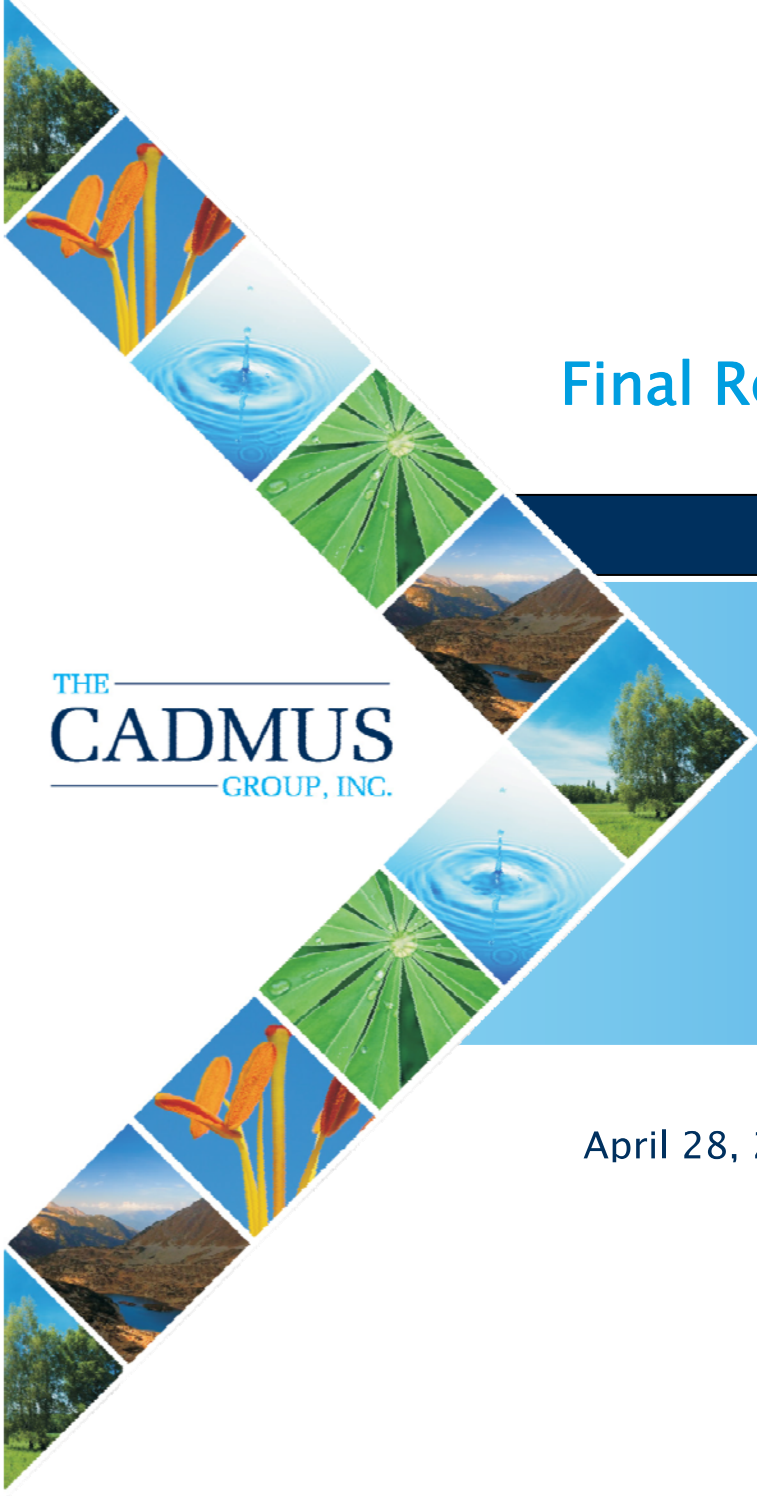

THE CADMUS GROUP, INC.

Final Report

Comprehensive Assessment of Demand-Side Resource Potentials (2012-2031)

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Prepared by:

The Cadmus Group, Inc. / Energy Services
720 SW Washington Street, Suite 400
Portland, OR 97205
503.228.2992

Prepared for:

Puget Sound Energy

Prepared by:
The Cadmus Group

M. Sami Khawaja, Ph.D.
Vice President
The Cadmus Group, Inc.

Corporate Headquarters:
57 Water Street
Watertown, MA 02472
Tel: 617.673.7000
Fax: 617.673.7001

An Employee-Owned Company
www.cadmusgroup.com

720 SW Washington St.
Suite 400
Portland, OR 97205
Tel: 503.228.2992
Fax: 503.228.3696

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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 resources (DSR) in Puget Sound Energy's (PSE's) service territory from 2012 to 2031. The study was commissioned by PSE as part of its biennial integrated resource planning (IRP) process.

The study, which builds upon previous efforts, incorporates updated baseline and DSR data informed by primary and secondary data collection. The study is also informed by 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 potential and achievable technical potential 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 Results

The potentials identified in this study are summarized in Table 1. As shown, electric demand-side resources account for 667 aMW and 1,208 winter peak MW of achievable technical potential by 2031. These potentials represent 19% of retail energy sales and 21% of winter peak demand[1]. Similarly, achievable technical natural gas potential accounts for 20% of forecasted 2031 retail sales. High-level potentials by resource are presented below, with more detailed results in the sections of this report that follow.

Table 1. Summary of Energy and Capacity Saving Potentials, Cumulative in 2031

	Energy (aMW / million therms)		Winter Coincident Peak Capacity (MW)	
Resource	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Electric Resources				
Energy Efficiency	961	645	1,497	985
Fuel Conversion	55	22	75	30
Demand Response	N/A	N/A	1,995	193
Electric Resources Total	1,016	667	3,567	1,208
Natural Gas Resources				
Energy Efficiency	427	268	N/A	N/A

Energy Efficiency

Table 2 shows 2031 forecasted baseline electric sales and potential by sector. As shown, the results of this study indicate 961 aMW of technically feasible electric energy-efficiency potential will be available by 2031, the end of the 20-year planning horizon. Once market constraints are

[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.

taken into account, this translates to an achievable technical potential of 645 aMW. Were all of this potential cost-effective and realizable, it would amount to an 18 percent reduction in 2031 forecasted retail sales and a reduction in forecasted load growth of roughly 50 percent. This study, consistent with the Council, assumes that 85 percent of electric resources will be achievable over time. However, due timing of lost opportunity resource acquisition, the achievable technical potential amounts to less than 85 percent of the technical potential, as described in greater detail in Section 1.

Table 2. Electric Energy-Efficiency Potential by Sector, Cumulative in 2031

		Technical Potential		Achievable Technical Potential	
Sector	Baseline Sales	aMW	Percent of Baseline Sales	aMW	Percent of Baseline Sales
Residential	1,620	566	35%	336	21%
Commercial	1,823	373	20%	291	16%
Industrial	111	22	20%	18	17%
Total	3,554	961	27%	645	18%

Table 3 shows 2031 forecasted baseline natural gas sales and potential by sector. As shown, the results of this study indicate roughly 427 million therms of technically feasible natural gas energy-efficiency potential by 2031. This translates to an achievable technical potential of 268 million therms. If all of this potential was cost-effective and realizable, it would amount to a 20 percent reduction in 2031 forecasted retail sales and a 68% reduction in forecasted load growth from 2012 to 2031.

Table 3. Natural Gas Energy-Efficiency Potential by Sector, Cumulative in 2031

		Technical Potential		Achievable Technical Potential	
Sector	Baseline Sales	Million Therms	Percent of Baseline Sales	Million Therms	Percent of Baseline Sales
Residential	846	303	36%	183	22%
Commercial	445	117	26%	80	18%
Industrial	31	7	21%	5	16%
Total	1,322	427	32%	268	20%

Comparison to 2009 IRP

The assessment of energy efficiency potential is largely an update of the analysis conducted for PSE's 2009 IRP. However, there are a number of differences between the two studies that have led to differences in technical, and thus, achievable technical potential, namely:

- Updated commercial baseline data from the Northwest Energy Efficiency Alliance's (NEEA's) Commercial Building Stock Assessment (CBSA)
- Utilization of PSE's most recent energy and sales forecasts
- Incorporation of assumptions, data, and new measures from the Council's 6th Northwest Power Plan
- Adjustments to remaining potential based on PSE's actual 2008-2009 and projected 2010-2011 energy efficiency program accomplishments
- Updated data on measure costs, savings, lifetime, and applicability
- Incorporation of new codes and standards, as described in Section 1 of this report.

A comparison of electric and natural gas technical potentials from the two studies, by sector, is presented in Table 4. As shown, the results of the two studies are similar, with the exception of electric potential in the residential sector, where potential has increased by approximately 65 percent, as compared to the 2009 IRP. This increase is driven largely by increased savings from measures included in the Council's 6th Plan, such as heat pump water heaters and consumer electronics. Additionally, the impact of upcoming residential lighting standards is being treated differently in this study, as described in Section 1, which has increased the remaining lighting potential.

Table 4. Comparison of Energy Efficiency Technical Potential, 2009 IRP to 2011 IRP

	Electric (aMW)		Natural Gas (million therms)	
Sector	2009 IRP	2011 IRP	2009 IRP	2011 IRP
Residential	343	566	263	303
Commercial	378	373	132	117
Industrial	17	22	12	7
Total	739	961	407	427

Fuel Conversion

The fuel conversion analysis estimates available potential from converting electric equipment to natural gas for two main customer types: customers in PSE's natural gas service territory who do not currently have natural gas service, and those who do, but still have electric equipment (i.e. water heaters or appliances) that could be converted to natural gas. Table 5 shows the available technical and achievable technical potential in 2031 for each type of customer.

Table 5. Summary of Fuel Conversion Potentials, Cumulative in 2031

	Technical Potential		Achievable Technical Potential	
Customer Type	Electric Savings (aMW)	Additional Gas Usage (million therms)	Electric Savings (aMW)	Additional Gas Usage (million therms)
Electric-Only	23.5	16.0	10.6	7.3
Existing Gas Customer	31.4	18.6	11.5	7.5
Total	54.9	34.6	22.1	14.8

Comparison to 2009 IRP

As for energy efficiency, this analysis is largely an update to the 2009 IRP. The analysis builds upon the same updated data mentioned above, including baseline data, PSE's sales and customer forecasts, and measure assumptions. Table 6 presents a comparison of the estimated technical and achievable technical potential, as compared to the 2009 IRP. Whereas the 2009 IRP included customers in Cascade Natural Gas service territory, this study addresses conversion only for customers in PSE's natural gas service territory. Additionally, this study incorporated expected participation rates based on PSE pilot program experience, leading to substantially lower potential for electric customers.

Table 6. Comparison of Fuel Conversion Potential, 2009 IRP to 2011 IRP

	Technical Potential (aMW)		Achievable Technical Potential (aMW)	
Customer Type	2009 IRP	2011 IRP	2009 IRP	2011 IRP
Electric-Only	136	24	50	11
Existing Gas Customer	38	31	15	12
Total	174	55	65	22

Demand Response

Table 7 presents estimated winter and summer resource potentials for all demand response resources for the residential, commercial, and industrial sectors. As shown, demand response achievable technical potential represents reductions of approximately 3 percent of forecasted 2031 winter and summer peaks.

Table 7. Demand Response Technical and Achievable Technical Potential, MW in 2031

	Winter			Summer		
Sector	Technical Potential	Achievable Technical Potential	Achievable Technical As Percent of System Peak	Technical Potential	Achievable Technical Potential	Achievable Technical As Percent of System Peak
Residential	1,184	110	1.95%	402	32	0.72%
Commercial	767	79	1.40%	783	82	1.85%
Industrial	44	4	0.08%	54	5	0.12%
Total	1,995	193	3.43%	1,239	119	2.68%
*System peak is based on PSE's average load in the top 20 hours for each season.						

Comparison to 2009 IRP

This study relies on the same methodologies used in the 2009 IRP analysis; however, the program strategies included differed. The 2011 IRP assessed one incentive-based and one pricing-based program strategy in each sector, whereas the 2009 IRP included multiple options. This decision reflected the structure of PSE's current demand response pilot programs, and to minimize the interactive effects between similar program options. A comparison of estimated achievable technical potential during peak periods, by sector, is presented in Table 8.

Table 8. Comparison of Demand Response Achievable Technical Potential, 2009 IRP to 2011 IRP

	Winter MW		Summer MW	
Sector	2009 IRP	2011 IRP	2009 IRP	2011 IRP
Residential	170	110	48	32
Commercial	14	79	14	82
Industrial	5	4	5	5
Total	189	193	68	119
*System peak is based on PSE's average load in the top 20 hours for each season.				

The largest difference in results between the two studies is in the commercial sector, where potentials have increased considerably. The results of the 2011 IRP are based on the structure of PSE's nonresidential pilot program and informed by its success. Residential potential has decreased due to removal of multifamily customers from the program concept.

Distributed Generation

Distributed generation potentials were not estimated as part of this study. PSE incorporated the results of the 2009 IRP analysis into its 2011 IRP. For detailed potentials from the 2009 IRP analysis, see the 2008 Cadmus' report.[2]

Comparison to the Council's 6th Plan

This study employs methodologies consistent with the Council's 6th Plan to estimate available energy-efficiency potential (See Appendix A for a detailed comparison of methodologies). Additionally, Cadmus conducted a thorough review of baseline and measure assumptions used by the Council, including costs, savings, applicability, and current saturation. Although this study relies on data specific to PSE's service territory whenever possible, Council assumptions were incorporated where appropriate.

By applying PSE's share of regional sales, by sector, to the Council's regional potential, one can estimate the 6th Plan's share of potential in PSE's service territory. However, there are a number of factors that must be considered in comparing that allocated potential to the results of this study:

- The Council, by necessity, relies on average regional data; whereas this study utilizes primary data from PSE's service territory. Therefore, an allocation of regional potential based on sales may not account for PSE's unique service territory characteristics, such as customer mix, use per customer, end use saturations, fuel shares, and current measure saturation. Similarly, some industries included in the 6th Plan may not exist in PSE's service territory.
- PSE and the Council rely on unique baseline energy forecasts, each of which is a major driver in the respective estimates of potential.
- Both studies assess potential over a 20-year period; however, the 6th Plan begins in 2010, while estimation of potential in this study begins in 2012.
- Due to the timing of the release of the 6th Plan, not all upcoming codes and standards were removed from the potential (most notably, new standards relating to commercial lighting and residential water heating, as described in Section 1 of this report).

These caveats aside, Table 9 provides a comparison of the 2-, 10-, and 20-year achievable technical potentials estimated in this study, as compared to the 6th Plan. The 6th Plan numbers are derived by applying PSE's share of regional sales, by sector, to the 6th Plan estimates[3] of regional potential.[4]

- In the residential sector, while the 6th Plan allocation of 10- and 20-year potentials are substantially higher, the two-year 2011 IRP savings is higher due to accelerated ramping.
- In the commercial sector, short- and long-term potentials from the 2011 IRP are substantially higher.

