some degree of certainty about participation costs. The basic rate structure is a TOU tariff where the rate has fixed prices for usage during different blocks of time (typically on- and off-peak prices by season, occasionally including a mid-peak price). During CPP events, the normal peak price under the TOU rate structure is replaced with a much higher one to reflect the utility's power cost during peak periods.

CPP rates only take effect a limited number of times during the year, with a cap typically set on the number of CPP event hours that can be implemented. In times of emergency or high market prices, the utility can invoke a critical peak event, where customers are notified and rates become much higher than normal, encouraging customers to reduce or shift loads. Most CPP programs provide advance notice along with event criteria, such as a threshold for forecasted weather temperatures, to help customers plan their operations. One of the attractive features of the CPP program is the absence of a mandatory curtailment requirement; however, both incentives and penalties lie within the pricing structure.

The benefit of a CPP rate over a standard TOU rate is an extreme price signal can be sent to customers for a limited number of events. Utilities have found demand reductions during these events are typically greater than those during TOU peak periods. This occurs for several reasons:

1. Customers under CPP rates are often equipped with automated controls triggered by a signal from the utility.

2. The higher CPP rate serves as an incentive for customers to shift load away from the CPP event period.

3. The relative rarity of CPP events may encourage short-term behavioral changes, resulting in reduced consumption during the events.

Since the CPP rate only applies on select days, it raises a number of questions about when a utility can call an event, for how long, and how often. The rules governing utility dispatch of CPP events varies widely by utility and by program, with some utilities reserving the right to call an event any time, and others providing notice one day prior to the event.

Currently, peak pricing is being offered through experimental pilots or full-scale programs by several organizations in the United States, notably Southern Company (Georgia Power), Gulf Power, Niagara Mohawk, California utilities (SCE, PG&E, SDG&E), PJM Interconnection, and New York ISO (NYISO). Adoption of CPP has not been as widespread in western states as it has been in eastern states.

Residential CPP. The most common national CPP programs are offered to the residential customer class. Recently, significant literature has shown the value of a technology-enabled CPP program, which essentially provides customers with smart thermostats. These can be programmed to change temperature settings and even control other end uses, such as lighting and water heating, depending on the pricing period (e.g., critical peak period, on-peak, or off-peak). This combination of pricing and technology has shown to be an effective combination in improving per-customer load impacts.

More recently, process-oriented appliances, such as dishwashers and washing machines, have incorporated technologies to respond to external CPP signals. During critical events when a rate increase occurs, these "energy-managed appliances" receive notification on the appliance interface, giving customers direct notification and the option of delaying use of the appliance. These appliances also have the capability to temporarily reduce their energy consumption during moments of grid instability. For example, a clothes dryer with this technology will reduce power upon receipt of a remote signal from the utility, then correct for the momentary reduction through extending the drying time. In both situations of signal response, the customer has the ability to override the signaled reduction.

Technically, national studies have shown that 13%–40%[7] of peak demand can be reduced for participating customers; this study assumes a 27% reduction based on the California pricing pilot.[8] In 2006, Gulf Power's CPP program had 2.5% of customers and a goal of reaching 10% penetration. Event participation is estimated to be 90%, based on opt-outs being typically less than 5% now that utilities require customers to use the Internet or the call center to opt out of a CPP event.

Table 41 shows that 762 MW and 44 MW are technically available for the winter and summer periods, respectively. These figures are reduced by the program and event participation rates, resulting in 69 MW (winter) and 40 MW (summer) of achievable technical potential.

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[7] Charles River Associates (CRA), Impact Evaluation of the California Statewide Pricing Pilot, March 16, 2005. California Energy Commission (CEC), Statewide Pricing Pilot load reduction data for Zone 4 (desert and inland climate), provided in MS Excel by Pat McAuliffe, CEC staff, via e-mail November 3, 2006. Demand Response Research Center (DRRC), Ameren Critical Peak Pricing Pilot, Presentation by Rick Voytas, Manager of Corporate Analysis at Ameren Services, at the Demand Response Town Hall Meeting, Berkeley, CA, June 26, 2006. International Energy Agency, Demand-Side Management Programme, Task XI: Time of Use Pricing and Energy Use for Demand Management Delivery, Subtask 2: Time of Use Pricing for Demand Management Delivery, April 2005. Rocky Mountain Institute, Automated Demand Response System Pilot, Final Report Volume 1: Introduction and Executive Summary, March 2006. Summit Blue Consulting, Interim Report for the myPower Pricing Segment Evaluation, prepared for PSEG, December 27, 2006. University of California Energy Institute (UCEI), Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, S. Borenstein et al., October 2002.

[8] See Charles River Associates, 2005.

Table 41. Residential CPP : Technical and Achievable Technical Potential (MW in 2029)

Sector	Winter Technical Potential	Winter Achievable Technical Potential	Winter Achievable Technical Potential as % of 2029 Sector Peak	Summer Technical Potential	Summer Achievable Technical Potential	Summer Achievable Technical Potential as % of 2029 Sector Peak
Residential	762	69	2%	444	40	2%
Commercial	---	---	---	---	---	---
Industrial	---	---	---	---	---	---
Total	762	69	<1%	444	40	<1%

The levelized cost of this program is $83/kW and $138/kW for winter and summer, respectively. Detailed assumptions providing values and sources that derived the potential and levelized costs are shown in Table 42.