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2 http://www.pse.com/SiteCollectionDocuments/2009IRP/AppL1_IRP09.pdf

3 Bus bar savings from the 6th Plan have been adjusted to savings at the customer meter using the Council's line loss factors.

4 Report 6th Plan potentials by sector and end use are based on summarization of measure-specific Council workbooks available here: http://www.nwcouncil.org/energy/powerplan/6/supplycurves/default.htm

- In the industrial sector, 2- and 10-year potentials are very close, although the 6th Plan's 20-year potential is substantially higher.

Details on sector-level differences are provided below.

Table 9. Comparison of 2011 IRP and 6th Plan Achievable Technical Potential (aMW)

	2-Year Achievable Technical Potential		10-Year Achievable Technical Potential		20-Year Achievable Technical Potential	
Sector	2011 IRP	PSE Share of Regional Potential	2011 IRP	PSE Share of Regional Potential	2011 IRP	PSE Share of Regional Potential
Residential*	47	40	229	263	336	584
Commercial	43	14	230	115	284	227
Industrial	4	2	18	17	18	35
Total	93	56	478	394	638	845
* Solar photovoltaic potential has been removed from 6th Plan potential to allow for direct comparison between studies						

Residential Sector

As shown in Table 9, the residential sector accounts for the largest differences in estimates of long-term achievable technical potential. Because of differences in end-use definitions, it is difficult to compare the two studies at a detailed end-use level; however, Table 10 shows the distribution of 20-year potential by major end-use group for each study. Differences in assumptions by end use are described below:

- ***Appliances and water heating*** are combined for this comparison because a large portion of appliance potential is water heating savings from clothes washers and dishwashers. A key difference in the modeling approaches is the incorporation of new residential water heating standards in the 2011 IRP, as described in Section 1 of this report. It is assumed that new equipment installed after 2014 would need to meet the new minimum efficiency requirements, reducing the potential for high-efficiency water heating equipment. Additionally, there is a substantial difference in the assumed percentage of water heaters using electricity (42 percent in PSE's service territory versus 64 percent for the region).
- The category of ***consumer electronics and other plug loads*** contains a variety of end uses, including televisions, computers, and other household electronics. While the base-year saturations of the various types of equipment are similar between the two studies, the assumptions differ regarding how saturations may change over time, leading to a difference in long-term potential.[5] Additionally, the 6th Plan includes commercial computers and monitors as part of the residential potential, while the study performed by Cadmus includes only units in residences.
- ***HVAC*** encompasses heating, cooling, and ventilation savings, which are combined due to differences in model structures. The main drivers of this difference are assumed saturation of central cooling (15 percent in PSE's service territory versus 53 percent for the region) and the share of electric heating (15 percent for PSE's service territory versus 35 percent for the region).

[5] The 2011 IRP assumes annual increases in saturations by technology ranging from 0.3% to 1.0% based on the EIA's 2010 Annual Energy Outlook. Council escalation assumptions vary by technology with an average annual increase of around two percent.

- ***Lighting*** savings in the 2011 IRP assumes a technology that meets the minimum requirements of the Energy Independence and Security Act of 2007 (EISA) will be available and that savings from CFL installations will still be available.

Table 10. Comparison of 20-Year Residential Achievable Technical Potential by End Use

	20-Year Achievable Technical Potential	
End Use Group	2011 IRP	PSE Share of Regional Forecast
Appliances and Water Heating	89	213
Consumer Electronics and Other Plug Loads	61	125
HVAC	125	202
Lighting	56	43
Total	366	584

Commercial Sector

Although in the commercial sector, this study estimates higher 2-, 10-, and 20-year achievable technical potential than does the 6th Plan, this difference is largely a function of differing load forecasts. Both studies estimate that approximately 16 percent of year-20 commercial sales could be saved; however, PSE forecasts its load to be approximately 20 percent higher than its allocation of the regional commercial sales forecast. Higher potential in the early years of this study is due to the 10-year acceleration of all discretionary potential.

Industrial Sector

Because the two assessments rely on the same measure assumptions, differences in potential are driven by the mix of industries present. For example, in the Northwest region on the whole, pulp and paper industries account for the largest portion of both baseline sales and achievable technical potential (roughly 30 percent and 40 percent, respectively). However, in PSE's service territory, these facilities account for less than 1 percent of baseline consumption. Additionally, PSE's forecasted industrial sales are approximately 30-percent lower than its allocated share of the regional forecast.

Incorporation of Demand Side Resources into PSE's IRP

The achievable technical potential shows above were grouped by levelized cost of conserved energy for inclusion in PSE's IRP model. Note, levelized costs are calculated over a measure's life, even if that life extends past the end of the planning horizon. Bundling resources into a number of distinct cost groups allows the model to select the optimal amount of DSR annually based on expected load growth, energy prices, and other factors.

Figure 1 shows the annual cumulative combined potential for energy efficiency, fuel conversion, and distributed generation by each of the cost bundles considered in PSE's 2011 IRP. Figure 2 shows the annual DSR bundles for natural gas energy efficiency.

Figure 1. Annual Electric DSR Bundles by Cost Group

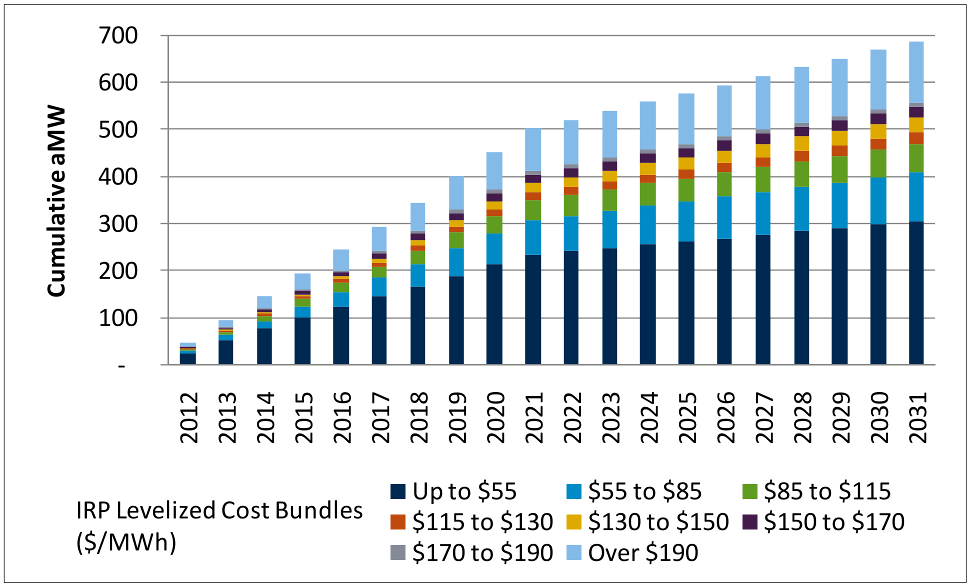
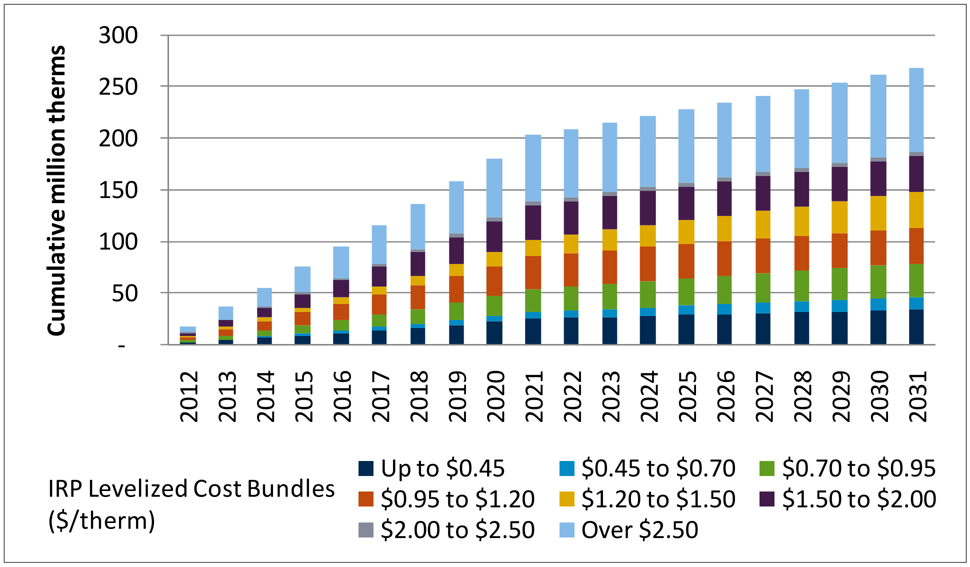


Figure 2. Annual Natural Gas DSR Bundles by Cost Group



In addition to the energy efficiency, fuel conversion, and distributed generation bundles displayed above, PSE included three other resource bundles in its IRP:

1. The expected effects on residential lighting due to EISA (shows graphically in Figure 3),
2. Capacity-only impacts of demand response, and
3. Savings associated with distribution efficiency improvements (outside the scope of this study).

Organization of the Report

The remainder of this report is organized in four sections. The first outlines the general methodology for assessment of potential for each resource type, while the remaining three sections present the key assumptions and results for each resource. Additional technical information and descriptions of data and their sources are presented in the appendices to this document.

1. General Approach and Methodology

This report describes the technologies, data inputs, data sources, data collection processes, and all assumptions used in the calculation of technical and achievable technical long-term potentials.

General Approach

The demand-side resources (DSR) 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 aim to arrive at estimates of two distinct types of potential: technical and achievable technical.

Technical potential assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. It is important to note that the notion of technical potentials is less relevant to resources (such as demand response) since nearly all end-use loads may be subject to interruption or displacement by on-site generation from a strictly technical point of view.

Achievable technical potential is defined as that portion of technical potential that might be assumed to be achievable in the course of the planning horizon, regardless of the acquisition mechanism. (For example, savings may be acquired through utility programs, improved codes and standards, or market transformation.) The identified potential is then grouped by levelized cost, allowing PSE's IRP model to pick the optimal amount of DSR, given various assumptions around future resource requirements and costs. In addition to the up-front capital cost and annual energy savings, the levelized cost calculation incorporates several other factors, consistent with the Council's methodology:

- ***Incremental operations and maintenance (O&M) costs or benefits*** are considered annually over the life of the measure. The present value is used to adjust the levelized cost- upward for measures with costs above baseline technologies and downward for measures that decrease O&M costs.
- ***Non-energy benefits*** are treated as a reduction in levelized costs for measures that save resources in addition to the primary fuel being considered. This includes secondary fuel benefits (e.g. natural gas savings for electric measures) as well as reductions in consumption of water, detergent, or other applicable resources.
- ***The regional ten percent conservation credit, capacity benefits during PSE's system peak, and transmission and distribution (T&D) deferrals*** are similarly treated as reductions in levelized cost for electric measures**.**

In addition to the quantity of available potential, the timing of resource availability is a key consideration. For this analysis, resources are split into two distinct categories:

- ***Discretionary resources*** are retrofit opportunities in existing facilities that, theoretically, are available at any point over the course of the study period.
- ***Lost opportunity resources*** are those with pre-determined availability, such as replacement after equipment failure and opportunities in new construction.

Data Sources

The full assessment of resource potential required the compilation of a large set of measure-specific technical, economic, and market data obtained from secondary sources and through primary research. The main sources of data used in this study included:

- ***PSE Internal Data.*** This encompasses historical and forecasted sales and customers, hourly load profiles, and historic DSR accomplishments
- ***Primary Data.*** This study relies on several sources of data specific to PSE's service territory and customers. These sources include the 2008 Residential End Use Survey, 2008 Fuel Conversion Survey, 2007 CFL Saturation Study, and NEEA's 2009 Commercial Building Stock Assessment (CBSA).
- ***Secondary Pacific Northwest Sources.*** Several Northwest entities provided data critical to this study, including the Council, the Regional Technical Forum (RTF), and the Northwest Energy Efficiency Alliance (NEEA). This included technical information on measure savings, costs, and lives, hourly end-use load shapes (to supplement building simulations described above), and commercial building and energy characteristics.
- ***Additional Secondary Sources.*** The study relied on a number of secondary sources to characterize measures, assess baseline conditions, and benchmark results against other utilities' experiences. These sources include the California Energy Commission's Database of Energy Efficiency Resources (DEER), ENERGY STAR, the Energy Information Administration, and various utilities' annual and evaluation reports on energy efficiency and demand response programs.

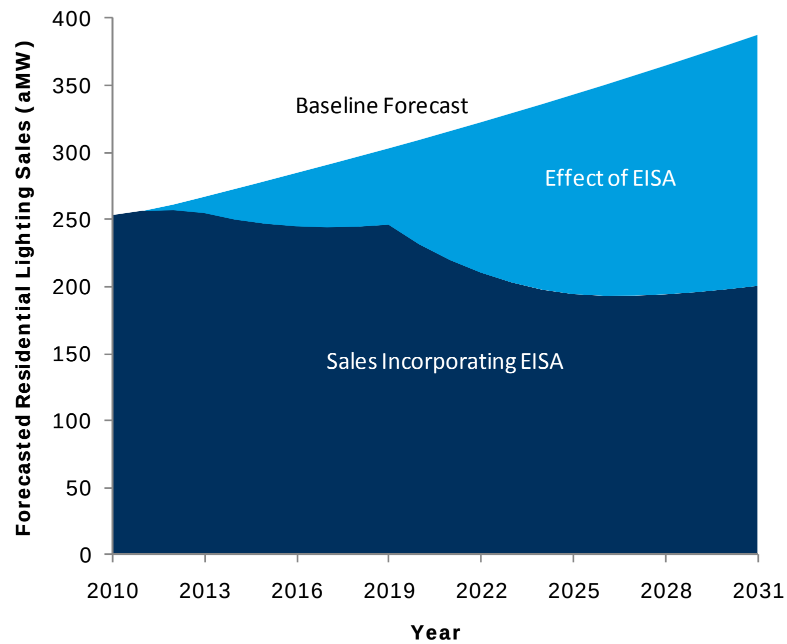
Incorporation of Upcoming Codes and Standards

While Cadmus' analysis does not attempt to predict how energy codes and standards may change, it does capture legislation that has been enacted, even if it will not go into effect for several years. The most notable, recent efficiency regulation is the Energy Independence and Security Act of 2007 (EISA), which set new standards for general service lighting, motors, and other end use equipment. It is particularly important to capture the effects of this legislation because residential lighting has played a large role in PSE's energy efficiency programs over the past several years.

EISA requires that general service lighting becomes roughly 30 percent more efficient than current incandescent technology, with standards phased in by wattage from 2012 to 2014. In addition to the 2012 phase-in, EISA contains a backstop provision that requires still higher efficacy beginning in 2020.

To ensure an accurate assessment of remaining lighting potential, Cadmus created a new forecast netting out EISA's effect on residential lighting (Figure 3). This was based on a strict interpretation of the legislation, assuming that affected bulbs would be replaced with technologies meeting EISA minimum standards, meaning savings from CFL and LED technologies would still exist. Note that PSE's 2009 IRP assumed CFLs would become the *de facto* baseline after the codes took effect, thus eliminating the potential for CFLs.

Figure 3: Residential Lighting Forecasts Before and After EISA Adjustment



While the new residential lighting standards have the largest effect on potential, several other codes and standards were explicitly accounted for in this study. Specifically, these:

- Current Washington state energy code (as of 2010)
- Residential water heating standards established on April 16, 2010, and taking effect in 2015, setting new requirement for Efficiency Factor (EF)[6]: The analysis assumes that, beginning in 2015, all new equipment installed will meet these minimum efficiency requirements.

Table 11. 2015 Residential Water Heater EF Requirements

Equipment Type	55 Gallons and Below	56 Gallons and Above
Electric Storage	EF = 0.960 - (0.0003 × Rated Storage Volume in gallons)	EF = 2.057 - (0.00113 × Rated Storage Volume in gallons)
Gas-fired Storage	EF = 0.675 - (0.0015 × Rated Storage Volume in gallons)	EF = 0.8012 - (0.00078 × Rated Storage Volume in gallons
Gas-fired Instantaneous	EF = 0.82	

- Two commercial lighting standards are phased in over the study horizon. First, as of July 2010, Department of Energy standards mandate that magnetic ballasts be phased out and replaced with electronic ballasts. In addition, standards require that all T-12 lamps be phased-out beginning in July 2012.[7] These standards are modeled as a percentage reduction to the lighting end use intensity (EUI), phased in upon ballast replacement. The EUI reduction is based on two factors:

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6 http://www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/htgp_finalrule_fedreg.pdf

7 http://www1.eere.energy.gov/buildings/appliance_standards/residential/fluorescent_lamp_ballasts.html

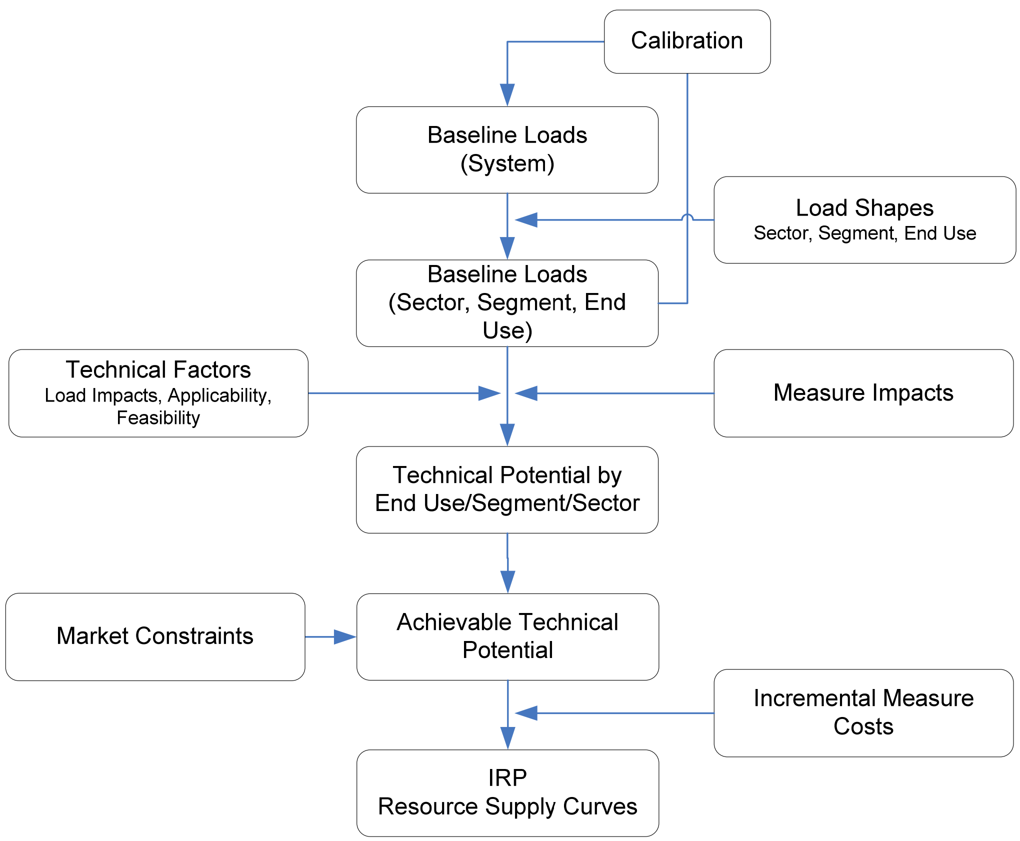
1. The difference in wattage between a T-12 lamp with a magnetic ballast and a T-8 lamp with an electronic ballast, and,
2. The percentage of floor space lit by T-12 lamps, as estimated by the 2009 CBSA.

The remainder of this section outlines the specific methodologies used for each resource.

Energy Efficiency

The methodology used for estimating the technical and achievable technical energy-efficiency potential is based on standard industry practices. This methodology is consistent with that of the Council in its assessments of conservation potentials for the 6th Northwest Regional Power Plan (6th Plan). The general approach, shown in Figure 4, illustrates how baseline and efficiency data are combined to develop estimates of potential for use in PSE's IRP process.

Figure 4. General Methodology for Assessment of Energy Efficiency Potentials



Developing Baseline Forecasts

As shown, the first step entails creating a baseline (no-DSR) forecast. In the residential and commercial sectors, the analysis relies on a bottom-up forecasting approach, beginning with annual consumption estimates by segment, end use, and efficiency level of equipment. Average base-year use per customer is then calculated from the saturations of equipment, fuel, and efficient equipment. These estimates are validated by comparison to PSE's historical use per customer, and a forecast of future energy sales is then created based on expected new construction and equipment turnover rate.

In the industrial sector, as is standard practice, PSE's industrial forecast is disaggregated to end uses based on data available from the EIA's Manufacturing Energy Consumption Survey.

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. Cadmus conducted the analyses for the following customer segments:

- 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),
- 17 industrial segments (17 facility types, treated only as an existing construction vintage)

Estimating Technical Potential

To estimate technical potential, a comprehensive list of measures was developed for all sectors, segments, and end uses. For the residential and commercial sectors, the study begins with a review of a broad range of energy-efficiency measures. These measures are then screened to include only those measures that are: (1) commonly available, (2) based on well-understood technology, and (3) applicable to PSE's buildings and end uses.

The industrial sector measures were based on the Council's 6th Plan and other general categories of process improvements.[8]

The study encompasses 309 *unique* electric energy-efficiency measures and 106 unique gas energy-efficiency measures (Table 12). When expanded across segment, end use, and construction vintage, this amounts to over 6,000 measures. (A comprehensive list of measures included in the analysis is provided in Appendix B.2, with inputs and outputs provided in Appendix B.3.)

Table 12. Energy-Efficiency Measure Counts by Fuel

Sector	Electric Measure Counts	Gas Measure Counts
Residential	89 unique, 922 permutations across segments	48 unique, 409 permutations across segments
Commercial	138 unique, 2,503 permutations across segments	50 unique, 908 permutations across segments
Industrial	82 unique, 1,145 permutations across segments	8 unique process improvements, 124 permutations across segments

For every measure permutation contained in the study, a number of key inputs—varying by segment and end use—were compiled, specifically, these:

8 Industrial improvements are derived from a variety of practices and specific measures defined in DOE's Industrial Assessment Centers Database, http://www.iac.rutgers.edu/database/.

- ***Measure savings.*** The energy savings associated with a measure as a percentage of the total end-use consumption. Sources include engineering calculations, energy simulation modeling, the Regional Technical Forum (RTF), the Council's 6th Plan, and secondary sources such as Energy Star and DEER.
- ***Measure costs.*** The per-unit cost (either full or incremental, depending on the application) associated with installation of the measure. Sources include the Council's 6th Plan, DEER, RS Means, and merchant Websites.
- ***Measure life.*** The expected useful life (EUL) of the measure. Sources include the Council's 6th Plan, DEER, and demand-side management (DSM) program evaluations.
- ***Measure applicability.*** A general term encompassing a number of factors, such as the technical feasibility of installation, the current saturation of the measure, measure interaction, and competition. Where possible, applicability factors are based on PSE survey data.

An alternate sales forecasts was created, incorporating the effects of all technically feasible measures, and the difference between this forecast and the baseline forecast represents the technical potential. This method allows for long-term estimates of technical potential by measure, while accounting for changes in baseline conditions inherent in the baseline forecast.

Achievable Technical Potential

"Achievable technical potential" is defined as that portion of technical potential expected to be reasonably achievable over the course of the planning horizon. This estimate accounts for likely rates of acquisition and market barriers to customer adoption, but it does not address cost-effectiveness or acquisition mechanism (utility programs, codes and standards, market transformation, etc.). Thus, the amount of savings a utility can expect to acquire cost-effectively may be substantially lower than this estimate.

This study, consistent with the Council's 6th Plan, assumes an achievability factor for electric energy efficiency of 85 percent. For lost opportunity measures, this number (which is applied directly to the total technical potential for discretionary measures) is ramped in at a rate determined by the technology. Because of this ramp-up, less than 85 percent of the lost opportunity potential will be acquired over the planning horizon, consistent with the Council's methodology[9].

Due to higher up-front cost of equipment for gas resources, it is assumed that 75 percent of the technical potential could be achieved over the planning horizon.

As discussed previously, lost opportunity measures have an inherent technical ramping based on new construction and equipment turnover rates. In contrast, discretionary opportunities can be acquired at any point. For this study, it is assumed that all achievable electric and gas discretionary measures can be acquired in 10 years. This 10-year accelerated ramp-in for discretionary measures is considered by PSE to be a reasonable representation of the overall rate

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[9] This is consistent with the Council's assumption that 65 percent of lost opportunity resources can be acquired, as discussed in: *A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions,* April 2007 - http://www.nwcouncil.org/library/2007/2007-13.htm

of energy savings acquisition for resource planning analyses. It should be noted that actual market ramp rates will vary for specific measures.

Fuel Conversion

In the context of this study, “fuel conversion” refers to electric savings opportunities involving substitution of natural gas for electricity through replacement of space heating systems, water heating equipment, and appliances. Fuel conversion is only considered for existing single-family homes, new multifamily buildings, and both existing and new commercial facilities. These segments are considered the most likely and able to convert.

Cadmus’ analysis is an extension of the energy-efficiency analysis described above, identifying applicable equipment and customers based on the following criteria:

- Customers must be within PSE’s combined service territory. That is, areas where PSE provides both electricity and natural gas.
- Customers must be either existing gas customers or on a gas main.
- For existing construction, customers must have a ducted system for space heating conversion.
- New natural gas equipment must meet energy-efficiency program criteria (90 percent AFUE furnace, ENERGY STAR water heater, etc.).

Once eligible populations for each equipment type are identified, measure costs and savings are compiled, consistent with the energy-efficiency analysis. Cadmus also accounts for additional up-front costs required due to the natural gas conversion (line extensions, piping, etc.). The cost of natural gas consumed over the life of the measure, calculated based on forecasted avoided costs, is treated as an O&M cost and is included in the calculation of the cost of conserved electricity.

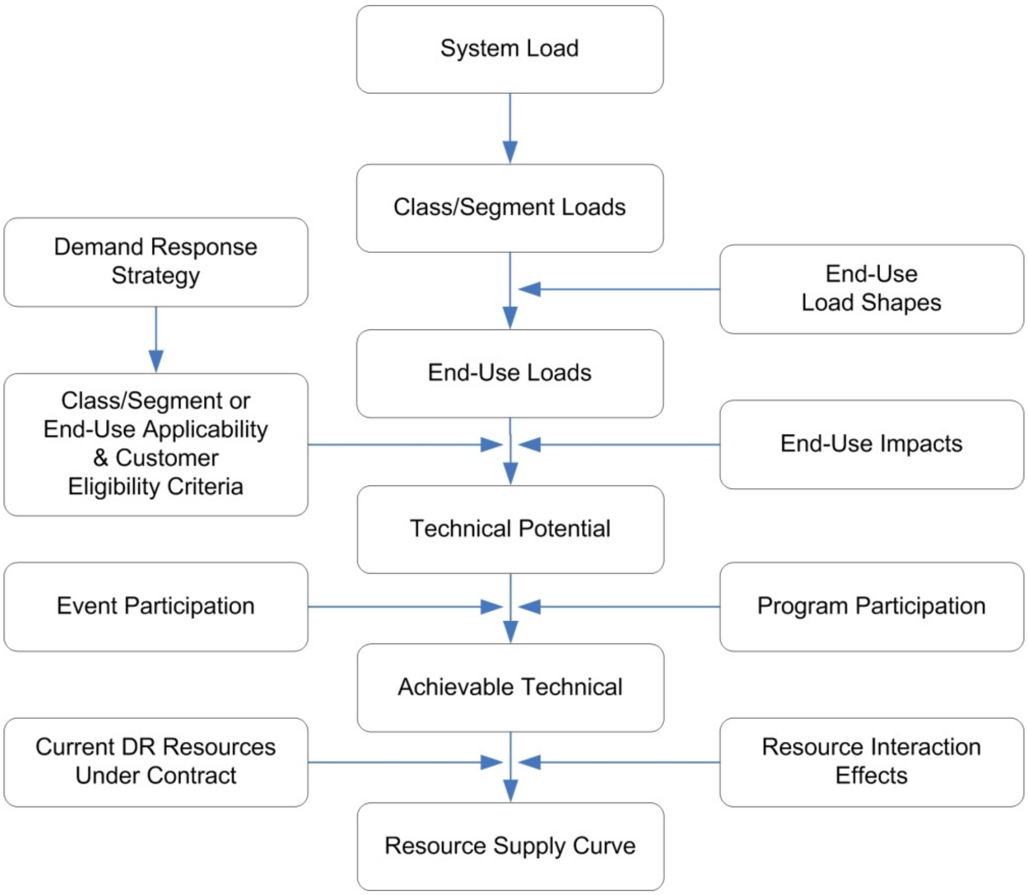
As with energy efficiency, the technical potential assumes all eligible pieces of equipment are converted to natural gas. Achievability is based on the results of PSE’s 2008 fuel conversion survey, which asked customers about their likelihood of participating at various incentive levels. Based on this survey, this analysis assumes 63 percent achievability, the value associated with PSE covering the entire incremental cost of conversion. Available potential is assumed to be acquired in equal amounts annually over the planning horizon.