Table 42. Assumptions for Residential CPP Potential

Program Name	Assumptions
Customer Sectors Eligible	All Residential Market Segments
End Uses Eligible for Program	Total Load of All End Uses
Customer Size Requirements, if any	All
Summer Load Basis	Top 20 Summer Hours

Inputs	Model Value	Model Assumptions
Annual Attrition (%)	7%	Studies have found 7% (composed of 5% change of service and 2% removals) from utilities, including RMP, Xcel, Eon US, SMUD, FP&L (removals range from 1%–3%).
Per Customer Impacts (kW)	Varies by sector	This value is a product of technical potential and average kW of eligible customers.
Total kW reduction per program	N/A	PSE does not currently offer this program
Annual Administrative Costs	$60,000	An administrative adder of 15% was typically assumed for all residential program strategies (assuming that since 15% will be taken from a first cost of $400,000, the annual administrative cost will be $60,000).
Technology Cost	$150	$150 is indicated in the CEC report from 2004 (for the installed cost of ratio frequency load control devices). WH controls will require another switch and result in doubling this cost.
Marketing Cost	$35	This cost assumes an increase from the TOU marketing cost.
Incentive (annual costs)	N/A	
Communication Costs (per Customer Per Year)	$7	This value accounts for annual per-customer communication of a one-way transmission system.
Overhead: First Costs	$400,000	$200k for labor and $200k for IT.
Per Customer First Cost	$185	This value is calculated from the technology cost and the marketing cost per new participant.
Per Customer Ongoing	$34	Ongoing costs are calculated from summing annual customer incentives and 7% (1/15) of technology costs for repair and/or replacement of equipment.
Eligible Load (%)	100%	All residential customers are eligible.

Technical Potential (as % of Gross)	27%	The assumption is based on results from California residential pilot CPP programs for statewide average (Charles River Associates, 2005).
Program Participation (%)	10%	Gulf Power has the only full-scale residential CPP program. The company reported 8,500 participants as of October 2006, out of 350,000 residential customers (2.4%). (Sources: Jim Thompson presentation to PURC Energy Policy Roundtable, October 31, 2006; and FERC Form 861 data, 2005.) They expect to reach at least 10% penetration. (Source: Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, Severin Borenstein, Michael Jaske, and Arthur Rosenfeld, October 2002.)
Event Participation (%)	90%	Opt-outs are typically less than 5% now that utilities are requiring customers to use the Internet or call center to opt out of a CPP event. (Source: Conversation with Tom Van Denover, VP Comverge March 2007.) With 2-way communications (through AMI or ZigBee gateway, for example) utilities can identify and replace malfunctioning thermostats, so event participation is much higher than in older one-way, switch-based DLC programs.

5. Distributed Generation Potentials

Scope of Analysis

In addition to traditional energy-efficiency technologies, this report includes an analysis of distributed generation (DG) resources. These resources are used to produce electricity and offset utility electric loads. They are divided into two broad categories: non-renewable and renewable resources. Non-renewable resources include on-site generation using a combined heat and power (CHP) unit that consumes natural gas. Renewable resources include energy-based resources of biomass and three "clean generation" (non-combustion) resources: building photovoltaics (on-site solar), small hydro, and small wind. This study only considers on-site generation primarily used for a building's energy and heat needs. Large "central-station" generation facilities that operate to sell the majority (or all) of their power to the grid are outside the scope of this work.

The analysis specifically examined five DG resources:

- *Non-renewable CHP* includes all generators that produce energy by burning a fossil fuel, such as natural gas or diesel. In this study, only natural gas is considered because it is readily available and environmentally cleaner-burning than diesel. This category includes CHP used in cooling applications, sometimes referred to as CCHP (combined cooling heating and power), where the generator unit is coupled with an absorption chiller.
- *Renewable CHP* refers to energy generated from any plant- or animal-based (biomass) material. Biomass can be directly combusted (i.e., industrial biomass) or fed into an anaerobic digester to produce biogas, which can then be combusted to produce electricity. Although biomass energy is based on a renewable resource, this combustion process is not considered "clean" as it does produce emission products (e.g., carbon dioxide, NOx, etc.).
- *Building Photovoltaics* are rooftop-based photovoltaic (PV) panels that convert sunlight to electricity.
- *Small Hydro* is sometimes known as run-of-river hydroelectric power generation, as dams need not be built to regulate water flow. Four basic types of hydro installations are included in this study: small, micro, low-power conventional, and low-power unconventional.
- *Small Wind* encompasses small, electricity-generating wind turbines installed at a customer's site.

Methodology

The overall methodology used to calculate the potential from distributed generation resources includes three key steps:

- ***Technical potential*** was calculated separately for each resource categories, using the following key data inputs:

- Non-renewable CHP: PSE's non-residential customer database for "typical" building energy loads used to determine feasibility by market segment.

- Renewable CHP: PSE's industrial customer database for size and count of biomass-producing industrial facilities and service territory demographics for biogas-producing (anaerobic digester) facilities.

- Building PV: PSE customer counts and building square footage assumptions.

- Small Hydro: potential river sites for turbines from Idaho National Laboratory's Virtual Hydropower Prospector (VHP)[9] by county and installation type, and USGS stream flow data from representative streams to determine capacity factors.

- Small Wind: energy output estimated using power curves for sample turbines and available TMY2 wind data,[10] in addition, population density, proximity to airports, and sensitive land areas are considered.

• ***Various technology costs*** were calculated based on literature searches, available databases, and other states' programs. Installed costs included capital costs, planning, installation, and other adders.

• ***Achievable technical potential*** was determined for each resource class based on other programmatic successes, including within PSE's territory. Note that not all achievable technical potential will be cost-effective.

Summary of Findings

This section presents a summary of the key findings for distributed generation potentials. More detail regarding each resource follows these highlights.

Resource Potential

To accurately estimate the quantity of market potential, it is essential to know the current penetration of DG technologies currently found in the marketplace. The installed nameplate capacity, presented in Table 43, was obtained from existing databases,[11,12,13] and PSE data. This capacity excluded large "central-station" generation facilities and large, utility-owned generation facilities (e.g., wind farms, CHP facilities greater than 30 MW).