Demand Response

The methodology for estimating demand response potential is illustrated in Figure 5. The approach begins with utility system loads, which are disaggregated by sector, segment, and applicable end use. For each program strategy, technical potential impacts are calculated for all applicable end uses.

Note that technical potential for demand response resources is not particularly useful for planning, as it tends to be much higher than what can actually be attained. For example, nearly every central air conditioner could, in theory, be controlled. However, in practice, program and event participation rates are likely to be much lower than 100 percent, depending on the program strategy. To estimate achievable technical potential, these expected rates are applied by program strategy to inform the IRP process.

Figure 5. Schematic Overview of Demand Response Assessment Methodology



Identify Eligible Loads

Estimation of both technical and achievable technical demand-response potential requires an understanding of available loads in peak periods by sector, segment, and end use. These loads are identified through the following steps:

1. ***Estimate the hourly demand by sector, segment, and end use.*** This task begins with the baseline forecast by sector, segment, and end use. Annual energy consumption for each combination is spread over hourly end-use loadshapes to estimate the demand in every hour of the year. To ensure the appropriateness of the loadshapes, hourly end-use demand is aggregated to the sector and system levels and compared to PSE's actual hourly loads.
2. ***Develop a list of program strategies for inclusion in analysis.*** The list of strategies was designed to include both price- and incentive-based options for all major customer segments and end uses in PSE's service territory. The list is informed by the 2009 IRP, PSE's demand response pilot program experience, and programs offered by other utilities.

3. ***Define the applicable sectors, segments and end uses for each program strategy.*** Not all loads analyzed in Step 1 will be candidates for any given demand response program strategy. Therefore, for each program strategy, applicable sectors, segments, and end uses are identified, establishing the peak demand that the given program can target.

Estimating Technical Potential

Technical potential (TP) for each demand response program is assumed to be a function of:

- customer eligibility in each class,
- affected end uses in that class, and
- the expected strategy impact on the targeted end uses.

Analytically, technical potential for each demand-response program strategy *(p)* is calculated as the sum of impacts at the end-use level (*e*) generated in customer segment (*s*) by the strategy:

$$TP_{pes} = LE_{ps} \times LI_{pes}$$

and

$$TP_p = \sum TP_{pes}$$

where,

LE_{ps} (load eligibility) represents the percent of customer segment (*s*) loads applicable for program strategy (*p*), referenced as "Eligible Load" in the program assumptions; and

LI_{pes} (load impact) is the percentage reduction in end-use load (*e*) for each segment (*s*) resulting from the program (*p*), referenced as "Technical Potential as a percent of Load Basis" in the program assumptions.

Estimating Achievable Technical Potential

Achievable technical potential is a subset of technical potential that accounts for the customers' ability and willingness to participate in capacity-focused programs subject to their unique business priorities, operating requirements, and economic (price) considerations.

For each program strategy, achievable technical potential is calculated by adjusting the technical potential by two factors:

- expected rates of program participation (percent of eligible load that would sign up for the program)
- event participation (percent of signed-up load that would participate in a given event)

Estimates of each factor were informed by PSE's program experience and/or secondary research. Assumptions for each program strategy are detailed in Section 4.

Demand-response programs vary significantly with respect to both the type and magnitude of costs. Applicable resource acquisition costs for demand-response strategies generally fall into two categories: (1) fixed direct expenses, such as infrastructure, administration, and data acquisition; and (2) variable costs, such as incentive payments to participants. Annual costs and impacts over the 20-year horizon are calculated based on available potential, assumed rate of acquisition, and participant attrition, allowing for a calculation of the levelized cost ($/kW-year) of each program strategy and allowing for comparison to supply-side alternatives. Estimates of achievable technical potential are combined with per-unit resource costs to produce resource supply curves.

Distributed Generation

Distributed generation potentials were not estimated as part of this study. PSE incorporated the results of the 2009 IRP analysis into its 2011 IRP. For detailed potentials from the 2009 IRP analysis, see the 2008 Cadmus' report.[10]

[10] http://www.pse.com/SiteCollectionDocuments/2009IRP/AppL1_IRP09.pdf

2. Energy-Efficiency Potentials

Scope of Analysis

The primary objective for 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 potential 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. The remainder of this section is divided into two parts: (1) a summary of resource potentials by fuel, and (2) detailed results by fuel and sector.

Summary of Resource Potentials – Electric

Table 13 shows 2031 forecasted baseline electric sales and potential by sector.[11] As shown, the results of this study indicate 961 aMW of technically feasible electric energy-efficiency potential will be available by 2031, the end of the 20-year planning horizon. This translates to an achievable technical potential of 645 aMW. Were all of this potential cost-effective and realizable, it would amount to an 18 percent reduction in 2031 forecasted retail sales and a reduction in projected load growth of roughly 50 percent.

Table 13. Electric Energy-Efficiency Potential by Sector, Cumulative in 2031

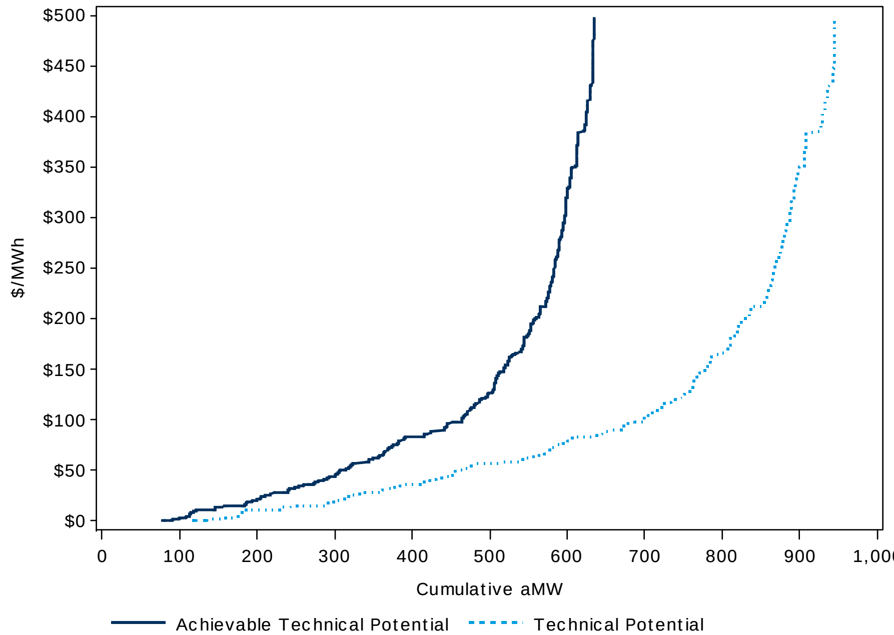
		Technical Potential		Achievable Technical Potential	
Sector	Baseline Sales	aMW	Percent of Baseline Sales	aMW	Percent of Baseline Sales
Residential	1,620	566	35%	336	21%
Commercial	1,823	373	20%	291	16%
Industrial	111	22	20%	18	17%
Total	3,554	961	27%	645	18%

Figure 6 illustrates the relationship between identified technical potential and achievable technical potential and the corresponding cost of conserved electricity.[12] As an example, there is approximately 500 aMW of achievable potential available at a cost of less than $120 per MWh.

11 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.

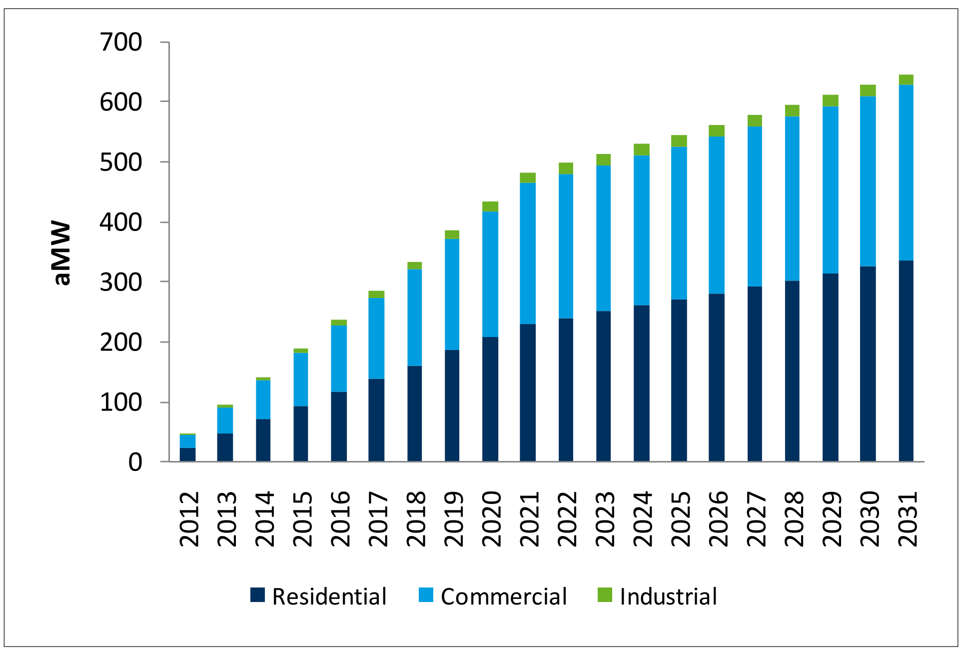
12 In the calculation of levelized cost of conserved energy, non-energy benefits are treated as a negative cost. This leads to some measures having a negative cost of conserved energy, although there would be an incremental up-front cost.

Figure 6. Electric DSR Supply Curves – Cumulative in 2031



The cumulative potential available in each sector annually is presented in Figure 7. The 10-year acceleration of discretionary resources leads to the change in slope after 2021.

Figure 7. Electric Energy Efficiency Acquisition Schedule by Sector



Summary of Resource Potentials – Natural Gas

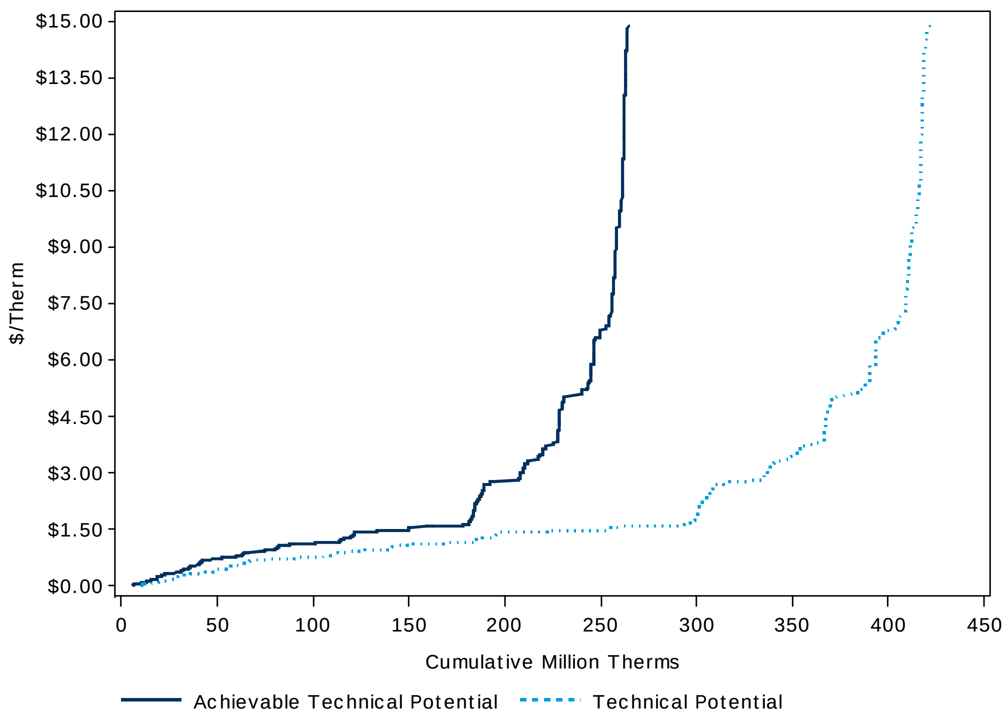
Table 14 illustrates the 2031 forecasted baseline natural gas sales and potential by sector. As shown, the results of this study indicate roughly 427 million therms of technically feasible energy-efficiency potential by 2031, the end of the 20-year planning horizon. This translates to an achievable technical potential of 268 million therms. If all of this potential was cost-effective and realizable, it would amount to a 20-percent reduction in 2031 forecasted retail sales, offsetting approximately 68 percent of forecasted load growth from 2012 to 2031.

Table 14. Natural Gas Energy-Efficiency Potential by Sector, Cumulative in 2031

		Technical Potential		Achievable Technical Potential	
Sector	Baseline Sales	Million Therms	Percent of Baseline Sales	Million Therms	Percent of Baseline Sales
Residential	846	303	36%	183	22%
Commercial	445	117	26%	80	18%
Industrial	31	7	21%	5	16%
Total	1,322	427	32%	268	20%

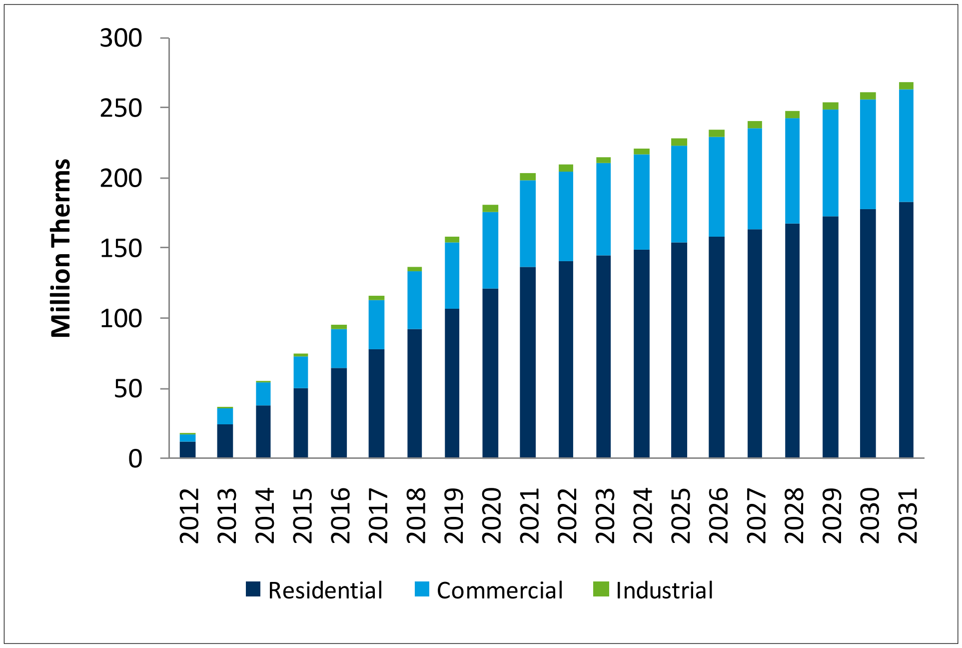
Figure 8 illustrates the relationship between identified technical potential and achievable technical potential and the corresponding cost of conserved energy. As an example, there are roughly 120 million therms of achievable potential available at a cost of less than $1 per therm.

Figure 8. Natural Gas DSR Potential Supply Curves, Cumulative in 2031



The cumulative potential available in each sector annually is presented in Figure 9. As with electric potential, the study assumes all achievable discretionary opportunities will be acquired over ten years.

Figure 9. Natural Gas Energy Efficiency Acquisition Schedule by Sector



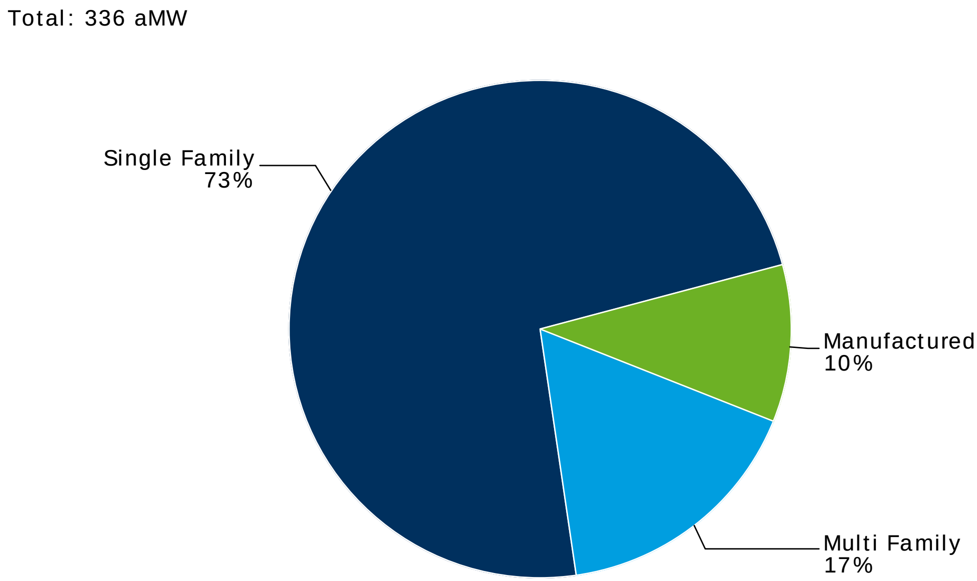
Detailed Resource Potentials

Residential Sector – Electric

Residential customers in PSE's service territory are expected to account for almost one-half of baseline electric retail sales by 2031. 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 and LED light bulbs). As described in Section 1, the expected impacts of new lighting standards established through EISA have been removed from the potential presented in this section.

As shown in Figure 10, single-family homes represent 73 percent of the total achievable technical residential electric potential, followed by multifamily (16 percent) and manufactured homes (9 percent). The main driver of these results is each home type's proportion of baseline sales, but other factors play an important role in determining potential, such as heating fuel sources,. For example, a higher percentage of manufactured homes are heated electrically than other home types, which increases their relative share of the potential. However, manufactured homes are typically smaller than detached single-family homes, ***and*** per-customer energy use is lower, so the same measure may save less in a manufactured home than in a single-family home. Volume II, Appendix B.3 provides a comprehensive list of the factors that impact segment-level energy-efficiency potential.

Figure 10. Residential Electric Achievable Technical Potential by Segment, Cumulative in 2031



Heating end uses represent the largest portion (27 percent) of achievable technical potential. Water heating, lighting, and consumer electronics also represent over 10 percent of the total identified potential. Because the analysis assumes an EISA-minimum lighting baseline, a considerable amount of energy-efficiency potential remains in the lighting end use, even after EISA effects have been removed from the baseline forecast. Figure 11 shows the total achievable technical potential by end-use group. Detailed potentials by end use are presented in Table 15.

Figure 11. Residential Electric Achievable Technical Potential by End Use, Cumulative in 2031

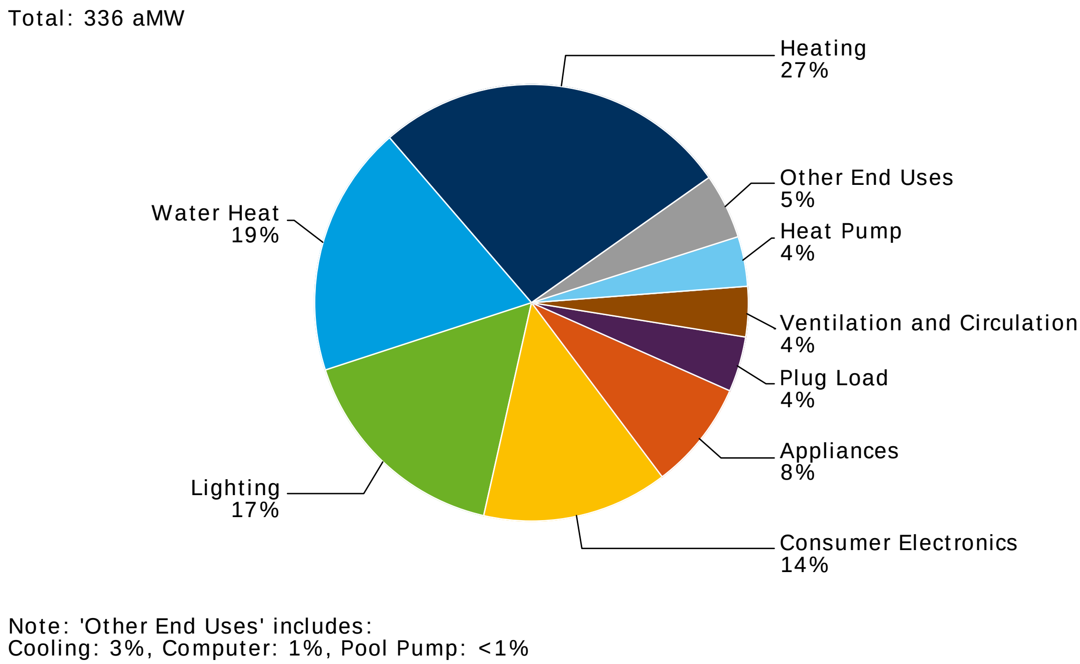


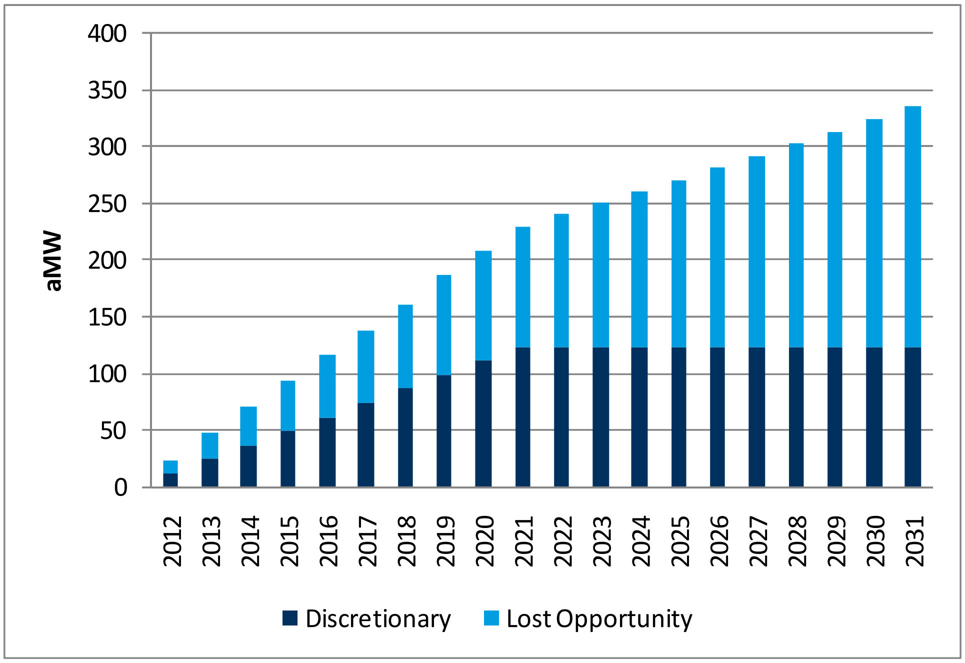
Table 15. Residential Electric Potential by End Use, Cumulative in 2031

End Use	Baseline Sales (aMW)	Technical Potential aMW	Technical Potential Percent of Baseline Sales	Achievable Technical Potential aMW	Achievable Technical Potential Percent of Baseline Sales
Appliances	288	42	14%	27	9%
Computer	37	10	27%	5	13%
Consumer Electronics	222	86	39%	46	21%
Cooling	27	14	52%	10	38%
Heat Pump	43	17	40%	12	29%
Heating	298	143	48%	90	30%
Lighting	198	121	61%	56	28%
Other Plug Loads	163	18	11%	14	9%
Pool Pump	6	2	42%	1	23%
Ventilation and Circulation	81	29	35%	13	15%
Water Heat	257	84	33%	62	24%
Total	1,620	566	35%	336	21%

Additional details regarding the savings associated with specific measures assessed within each end use are provided in Volume II, Appendix B.3.

Figure 12 shows annual cumulative achievable technical potential by resource type for the sector. Discretionary measures are acquired in equal increments over a ten-year period and account for 37 percent of cumulative achievable technical potential in 2031.

Figure 12. Residential Electric Annual Cumulative Achievable Technical Potential by Resource Type

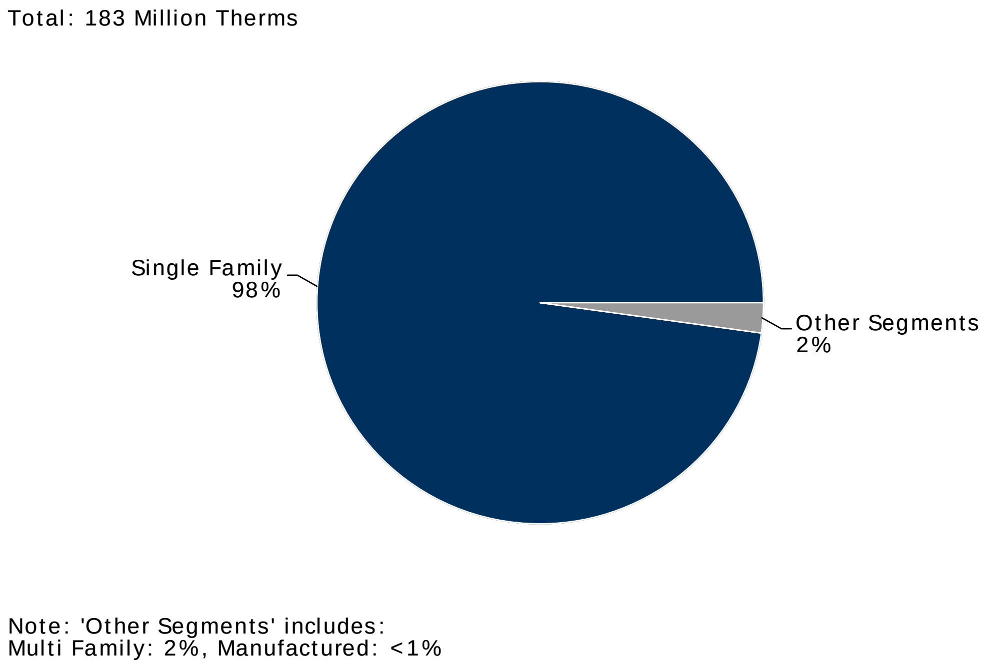


Residential Sector – Natural Gas

By 2031, residential customers are expected to account for over 55 percent of PSE's natural gas sales. Unlike residential electricity consumption, relatively few natural gas-fired end uses exist (primarily, space heating, water heating, and appliances); however, significant energy savings opportunities remain available. Based on resources used in this assessment, the achievable technical potential in the residential sector is expected to be about 183 million therms over 20 years, corresponding to a 19-percent reduction of forecasted 2031 sales.

Single-family homes account for 98 percent of the identified achievable technical potential, as shown in Figure 13. Due to lack of gas connections, only two percent of total achievable technical potential is in multifamily and manufactured residences.

Figure 13. Residential Natural Gas Achievable Technical Potential by Segment, Cumulative in 2031



The space heating and water heating end uses account for over 99 percent of the identified achievable technical potential (Figure 14). This potential is a combination of high-efficiency equipment (such as condensing furnaces and water heaters) and retrofits (such as shell measures, duct and pipe insulation, and low-flow showerheads). Detailed potentials by end use are presented in Table 16.