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9 http://hydropower.id.doe.gov/prospector/index.shtml

10 TMY2 or Typical Meteorological Year, includes wind speed data compiled by the National Renewable Energy Laboratory for cities across the country.

11 http://www.eea-inc.com/chpdata/index.html

12 http://www.epa.gov/lmop/proj/index.htm gives waste-in-place data for eligible landfills. If waste-in-place is not specified, a 500 kW generation potential is assumed.

13 http://www.small-hydro.com/index.cfm?fuseaction=countries.sites&country_ID=82

Table 43. Installed DG Capacity by Resource (2008)

Resource	Capacity (MW)
Non-Renewable CHP	40
Renewable CHP	52
Building Photovoltaics	0.9
Small Hydro	0.01
Small Wind	0.02
Total	93

Technical Potential

The total technical potential from DG resources, excluding existing capacity, is 3,493 aMW in 2029 (Table 44). More than half of the technical potential for DG comes from PV (51%), followed by non-renewable CHP (28%), small hydro (14%), renewable CHP (5%), and small wind (2%). It should be recognized that technical potential for the DG resources is significantly higher than what can be achieved, primarily due to high upfront costs required for these resources and feasibility constraints, particularly for small wind and hydro.

Table 44. Technical Potential for DG Renewable Resources (2029)

Resource	aMW	Percent
Non-Renewable CHP	1,039	28%
Renewable CHP	211	5%
Building Photovoltaics	1,912	51%
Small Hydro	265	14%
Small Wind	66	2%
Total	3,493	100%

Achievable Technical Potential

For DG resources, achievable technical potential represents the portion of technical potential that might actually be installed. It should be realized that not all these resources are cost-effective, but, nonetheless, may be installed by customers willing to accept long payback times.

Note that the achievable technical potential also considers current incentives for these resources. Currently, customers can receive the Washington Renewable Energy Production Incentive[14] for anaerobic digesters, wind, and PV. In addition, the Federal Production Tax Credit[15] is currently

14 Currently available through 6/30/2014, the incentive offers $0.12 – $0.54/kWh, depending on technology and where equipment was manufactured, with a maximum incentive of $2,000/year.

15 Production Tax Credit is 1.9 cents/kWh available through December 31, 2008, and applies to the first 10 years of production (http://www.dsireusa.org).

available to commercial and industrial projects, and the Federal Renewable Energy Production Incentive[16] is available to non-taxable entities (e.g., municipal projects) for clean energy options.

The achievable technical potential for all DG resources is shown in Table 45. Compared to the technical potential of DG resources (Table 45), this potential is significantly less due to economic considerations, low awareness of technologies, and other permitting or interconnection concerns (details are provided in the results sections, below).

Among the DG resources, non-renewable CHP composes the largest percentage of achievable technical potential (34 aMW), followed by photovoltaics (21 aMW), renewable CHP (8.7 aMW), small hydro (0.12 aMW) and small wind (0.04 aMW).

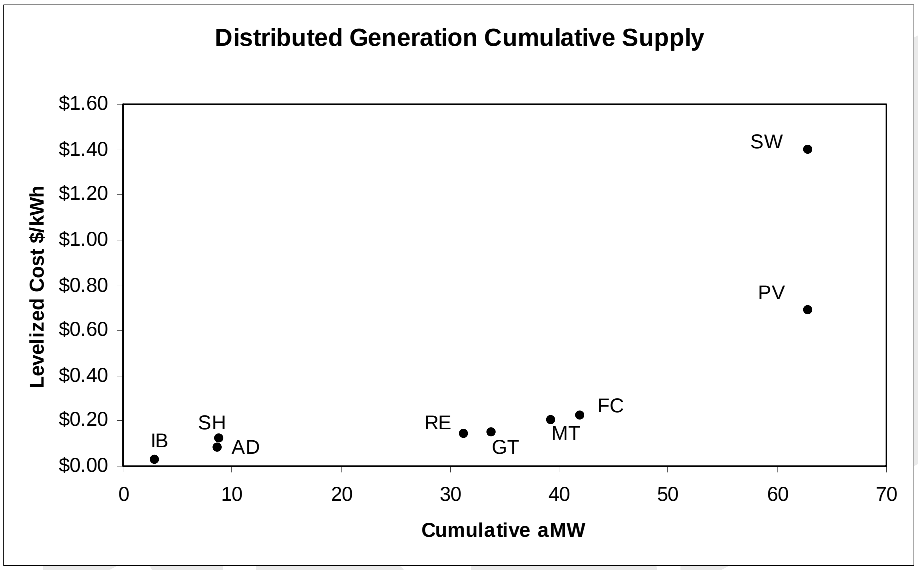
Table 45. Achievable Technical Potential for DG Resources (2029)

Resource	aMW	Percent
Non-Renewable CHP	34.0	53%
Renewable CHP	8.7	14%
Building Photovoltaics	21.0	33%
Small Hydro	0.12	0%
Small Wind	0.04	0%
Total	66.4	100%

Figure 27 presents the cumulative supply curve for all DG resources. Biomass Energy is split into Industrial Biomass (direct combustion) and Anaerobic Digesters (biogas combustion). Non-renewable CHP is divided into each generation technology. Further details on these and all renewable potentials are discussed below.

16 Renewable Energy Production Incentive is 1.5 cents per kWh (indexed for inflation) with a 10-year term. (http://www.dsireusa.org).

Figure 27. Cumulative Supply Curve for Dispersed Generation Renewable Resources (2029)



RE: reciprocating engine, MT: Microturbine, FC: Fuel Cell, GT: Gas turbine, IB: Industrial Biomass, AD: Anaerobic digester, PV: Building photovoltaics, SH: Small hydro, SW: Small wind.