Figure 14. Residential Natural Gas Achievable Technical Potential by End Use, Cumulative in 2031

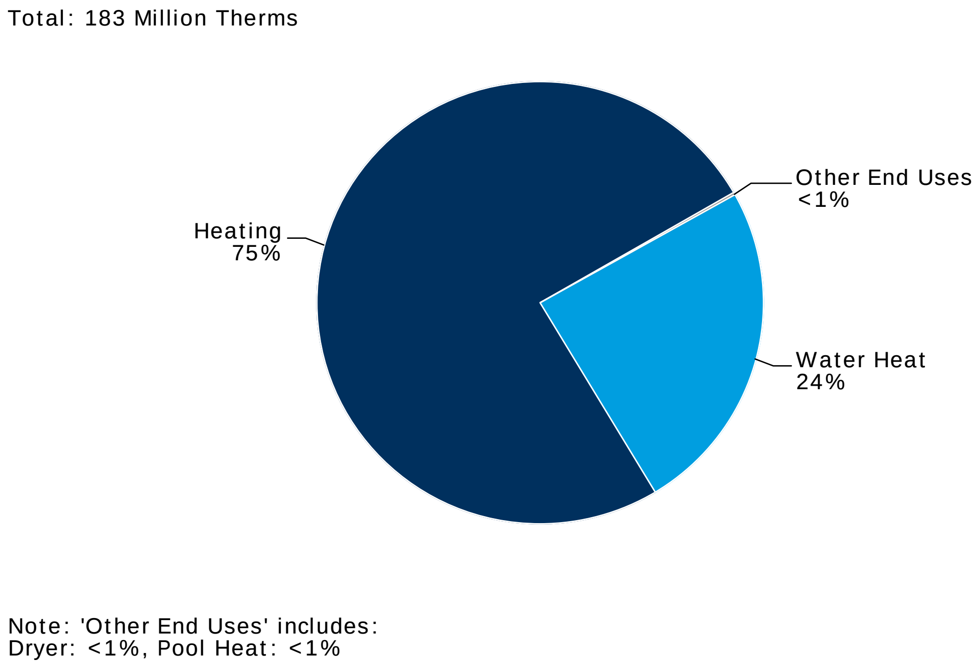
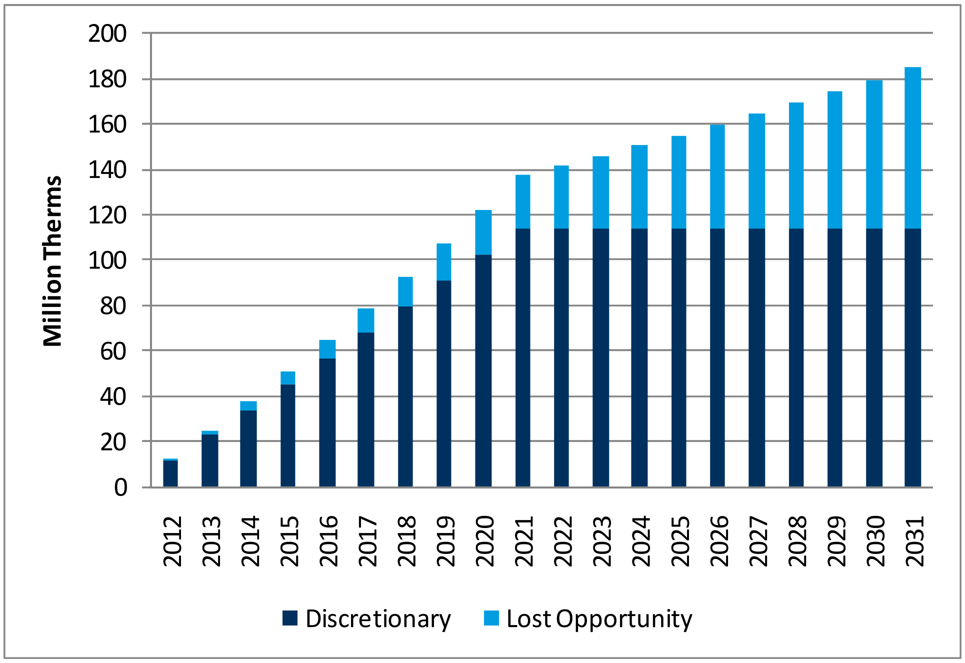


Table 16. Residential Natural Gas Potential by End Use, Cumulative in 2031

End Use	Baseline Sales (Million Therms)	Technical Potential		Achievable Technical Potential	
		Million Therms	Percent of Baseline Sales	Million Therms	Percent of Baseline Sales
Cooking	16	0	0%	0	0%
Dryer	8	1	7%	0	3%
Heating	554	219	40%	138	25%
Miscellaneous End Uses	23	0	0%	0	0%
Pool Heat	5	0	5%	0	3%
Water Heat	240	83	35%	45	19%
Total	830	303	37%	183	22%

Figure 15 shows residential natural gas annual cumulative achievable technical potential by resource type. Discretionary measures are acquired in equal increments over a ten-year period and account for 61 percent of cumulative achievable technical potential in 2031.

Figure 15. Residential Natural Gas Annual Cumulative Achievable Technical Potential by Resource Type

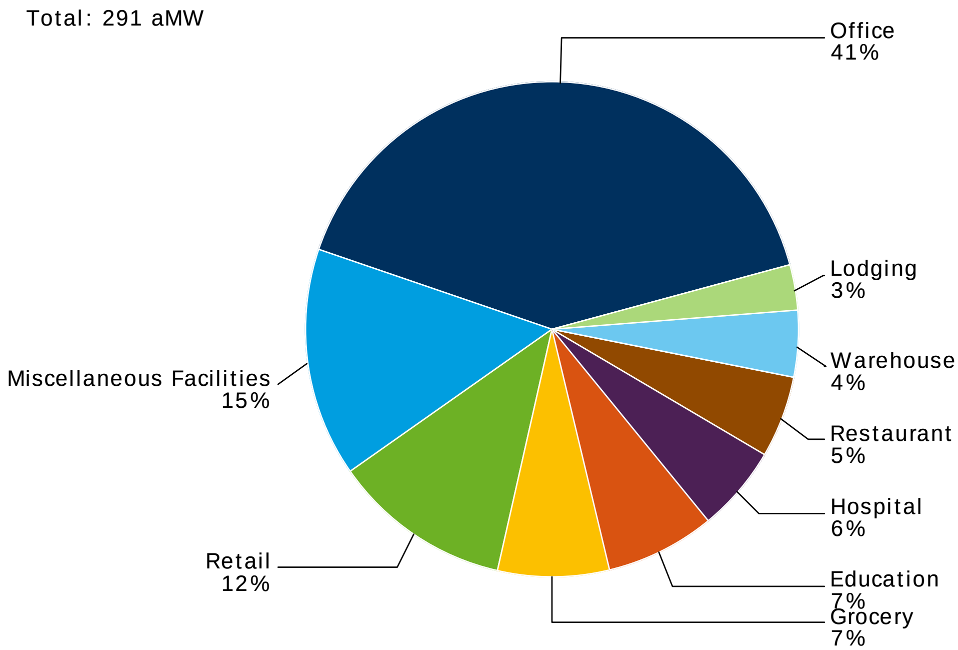


Commercial Sector – Electric

Based on resources included in this assessment, electric achievable technical potential in the commercial sector is expected to be 291 aMW over 20 years, a 17 percent reduction in forecasted 2031 commercial sales.

As shown in Figure 16, offices represent almost half of the available potential (41 percent). Miscellaneous facilities (15 percent) also represent a large portion of available potential. The miscellaneous segment consists of customers who do not fit into any of the other categories and customers for whom there is not enough information to be classified.

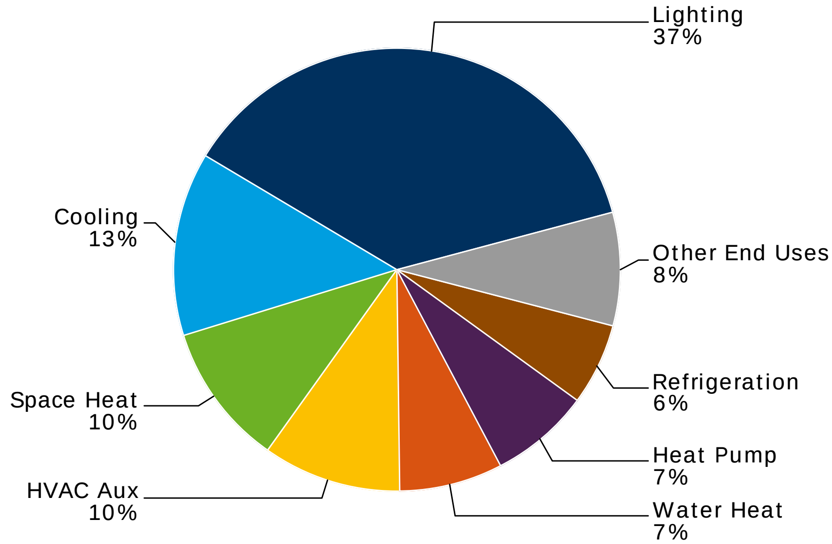
Figure 16. Commercial Electric Achievable Technical Potential by Segment, Cumulative in 2031



Lighting efficiency improvements represent by far the largest portion of achievable technical potential in the commercial sector (37 percent), followed by cooling (13 percent), space heating (10 percent), and HVAC auxiliary (10 percent), as shown in Figure 17. The large lighting potential entails bringing existing buildings to code and exceeding code in new and existing structures. Table 17 shows how baseline sales and savings are distributed across end uses.

Figure 17. Commercial Electric Achievable Technical Potential by End Use, Cumulative in 2031

Total: 291 aMW



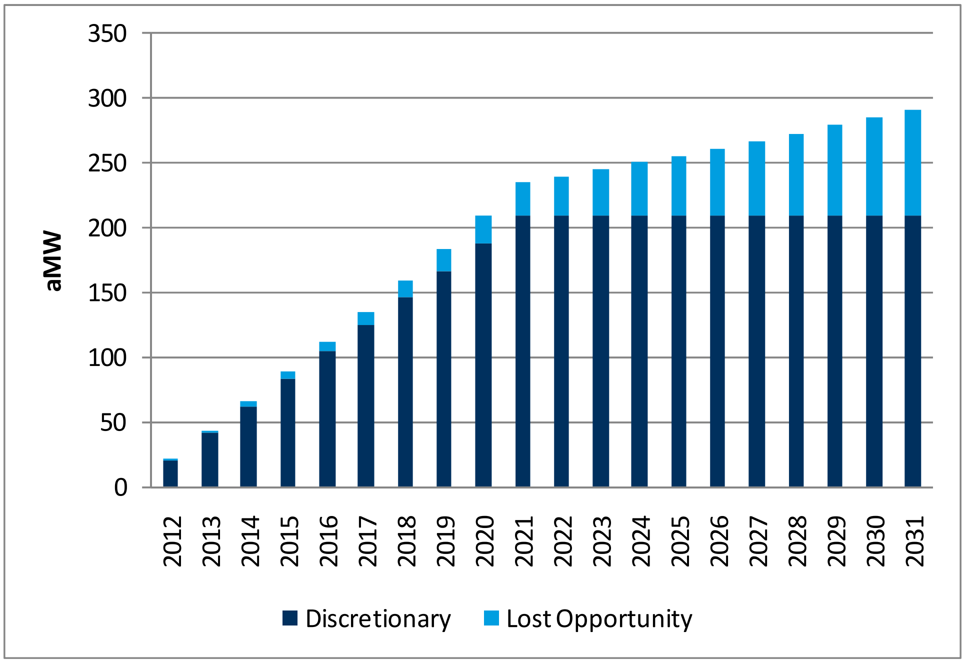
Note: 'Other End Uses' includes:
Plug Load: 5%, Computers: 3%, Cooking: <1%

Table 17. Commercial Electric Potential by End Use, Cumulative in 2031

End Use	Baseline Sales (aMW)	Technical Potential		Achievable Technical Potential	
		aMW	Percent of Baseline Sales	aMW	Percent of Baseline Sales
Computers	64	18	28%	9	15%
Cooking	24	1	4%	1	3%
Cooling	111	49	44%	39	35%
HVAC Auxiliary	299	38	13%	29	10%
Heat Pump	78	28	36%	21	27%
Lighting	757	134	18%	108	14%
Other Plug Loads	208	17	8%	14	7%
Refrigeration	105	22	21%	17	16%
Space Heat	102	36	36%	30	30%
Water Heat	74	29	39%	22	29%
Total	1,823	373	20%	291	16%

Figure 18 shows commercial electric annual cumulative achievable technical potential by resource type. Discretionary measures are acquired in equal increments over a ten-year period and account for 72 percent of cumulative achievable technical potential in 2031.

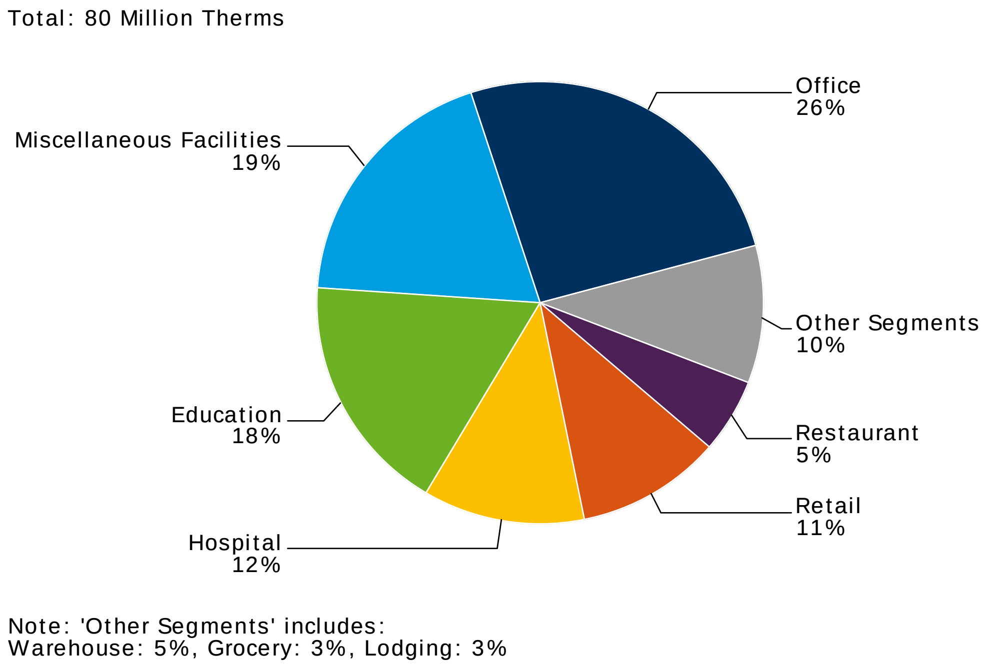
Figure 18. Commercial Electric Annual Cumulative Achievable Technical Potential by Resource Type



Commercial Sector – Natural Gas

Based on resources included in this assessment, natural gas achievable technical potential in the commercial sector is expected to be 80 million therms over 20 years, an 18 percent reduction in forecasted 2031 commercial sales. Achievable technical natural gas potential in the commercial sector represents about one-third of the total identified potential across all sectors. For electric customers, office buildings represent the largest portion of potential (26 percent, Figure 19). Significant amounts of achievable technical potential are also available in miscellaneous facilities (19 percent) and education buildings (18 percent).

Figure 19. Commercial Natural Gas Achievable Technical Potential by Segment, Cumulative in 2031



As in the residential sector, there are far fewer gas-fired end uses than electric end uses. Space heating accounts for 76 percent of the identified potential, and the remaining potential is mostly in water heating (21 percent), with small amounts in cooking and pool heating (Figure 20 and Table 18).