Combined Heat and Power

CHP encompasses all technologies that generate electricity while heating and/or cooling a customer's facility. Generally, the power generated through these technologies is expected to contribute to the utility's base load resources, rather than to peak load requirements. Peak load reduction with an on-site generator or dispatchable standby generation is treated as part of the Demand Response potential (Section 4). CHP has traditionally been installed in hospitals, schools, and manufacturing facilities, but it can be used across nearly all facilities that have a fairly coincident electric and thermal load and an average annual energy load greater than about 30 kW. CHP used to offset cooling loads is most applicable for building segments with large cooling requirements, such as retail, grocery, and hotel/motel. CHP is broadly divided into non-renewable and renewable subcategories based on the fuel used.

CHP includes a standard electrical generator, but total energy needs of the business are also reduced by capturing the generator's waste heat and using it for other processes. For example, a typical spark-ignition engine has an electrical efficiency of only about 35%. The "lost" energy is primarily waste heat. A CHP unit will capture much of this waste heat and use it for space heating, water heating, or to power an absorption chiller, achieving an overall efficiency of up to 80%. Thus, savings become available by offsetting boiler or air conditioning usage in addition to electricity being generated.

The three primary generator technologies available in the market are: 1) reciprocating engines (either spark-ignition or compression-ignition); 2) turbines (gas or steam for larger capacity

[>1 MW] or microturbines for smaller capacity [<1 MW]); and 3) fuel cells, primarily those using phosphoric acid (PAFC) or molten carbonate (MCFC) as the electrolyte, although other types of fuel cells are now becoming commercially viable.[17]

As described earlier, CHP is divided into two broad categories, depending on the fuel source-renewable or non-renewable. The same generators described above can be used with either fuel type. Note that biomass fuels from the agricultural sector (e.g., crop waste such as bagasse—from sugar, rice hulls, or rice straw) are not considered in this study. Due to high moisture content and varying ability, crop residues are not a viable fuel alternative for most CHP applications.[18] In addition, the prime energy producing crops (sugar cane and rice) are largely not present in PSE territory.

Background information on costs, operating parameters, measure life, etc., for each technology are given in Volume II, Appendix F.

CHP Technical Potential

The technical potential for CHP assumes all technologies will be adopted in all available customer sites to meet their average annual electric demand, regardless of cost or other market barriers. This applies to all non-residential building types, large industrial biomass-producing facilities, and sites that may use anaerobic digesters. These three sectors, however, need to be treated separately. To derive this potential, PSE's 2007 customer database was used; as such, the technical potential given is ramped up from the first-year load. Details on the resources used are given in Volume II, Appendix F. The technical potential by resource category is provided in Table 46.

Renewable: Anaerobic Digesters. Anaerobic digesters create methane gas (biogas fuel) by breaking down liquid or solid biological waste. The captured waste heat of the CHP unit is, in large part, used to maintain the high temperature required of the digesters themselves. The digesters are grouped into two bins: small and large. The small anaerobic digesters are coupled with smaller-scale generators, such as reciprocating engines, microturbines, or fuel cells, while large anaerobic digesters use generators such as steam or gas turbines with a capacity greater than 1,000 kW. The best candidates for anaerobic digesters include animal farms (dairy or swine), landfills, and wastewater treatment facilities.

For farms, the amount of biogas that can be generated is directly related to the number and type of animals on site. Based on typical collection systems, a study by the EPA assumes that one cow will generate 2.5 kWh/day and one pig will generate 0.25 kWh/day.[19] Given size constraints, it is likely only dairy farms with more than 500 head of cattle or 2,000 head of swine

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17 Note that not all types of fuel cells available operate at a high enough temperature to be applicable for CHP-configuration. Only viable types are considered here.

18 "Combined Heat & Power Market for Opportunity Fuels," Resource Dynamics Corp, 2004.

19 "Market Opportunities for Biogas Recovery," EPA-430-8-06-004, http://www.epa.gov/agstar

will install a generator. Based on the number and average size of farms across the state (by zip code) within PSE territory,[20,21] an overall potential is calculated.

Wastewater treatment facilities are similar to farms; the population served by a particular facility will determine the expected generation output. A study by the Federal Energy Management Program assumes 10,000 people will generate approximately 1 million gallons of waste per day (1 MGD). Each MGD of waste can produce about 35 kW of energy; as such, generally 3 MGD is the minimum waste flow before an anaerobic digester will be installed.[22] Thus, only population centers with 30,000 people or greater are considered for wastewater generation. Finally, for landfills, the U.S. EPA Landfill Methane Outreach Program (LMOP) encourages the implementation of generators at landfills. As part of this program, a database of participating and candidate landfills, based on waste-in-place and throughput, is available by state (with zip code resolution).[12]

Renewable: Industrial Biomass. Industrial biomass includes the waste product from industries that is combusted in place of natural gas or other fuel. For solid industrial biomass, the heat produced from combustion is often used to run a steam turbine.[23] The industrial biomass potential is based on customers with an average annual electric load greater than 1 aMW in the four key biomass-producing industries: lumber, food, pulp and paper, and chemical manufacturing. The PSE customer database is used to determine the overall load associated with these industries. For buildings with a load between 1 aMW and 5 aMW, an average load of 2.5 aMW is assumed; for those with a larger than 5 aMW annual load, the actual customer load was taken from PSE's nonresidential customer database. All industrial biomass facilities within this size range are considered CHP-eligible.