Figure 20. Commercial Natural Gas Achievable Technical Potential by End Use, Cumulative in 2031

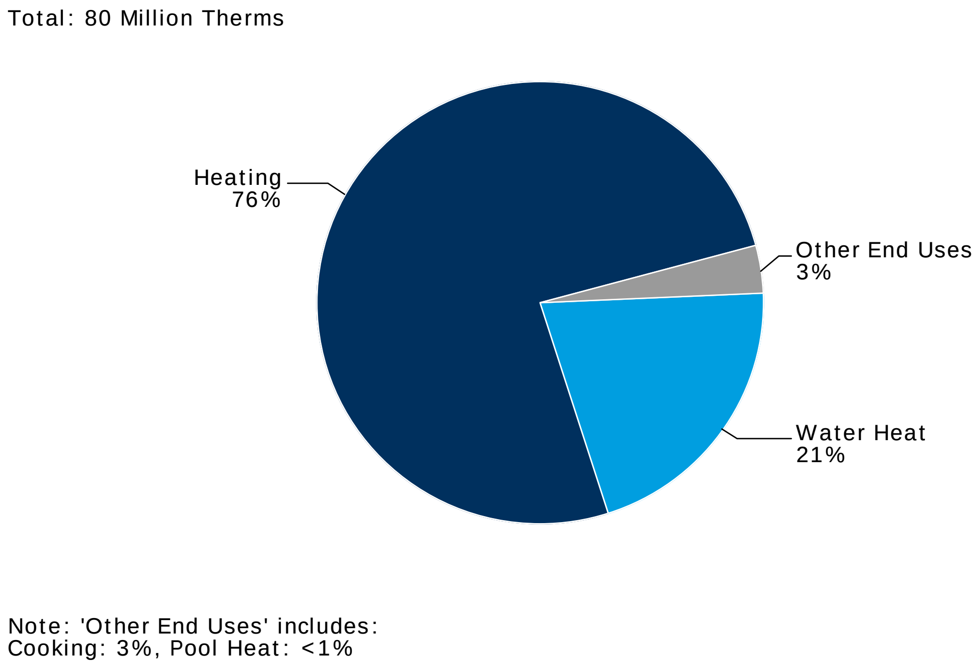
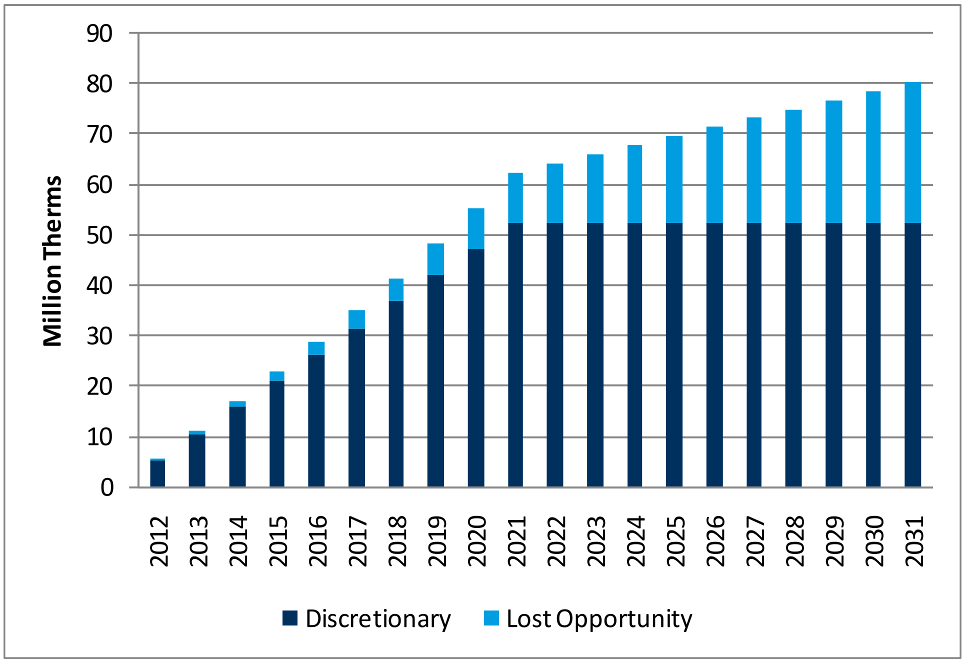


Table 18. Commercial Natural Gas Potential by End Use, Cumulative in 2031

		Technical Potential		Achievable Technical Potential	
End Use	Baseline Sales (Million Therms)	Million Therms	Percent of Baseline Sales	Million Therms	Percent of Baseline Sales
Cooking	62	3	5%	2	3%
Heating	293	88	30%	60	21%
Pool Heat	6	1	18%	1	13%
Water Heat	84	25	30%	17	20%
Total	445	117	26%	80	18%

Figure 21 shows commercial natural gas annual cumulative achievable technical potential by resource type. Discretionary measures are acquired in equal increments across a ten year period and account for 65 percent of cumulative achievable technical potential in 2031.

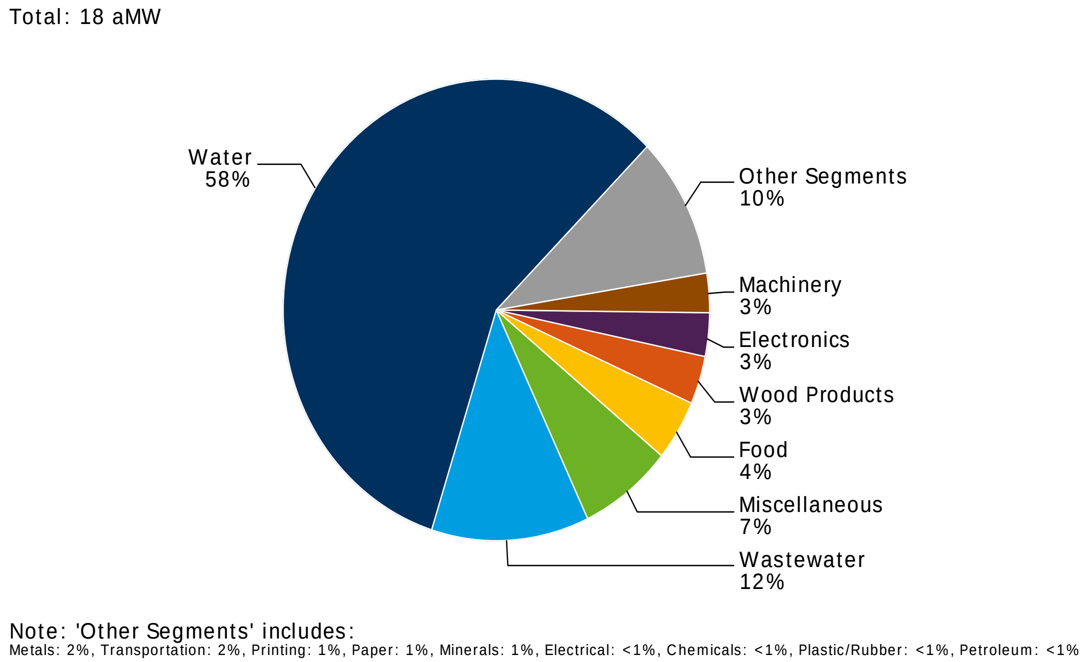
Figure 21. Commercial Natural Gas Annual Cumulative Achievable Technical Potential by Resource Type



Industrial Sector – Electric

Technical and achievable technical energy-efficiency potential 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 B.1.) Across all industries, achievable technical potential totals approximately 18 aMW over the 20-year planning horizon, corresponding to an 18 percent reduction of forecasted 2031 industrial consumption.

Figure 22. Industrial Sector Electric Achievable Technical Potential by Segment



The majority of electric achievable technical potentials in the industrial sector (50 percent) are in pumps, shown in Figure 23. Process improvement measures (16 percent) and fans (12 percent) also comprise significant portions of available technical potential. A small amount of additional potential exists for lighting and other facility improvements. Detailed potentials by end use are presented in Table 19. All industrial measures are considered discretionary with savings acquired over a ten-year timeframe.

Figure 23. Industrial Electric Achievable Technical Potential by End Use, Cumulative in 2031

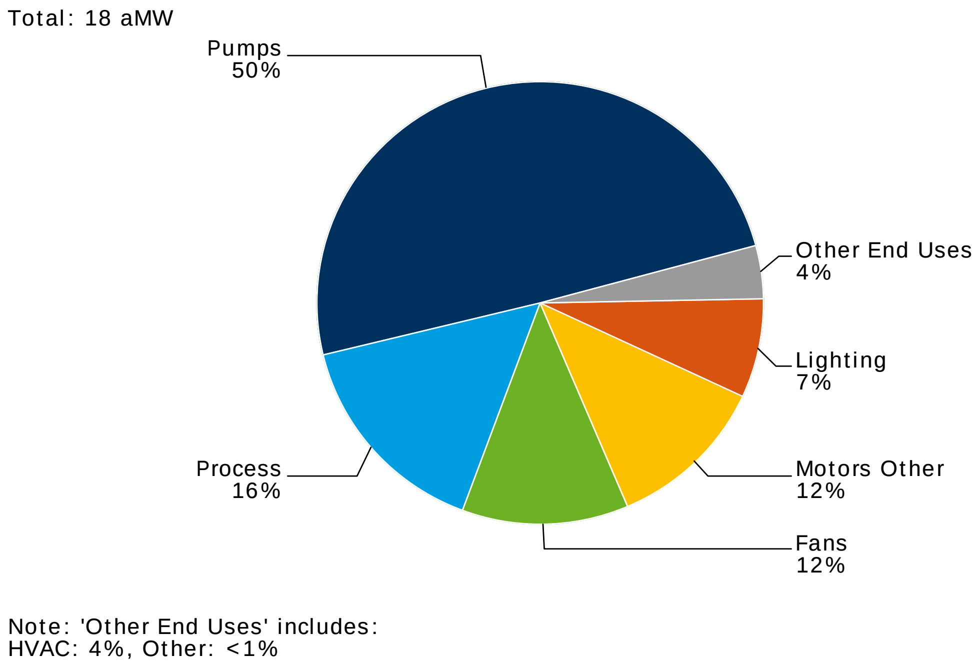


Table 19. Industrial Electric Potential by End Use, Cumulative in 2031

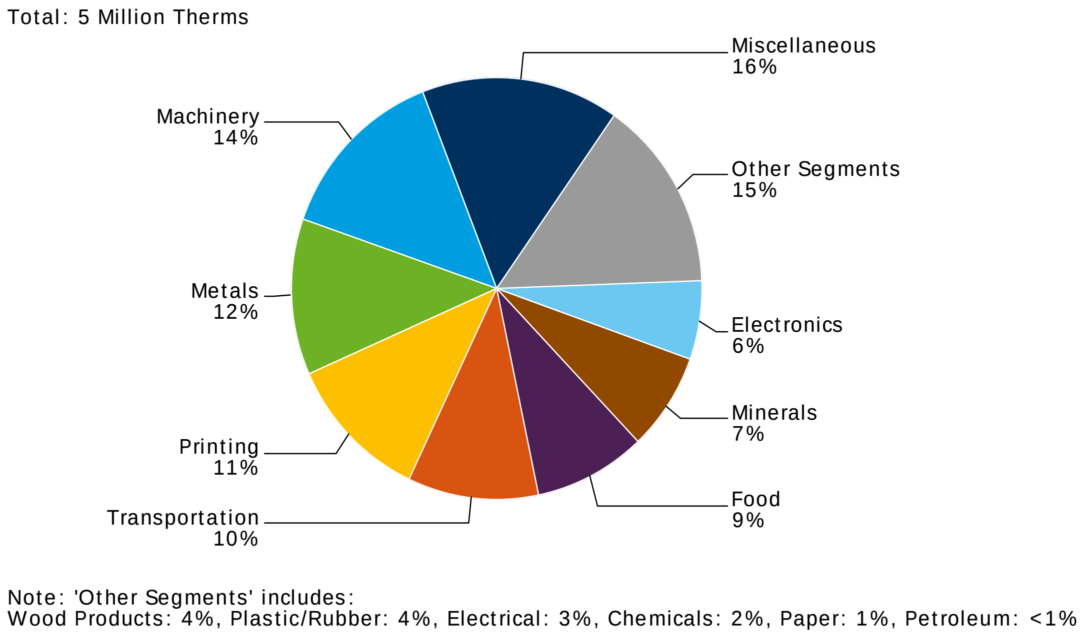
End Use	Baseline Sales (aMW)	Technical Potential		Achievable Technical Potential	
		aMW	Percent of Baseline Sales	aMW	Percent of Baseline Sales
Fans	8	3	33%	2	28%
HVAC	10	1	8%	1	7%
Indirect Boiler	1	0	0%	0	0%
Lighting	8	2	20%	1	17%
Motors Other	15	3	17%	2	14%
Other	10	0	0%	0	0%
Process	23	3	14%	3	12%
Pumps	36	11	30%	9	26%
Total	**111**	**22**	20%	**18**	17%

Industrial Sector – Natural Gas

Most industrial processes and end uses are powered by electricity and, thus, the industrial sector represents a small portion of natural gas baseline sales and potential.

Across all industries, achievable technical potential totals approximately 5 million therms over 20 years. Although this represents 16 percent of forecasted 2031 industrial sales, it accounts for only 2 percent of the achievable technical potential across the three sectors. As shown in Figure 24, substantial achievable technical potential lies in miscellaneous manufacturing (16 percent), machinery (14 percent), metals (12 percent), and paper (11 percent).

Figure 24. Industrial Natural Gas Achievable Technical Potential by Segment, Cumulative in 2031



Half of the achievable technical potential comes from process heating improvements. The remaining potentials are in HVAC and boiler improvements (Figure 25 and Table 20**).** All industrial measures are considered discretionary with savings acquired over a ten-year timeframe.

Figure 25. Industrial Natural Gas Achievable Technical Potential by End Use

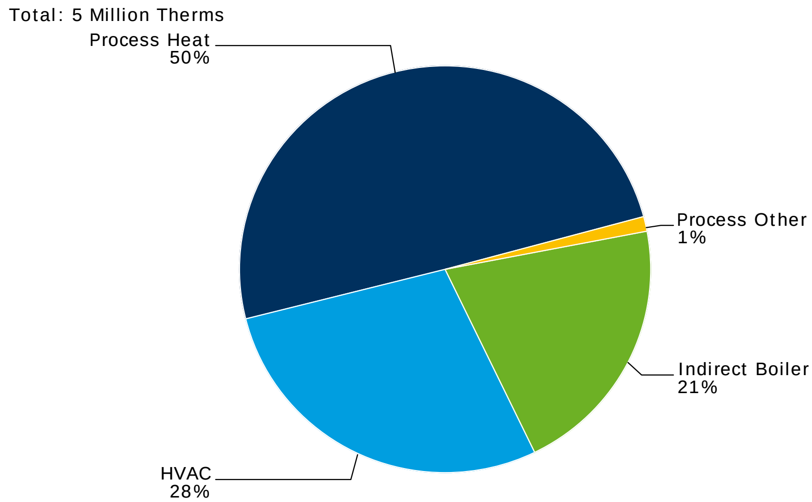


Table 20. Industrial Natural Gas Potential by End Use, Cumulative in 2031

		Technical Potential		Achievable Technical Potential	
End Use	Baseline Sales (Million Therms)	Million Therms	Percent of Baseline Sales	Million Therms	Percent of Baseline Sales
HVAC	9	2	21%	1	15%
Indirect Boiler	9	1	16%	1	12%
Other	0	0	0%	0	0%
Process Heat	12	3	27%	2	20%
Process Other	1	0	9%	0	6%
Total	31	7	21%	5	16%

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.