Non-Renewable Generation. For all other nonresidential facilities (excluding renewable-generation facilities), the only constraint on the technical potential is the applicability of a CHP unit within a particular building. For a building to be eligible for CHP, two key conditions need to be met: the ratio of thermal to electric loads should be within 0.5–2.5 (the range over which most CHP technologies operate), with a high coincidence between these two loads, and the overall loads should be fairly constant throughout the year. The overall percentage of buildings by market sector that are CHP-eligible, based on these ratio and load requirements, was obtained from Energy Insights™. Energy Insights has determined these consumption parameters from secondary sources, including the Energy Information Administration Commercial Buildings Energy Consumption Survey (CBECS), the Manufacturing Energy Consumption Survey (MECS) as well as market summaries developed by their own surveys, the Gas Technology Institute, and the American Gas Association. Using the PSE customer database, the number of CHP-eligible establishments within a load bundle, (e.g., 200 akW–499 akW or 500 akW–999 akW average annual electric load), together with an average load based on bundle size, is used to calculate the potential in aMW. For buildings with an annual load larger than 5 aMW, the

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20 http://www.nass.usda.gov/Census_of_Agriculture/index.asp

21 "Sizing and Characterizing the Market for Oregon Biopower Projects," CH2MHill for Energy Trust of Oregon, 2005.

22 http://www1.eere.energy.gov/femp/pdfs/bamf_wastewater.pdf

23 This is commonly referred to as *cogeneration*.

actual customer load is taken from the customer database. The cooling potential is based on building segments that have fairly constant cooling loads: Dry Good Retail, Grocery, Hospital, and Hotel/Motel.[24]

Table 46. CHP Technical Potential by Resource Category (aMW in 2029)

Technical Potential	Total
Small Anaerobic Digesters	120
Large Anaerobic Digesters	0
Industrial Biomass	90
Non-Renewable Heating	992
Non-Renewable Cooling	46
Total	1,249

Note: Results may not sum to total due to rounding

CHP Achievable Technical Potential

The first step in the analysis is an examination of what the market may accept, not all of which is necessarily cost-effective. The achievable technical potential is based on adoption rates within other programs (primarily SGIP in California). This analysis is fairly independent of the technical potential, but it provides reasonable results based on adoption rates through other programs.

Non-Renewable Generation. The achievable technical potential for non-renewable CHP is based on California's success of implementing CHP installations within SGIP. The results of SGIP were used as an expected generation outcome for PSE, normalized by the PSE load compared to the load of the participating SGIP utilities. The SGIP was in effect for six years and provides incentives that cover approximately 50% of the system cost. With slow initial growth for program implementation and greater expected barriers (e.g., longer payback periods, potentially less statewide support, insufficient interconnection standards, etc.), this generation is targeted for PSE after 10 years of program implementation. The four primary generator technologies (reciprocating engines, microturbines, fuel cells, and gas turbines) were all included in SGIP and treated distinctly in this analysis. It is assumed across all non-renewable CHP (except gas turbines) that 75% of the installations will go in the commercial sector, and 25% will be installed in the industrial sector. No residential sector penetration is assumed as residential CHP technologies are still nascent. Gas turbines, being generally quite large and generally better suited to the industrial sector, are assumed to penetrate 50% in each the commercial and industrial sector. The overall achievable technical potential in 2029 is 36 aMW for non-renewable CHP, 28 aMW of which for heating-based applications, and 8 aMW for cooling-based applications.

Renewable: Anaerobic Digesters. The availability of potential sites for anaerobic digesters (farms, landfills, wastewater treatment facilities) is area-specific; therefore, the adoption rate

[24] "Market Potential for Advanced Thermally Activated BCHP in Five National Account Sectors", Energy and Environmental Analysis, Inc., May 2003.

from other states' programs may not be representative for PSE territory. Instead, the potential was based on PSE's experience and a similar adoption percentage of technical potential as non-renewable CHP (3% in the first five years of program implementation and doubling within the next five years). All anaerobic digesters are installed in the commercial sector, and the achievable potential is about 6 aMW for smaller systems and effectively zero for larger systems in 2029.

Renewable: Industrial Biomass. Very few programs currently exist to promote industrial biomass adoption. Given the lack of data, the achievable technical potential is based on internal PSE knowledge, coupled with the adoption percentage of non-renewable resources. As the name indicates, all penetration is in the industrial sector and is about 3 aMW in 2029.

Resource Potential

The results of this analysis indicate a cumulative achievable technical potential of 45 aMW from all CHP technologies by 2029 (Table 47). As with all other resources, this potential is measured at the meter. The largest potential is from non-renewable reciprocating engine applications (24 aMW), followed by anaerobic digester (6.1 aMW).

Table 47. Achievable Technical Potential for CHP (aMW in 2029)

Sector	Industrial Biomass	Small Anaerobic Digesters	Large Anaerobic Digesters	Non-Renewable				Total
				Recip. Engine	Gas Turbine	Micro-turbine	Fuel Cell	
Industrial	3.0	0.0	0.0	5.6	1.3	0.7	0.5	11.1
Commercial	0.0	5.7	0.0	16.9	1.3	2.3	5.2	31.4
Total	3.0	5.7	0.0	22.4	2.5	2.9	5.8	42.5
% of 2029 System Sales	0.08%	0.16%	0.00%	0.63%	0.07%	0.08%	0.15%	1.13%
Levelized Cost ($/kWh)	$0.03	$0.08	$0.04	$0.13	$0.14	$0.19	$0.21	

Levelized costs ($/kWh) are shown in Table 47 for each technology, calculated using costs given in Volume II, Appendix F, along with the levelized fuel price and a nominal discount rate of 8.25%. Levelized costs for non-renewable CHP are based on heating-only applications. For cooling applications, costs average slightly higher.

Clean Energy

Clean energy consists of energy generation options that do not consume a hydrocarbon-based fuel; these are namely photovoltaics, small hydro, and small wind. Each resource is unique and, consequently, the technical and achievable technical potentials are calculated differently. Background information on costs, operating parameters, measure life, etc., for each technology are provided in Volume II, Appendix F.

Clean Energy Technical Potential

The technical potential for all clean energy resources is shown in Table 48. Below are details on the derivation of the technical potential for each of these technologies.

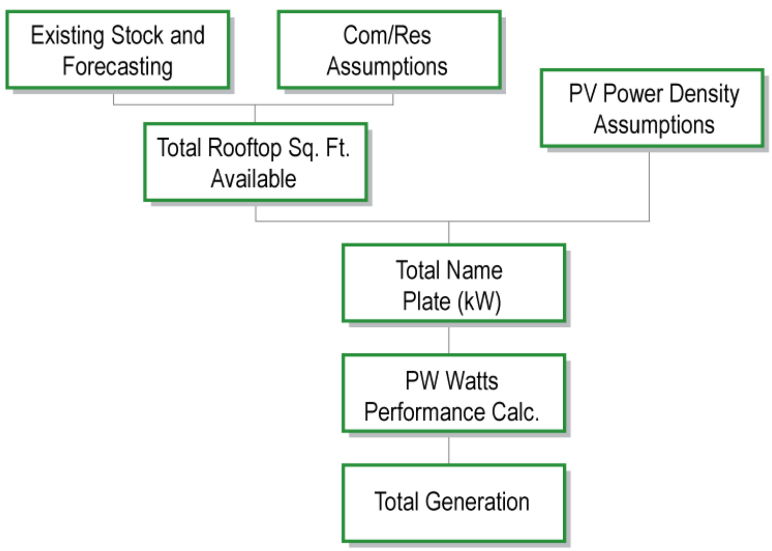
Table 48. Technical Potential of Clean Energy Resources by Technology (aMW in 2029)

Technology	Potential (aMW)
Building PV	1,912
Small Hydro	265
Small Wind	66
Total	2,243

Building PV

Analysis of this technical potential is based solely on rooftop applications. This provides a conservative estimate as other applications, such as ground or pole-mounted PV, awnings, and car ports, are not considered. This estimate of technical potential considers the physical limitations due to roof area, shading, orientation, and expected building growth. The PV methodology is diagrammatically displayed in Figure 28, showing how different inputs are used to estimate technical potential. Each input will be described in detail below, with further details available in Volume II, Appendix F.

Figure 28. Methodology for Calculating PV Potential



Existing Stock and Forecasting. Estimates of available square footage of roof area are based on site visits, surveys, and data mining results performed as part of this study for commercial and residential buildings in PSE territory. The load forecast is used to estimate the growth in building stock.

PV Commercial Assumptions. The following assumptions are comparable to and consistent with other studies:

- All commercial rooftops are considered flat (0° pitch).
- 35% of all roofs are unavailable (10% due to obstructions and equipment, 5% space lost due shading from equipment, and 15% from surrounding building shading and other technical restrictions).
- All building types are equally distributed across all zip codes.

PV Residential Assumptions. The following assumptions are based on field experience and remain consistent with other studies:

- Single-family and manufactured households typically have 4/12 (18.5o) pitch roofs.
- Multifamily structures have flat roofs (0o pitch).
- 83% of 4/12 pitch roof areas and 65% of flat roofs are unavailable due to shading and other obstructions.
- All building types are equally distributed across all zip codes.

PV Power Density Assumptions. PV cell technology evolves over time and efficiency continually improves. According to the DOE, cell efficiency is projected to improve at an average rate of roughly 2.1% a year across all three classes of technologies. This assumption is comparable with other studies. Conversely, there is also a performance degradation of 1% efficiency per year. Both of these assumptions are included in this analysis.

This analysis also takes into account market shares of competing solar cell technologies: mono-crystalline, poly-crystalline, and amorphous 'thin-film,' from which a weighted average is calculated to determine an overall efficiency. In addition, it is important to account for the space between modules needed for racking materials and installation requirements for the entire array, increasing the overall footprint. To adjust for this, the power density (W/sq.ft.) is reduced by 20% to give the total system array efficiency. This result is applied to the projected increase in cell efficiency to determine the annual power density.

The system power density multiplied by the useable square footage for each building type results in the total name plate capacity (kW) or the total DC kW installed.

PV Watts Performance Calculator. As noted earlier, the PV Watts performance calculator is used to determine the capacity factor.[25] The amount of solar insulation available is based on Seattle's weather station, which is equivalent to that used in the energy-efficiency building simulation models. The technical potential is based on the maximum roof area coverage of

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25 Developed by the National Renewable Energy Laboratory, the PV Watts Performance Calculator uses hourly Typical Meteorological Year (TMY) weather data and a PV performance model based on Sandia National Laboratories' PVFORM to estimate monthly and annual AC energy production (kWh).

commercial and residential building types, verses the achievable technical potential based on optimum system design. The resulting weighted average capacity factor of commercial and residential buildings for the technical potential is 0.10, while, for the achievable technical potential, it was calculated as 0.12.

Small Hydro

The technical potential for small hydro was calculated based on the sites listed in the Virtual Hydro Prospector (VHP). Data were downloaded for all suitable potential small hydro sites in PSE's territory. These data included capacity, county, and other information, such as head and stream flow. They were then analyzed to derive hydro potential by county, adding up the potential for all four installation types (i.e., small hydro, micro hydro, low-power conventional and low-power unconventional).

The potential hydro sites listed in the VHP were screened for feasibility based on the following criteria:

- Hydropower potential ≥10 kW.
- Not in a zone in which development was excluded by federal law or policy.
- Not in a zone making development highly unlikely because of land-use designations.
- Not coinciding with an existing hydroelectric plant.
- Located within 1 mile of a road.
- Located within 1 mile of part of the power infrastructure (power plant, power line, or substation) ***or*** within a typical distance from a populated area for plants of the same power class in the region.

After screening for feasibility criteria, the VHP calculates potential power output for each site using the following assumptions:

- ***Project location***: optimal, based on hydraulic head capture.
- ***Penstock length***: optimal, based on capturing 90% of hydraulic head with the longest, typical penstock length, and based on existing low-power or small hydro plants in the region.
- ***Flow rate***: lesser of either half the stream reach flow rate ***or*** no more than the flow rate required to produce 30 aMW of annual average energy.

Some of the VHPs assumptions result in a conservative potential estimate. The following assumptions indicate the actual potential may be higher than what is reported in the VHP:

- The VHP assumes 50% of the stream reach is available for hydro system use. Other studies indicate this estimate is conservative. For example, a small hydro potential study produced for BC Hydro estimates 90% of stream flow is useable, deeming only 10% of flow needs to be retained to protect fish. Therefore, the actual potential at each site could be as much as 80% higher than the potential indicated in the VHP.[26]

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[26] Details of Idaho National Laboratory's identification and analysis of potential hydro sites listed in the VHP are given in the report: *Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants*, January 2006, Prepared for the DOE, Office of Energy Efficiency and Renewable Energy by Idaho National Laboratory.

- The study did not include potential for hydrokinetic technologies in cases where little head is available but there is sufficient velocity and stream depth to support such hydrokinetic technologies.

Potential from Hydro Prospector

The data for all potential projects in PSE territory were obtained from the VHP online tool. Though this study limited project size to 500 kW—generally the maximum allowable size for a behind-the-meter system—sites were included that had more potential, as we assumed part of the potential could be utilized. Table 49 shows the number of sites by county.

Table 49. Count of Potential Hydro Sites by County and Size Class

Size Class	<20 kW	20-30 kW	30-40 kW	40-60 kW	60-80 kW	80-100 kW	100-300 kW	300-500 kW	Total
Whatcom	19	12	4	11	5	4	49	75	179
Skagit	10	13	9	11	5	4	26	66	144
Jefferson	6	1	1	2	3	2	6	6	27
King	21	25	18	19	16	14	90	191	394
Pierce	3	7	4	7	1	5	25	61	113
Thurston	23	19	11	15	6	13	14	15	116
Kitsap	14	8	7	4	1	1	0	0	35
Kittitas	25	12	9	13	9	5	48	88	209
Island	0	0	0	0	0	0	0	0	0
Total	121	97	63	82	46	48	258	502	1,217

The total amount of technical potential by size range is shown in Table 50.

Table 50. Technical Potential by Site Size Class (aMW in 2029)

Size Class	<20 kW	20-30 kW	30-40 kW	40-60 kW	60-80 kW	80-100 kW	100-300 kW	300-500 kW	Total
Potential (aMW)	1.46	2.02	1.81	3.43	2.76	3.55	42.98	207.21	265.21

Note that these values may not agree with the distribution of potential hydro sites within a county; the exact location of the utility's operating areas within each county were not known. Based on available geographical data, sites outside PSE's electric territory were excluded.

To calculate generation per month, stream flow data were taken from the USGS Website.[27] These data, which show the stream flow for each month for different streams in each county, were used to estimate the proportion of total annual generation in each month by first calculating the percentage of annual stream flow (in each month) for the sample streams in that county, then applying that percentage to annual generation for the whole county.[28]

27 http://waterdata.usgs.gov/ia

28 The calculation can be represented as: Monthly generation (kWh) = kW potential x 8760 hours/year x the percentage of annual stream flow in the month.

This analysis showed the share of annual generation is distributed differently, depending on the part of the state in which the county is located. In addition, the total potential is much lower in summer than in winter, with the September flow only 34% of the peak flow in January. Further details are provided in Volume II, Appendix F.

Small Wind

The technical potential for small wind assumes all technologies will be installed by all customers living at available sites, regardless of cost or other market barriers. We began with PSE's customer forecast, weighted by zip code based on the 2000 Census. Then, for reasons described in-depth below, we applied the following conditions:

- Eliminated customers renting their homes;
- Excluded 95% of the urban population; and
- Excluded customers living close to an airport.

Population Density. Small wind turbines are currently less viable options for heavily populated regions due to the lack of land available for turbines and the interruption of air flow by tall buildings.[29] We determined population density at the zip code level using 2000 Census data; because of urban population density, we excluded 95% of residential customers. However, as some urban lots may be suitable for small wind, we kept 5%of the urban population in the technical potential. Census data also provided an estimate of renter-occupied versus owner-occupied homes by zip code. Renter-occupied homes are not expected to install turbines as renters will not be inclined to invest in such a location-specific measure.

Proximity to Airports. Wind turbines within 2 miles of an airport may be subject to tower height regulations by the Federal Aviation Administration (FAA).[30] Small wind turbines are unlikely to be affected by these height restrictions, but this assumption has been made to ensure a conservative resource estimate. Therefore, we excluded a portion of customers located near an airport.

After applying these screening criteria, it was determined it technically may be feasible to install a wind turbine at 134,384 PSE residential customer sites.

In addition to customer availability, the quantity of the wind resource is a major component to technical potential**.** Wind speeds are based on TMY2 data, which include wind speeds for three cities within or near PSE electric territory: Seattle, Yakima, and Olympia. We then assigned each zip code within PSE territory to one of these wind profiles, based on geographic proximity.

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29 Building integrated turbines are gaining greater acceptance in Europe and, in the future, may be deemed a viable option in the U.S. However, they have not been included in the analysis here due to insufficient acceptance levels in the U.S. and insufficient data availability.

30 AWEA. http://www.awea.org/smallwind/toolbox2/factsheet_visual_impact.html

Clean Energy Achievable Technical Potential

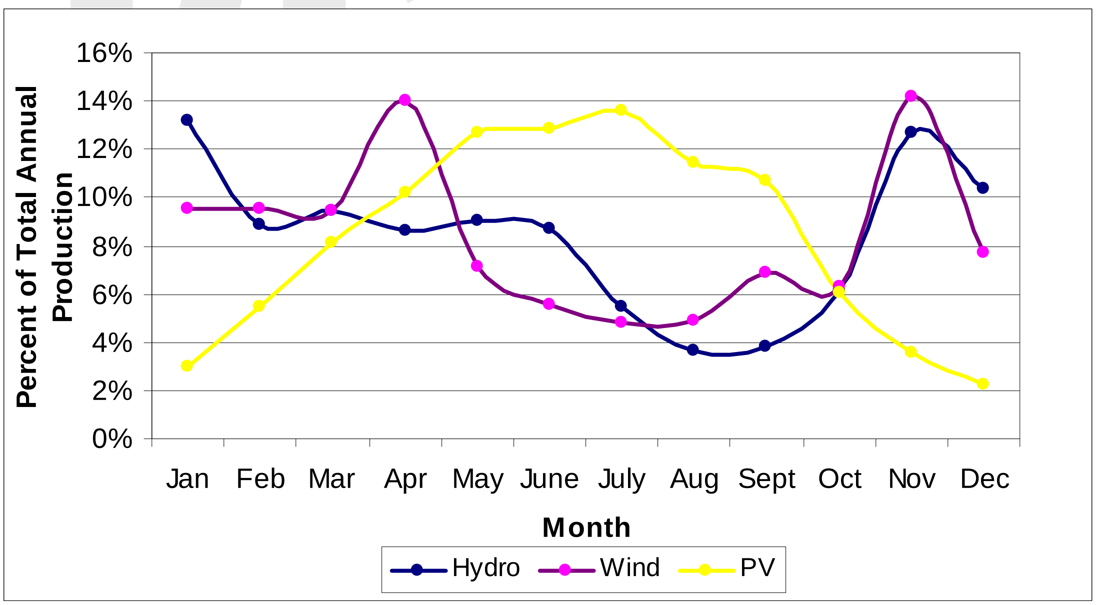
Achievable technical potential by technology is provided in Table 51. The industrial sector was not considered a market likely to install clean energy options. The total potential from all resources across PSE territory is 21 aMW. Note that none of the clean energy options are likely to be cost-effective, and the current achievable technical potential derives purely from customers willing to accept long payback periods. Details on derivation of this achievable technical potential are given below for each technology.

Table 51. Clean Energy Achievable Technical Potential (aMW) by Sector in 2029

Sector	Building PV	Small Hydro	Small Wind	Total
Residential	3.6	0.08	0.04	3.7
Commercial	17.3	0.04	0	17.3
Total	20.9	0.12	0.04	21.1
Levelized Cost ($/kWh)	$0.6	$0.1	$1.40	
Individual results may not sum to total due to rounding.				

All clean energy options are intermittent resources. For small hydro and wind, peak power generation occurs in winter; PV peaks in the summer. The variations in achievable technical potentials over the year for each technology are shown in Figure 29.

Figure 29. Clean Energy Average Monthly Achievable Technical Potential (2029)



Although none of the clean energy resources are likely to be considered cost-effective, changes from other factors may affect the payback period. These factors may include government incentives, technological breakthroughs that reduce costs, and future energy costs. It is difficult to quantify the payback period's affect on adoption, but decreasing the payback period to less than 10 years can have as much as a two- to three-fold increase in achievable technical potential.

Building PV

Achievable technical potential for PV is primarily based on the recent success of PV installations in PSE's service territory and knowledge of PSE's internal staff as well as on existing programs across the country. A program's success is, in part, dependent on the current incentives available. Incentives can be provided by one or more of the following: federal tax incentives, state tax incentives, utility buy-downs, production-based incentives, and other rebates. Volume II, Appendix F lists several state programs from around the country that offer PV incentives.[31] Incentives have become critical in promoting and creating a successful PV program. Depending on the type and size of the incentive, it can affect the adoption rate. In most instances, the total incentive is roughly 50% of the installed cost for the residential market and 75% for the commercial sector. The achievable technical potential is based on existing successful programs implementing these incentive levels, and is calculated from their adoption rates. The resulting achievable technical potential is less than 1% of the technical potential.

The resulting achievable technical potential is 21 aMW. The levelized cost for PV is $0.69 /kWh. If current federal tax credits and the production subsidy incentives remain, the levelized cost falls to $0.60/kWh.[32]

Small Hydro

Achievable technical potential for small hydro is difficult to analyze because very few utility or state programs promote hydro as a customer-based renewable resource. Currently in North America, the Energy Trust of Oregon, BC Hydro, and Holy Cross Energy (Colorado) all have some form of incentive program promoting small hydro. However, data available on program installations and potential are sparse, and thus could not be used for this assessment. Instead, it is assumed, based on discussions with PSE staff, that over the 20-year horizon, small hydro units would be installed at 10 residential sites (approximately 10 kW each) and one commercial site (approximately 50 kW).

Small Wind

The achievable technical potential estimates were based primarily on discussions with PSE staff and historical program activity. Based on this, it was assumed two to three 10 kW turbines will be installed per year, along with one 1.9 kW turbine. This leads to an overall installed nameplate capacity of 610 kW, or 0.04 aMW of energy generated from small wind in 2029. This value is an overall figure, as we assumed no achievable technical potential in the Yakima region, and most market penetration occurs near Seattle and Olympia, where wind conditions are most favorable.

[31] Database of State Incentives for Renewables and Energy Efficiency (DSIRE); www.dsireusa.org.

[32] Washington's production subsidy remains in effect until December 31, 2014, and the expanded Federal tax credits remain until December 31, 2016, after which point they are scheduled to revert to enacted EPAct 2005 incentive levels.