In the area where PSE provides both gas and electric service, fuel conversion potentials were examined for existing residential single-family homes, existing and new commercial buildings, and new multifamily structures. Three end uses were included in the analysis for single and multifamily homes: space heating, water heating, and appliances (clothes dryers and cooking ranges). For new multifamily homes, the potential from conversion of electric baseboard heating to natural gas furnaces was also included in Cadmus’ analysis. For commercial buildings, only space and water heating end uses were analyzed.

Summary of Resource Potentials

Fuel conversion technical potentials were calculated by assuming all applicable customers and end uses would be converted. As part of the 2009 IRP, 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. Based on this survey, approximately 63 percent of respondents indicated they would either be likely or highly likely to convert from electric to gas space heating if the utility were to pay 100 percent of the cost. As such, the achievable technical potential is assumed to be 63 percent of the technical potential. In the absence of comparable primary data, the same percentage was used for the commercial sector.

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

The cumulative electric technical potential from fuel conversion by 2031 is estimated at 55 aMW. Acquisition of the indicated electricity savings would, however, result in increased gas consumption of about 35 million therms by 2031. After making the adjustments for achievability described above, the total achievable technical electric savings potential of fuel conversion in 2031 is estimated at just over 22 aMW. This achievable technical potential corresponds to increased gas consumption of about 15 million therms.

Technical and achievable technical potential by customer type and market segment are shown in Table 21 and Table 22, respectively

Table 21. Fuel Conversion Potentials by Customer Type, Cumulative in 2031

Customer Type	Technical Potential		Achievable Technical Potential	
	Electric Savings (aMW)	Additional Gas Usage (million therms)	Electric Savings (aMW)	Additional Gas Usage (million therms)
Electric-Only	23.5	16.0	10.6	7.3
Existing Gas Customer	31.4	18.6	11.5	7.5
Total	54.9	34.6	22.1	14.8

Table 22. Fuel Conversion Potentials by Market Segment, Cumulative in 2031

Market Segment	Technical Potential		Achievable Technical Potential	
	Electric Savings (aMW)	Additional Gas Usage (million therms)	Electric Savings (aMW)	Additional Gas Usage (million therms)
Single Family	30.6	15.8	9.4	5.0
Multifamily	1.6	1.3	0.5	0.4
Commercial	22.7	17.5	12.3	9.4
Total	54.9	34.6	22.1	14.8

Detailed Resource Potentials

Residential Sector

The fuel conversion potential for single-family homes 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, so those customers are not considered for water heater conversion. In addition, the potential market size for new construction excludes the percentage of customers who have historically included gas systems.

Measures Considered

Cadmus' analysis of fuel conversion considered opportunities for three major end uses in residential dwellings: central heating, water heating, and appliances (clothes dryer and oven).

- For new multifamily buildings, conversion of room (or zonal) heating systems to natural gas furnaces was examined.
- For existing single-family buildings, the cost of converting an existing baseboard system to a central system was not considered, given the high cost of installing the necessary ductwork.

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 measure can result in a 15-percent decrease in energy usage over a standard dryer due to reduced run-time.[13]

Similarly, there are minor differences in the efficiency level of ovens, and an energy savings of 20 percent can be achieved by using a convection oven.[14] Applicable measures and their assumed technical specifications are shown in Table 23. These measures are equivalent to those used for the energy-efficiency analysis, and detailed descriptions can be found in Volume II, Appendix B.

Table 23. End Uses and Measures Assessed

End Use	Gas Measure	Electric Baseline
Space heating	90-percent AFUE condensing furnace	Electric furnace Electric baseboard (new MF only)
Water heating	EF=0.67 storage water heater	Electric water heater
	EF=0.82 tankless water heater	
Appliances	Gas dryer w/ moisture sensor	Electric dryer w/ moisture sensor
	Convection gas range	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. A major factor in determining the cost of new gas service is whether an electric-only customer is on a gas main. For existing single-family customers, data from several sources (including PSE's 2008 REUS) were used to determine availability. In addition, consideration was given to the size range of single family homes, given that larger homes are likely to use more energy for space heating. Homes of 2,000 or fewer square feet were excluded as not meeting the programmatic requirements of sufficient electric usage..

PSE currently provides gas to approximately 49 percent of single-family homes in its electric service area. Customers who currently receive gas service from PSE are considered candidates only for *additional* gas-using equipment, without imposing additional line extension costs. The REUS was used to estimate the total number of gas-heated single-family homes with electric water heater and other appliances. This resulted in an estimate of nearly 24,000 existing gas homes eligible for conversion.

Of the electric customers without PSE gas service, approximately one-third reside in PSE's gas service territory. However, based on the latest data available from PSE, approximately 25 percent of these customers are on a gas main and would be candidates for conversion of all applicable end uses. Off-main customers were excluded from the analysis, as too economically and technically impractical.

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

[13] http://www.consumerenergycenter.org/home/appliances/dryers.html

[14] 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.

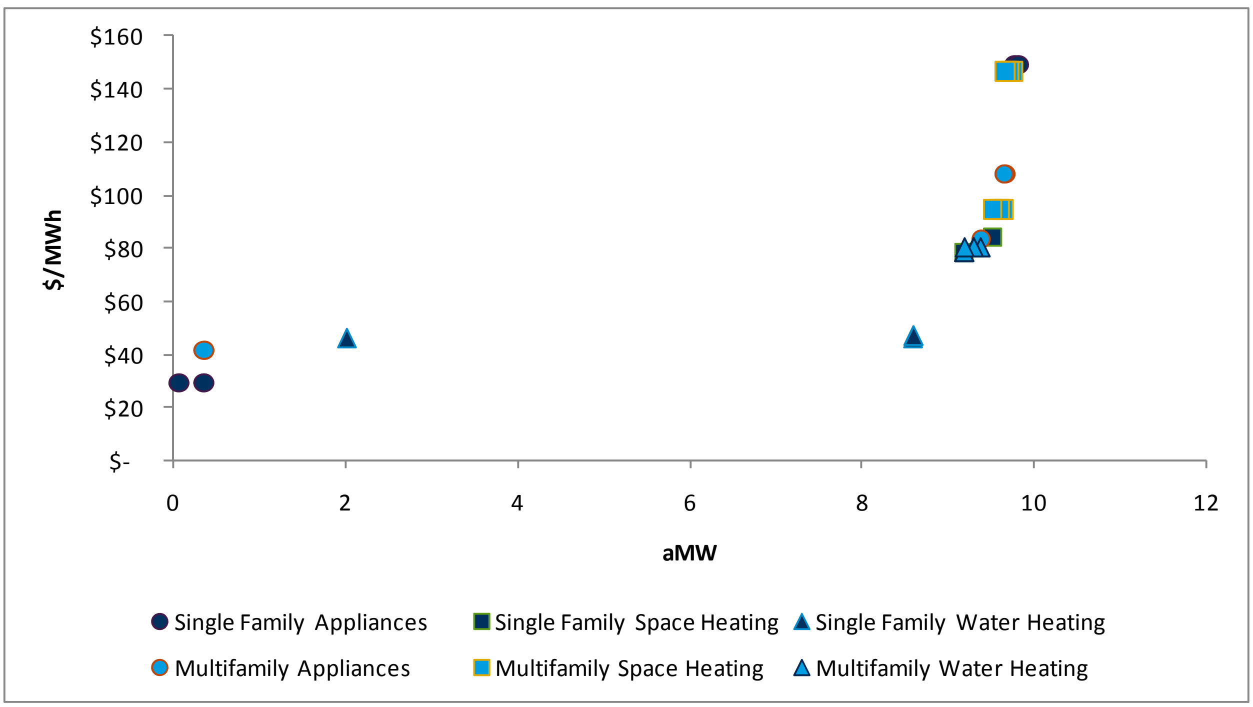
PSE combination territory, a quarter of which are on a main. Of those, approximately 1,200 customers are expected to install a furnace, and another 1,000 customers will install baseboard heating systems.

Conversion Costs and Savings

The total resource cost (TRC) perspective was used to assess conversion costs. This considers the assumed installed cost of the gas measure, less the cost of the equivalent electric measure, and includes gas line extension costs. For electric-only customers, connecting a house to the gas main is assumed to require a service line extension of $3,600. 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 (estimated at $200 per piece of equipment, as determined through interviews with local HVAC contractors on PSE's Contract Referral Service List).

Figure 26 shows how cumulative electric savings categorized by home type and end use are distributed by levelized cost. Conversion savings were estimated based on the same assumed levels of unit energy consumption (UEC) used in the energy-efficiency analysis described in Section 2. Increased gas usage was counted as an ongoing annual O&M cost, and is included in the calculation of levelized cost. For baseline values, electric UECs (kWh/yr) and gas UECs (therms/year) from the baseline forecast for existing single-family and new multifamily homes were used.

Figure 26. Residential Fuel Conversion Supply Curve, Cumulative in 2031



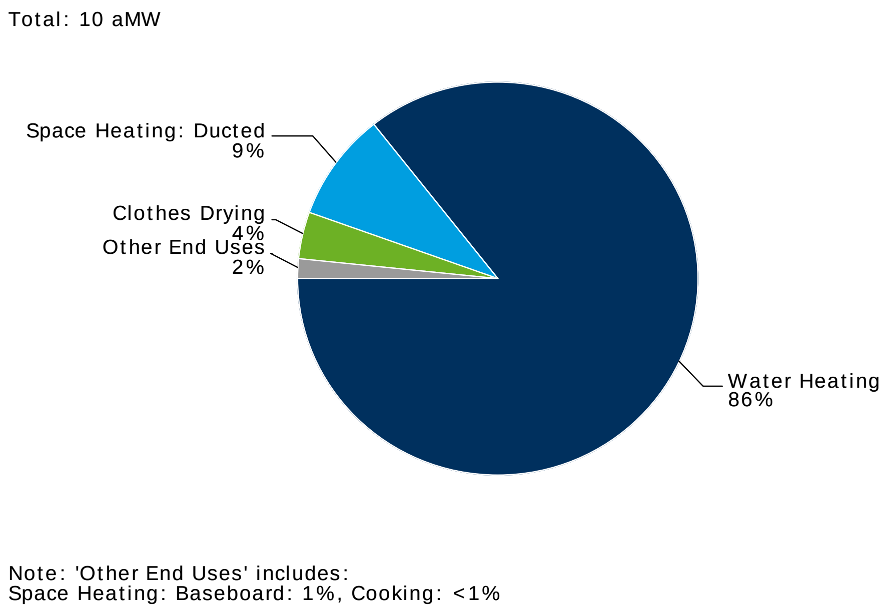
Potential

The technical and achievable technical conversion potential in 2031 for the residential sector by end use are given in Table 24 and Figure 27.

Table 24. Residential Fuel Conversion Potential by End Use, Cumulative aMW in 2031

End Use	Technical Potential	Achievable Technical Potential
Clothes Drying	11.9	0.4
Cooking	2.0	0.1
Space Heating: Baseboard	0.3	0.1
Space Heating: Ducted	2.8	0.9
Water Heating	15.3	8.4
Total	32.3	9.8

Figure 27. Residential Fuel Conversion Achievable Technical Potential by End Use, Cumulative in 2031



Commercial Sector

Conversion of equipment in existing buildings and new facilities was included in the fuel conversion potential for the commercial sector.

Measures Considered

For existing facilities in the commercial sector, the measures considered were 90 percent AFUE furnaces and high-efficiency water heaters (≥0.67 EF storage and tankless). For the new construction segment, the same measures are included, as well as conversion from electric to gas warm-up heaters. Note that it is only the smaller buildings (less than approximately 7,500 square feet) that are likely to utilize a furnace.

Gas Availability

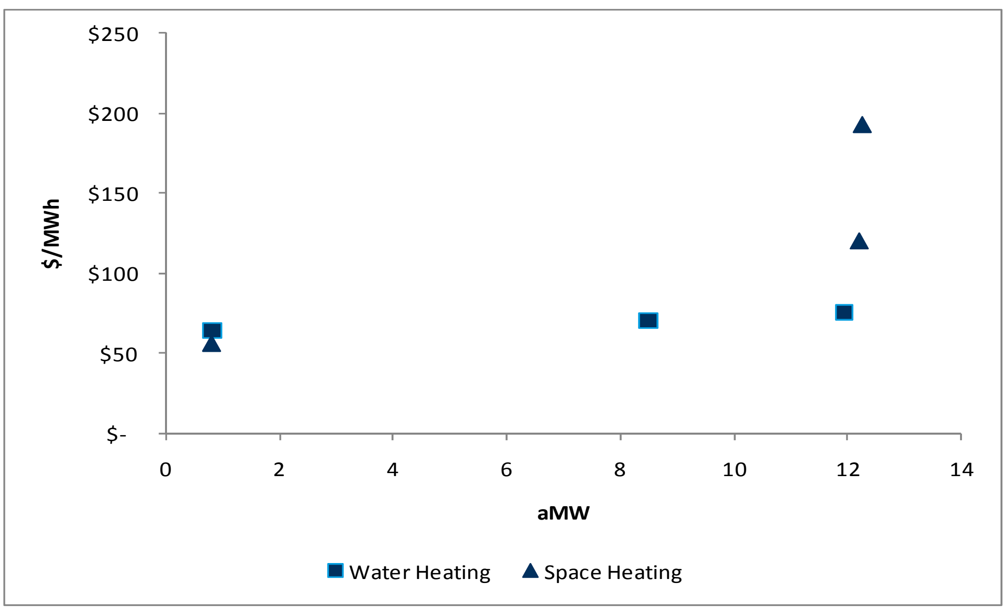
Data from the 2008 Commercial Building Stock Assessment (CBSA), coupled with PSE's nonresidential customer database, provided the market shares by territory and end use. Of existing electric-only customers, approximately 60 percent are in PSE gas territory, and a quarter of those are on a main line. For new customers, approximately 32 percent are expected to be in the combination service territory, a quarter of whom will be on a gas main. By applying this percentage to PSE's commercial new customer forecast and accounting for saturation of furnaces, Cadmus estimates about 400 customers would be eligible over the 20-year study to install a furnace. This number excludes customers who are expected to install a gas line anyway. Additional potential exists for current gas customers who do not already have gas water heaters (approximately 6,500 customers).

Conversion Costs and Benefits

Conversion savings were estimated based on the assumed levels of UEC, consistent with those used in the energy-efficiency analysis described in Section 2. Increased gas usage is counted as an ongoing annual O&M cost, and is counted in the calculation of levelized cost. For baseline values, electric UECs (kWh/yr) and gas UECs (therms/year) from the baseline forecast were used.

Figure 28 shows how cumulative electric savings by end use are distributed by levelized cost. Similar to the residential sector, service-line connection cost is added only to existing customers for the furnace cost. For simplicity, commercial buildings were modeled assuming an energy consumption that was the weighted average of all segments, based on likelihood of equipment being used in the given facility.

Figure 28. Commercial Fuel Conversion Supply Curve, Cumulative in 2031



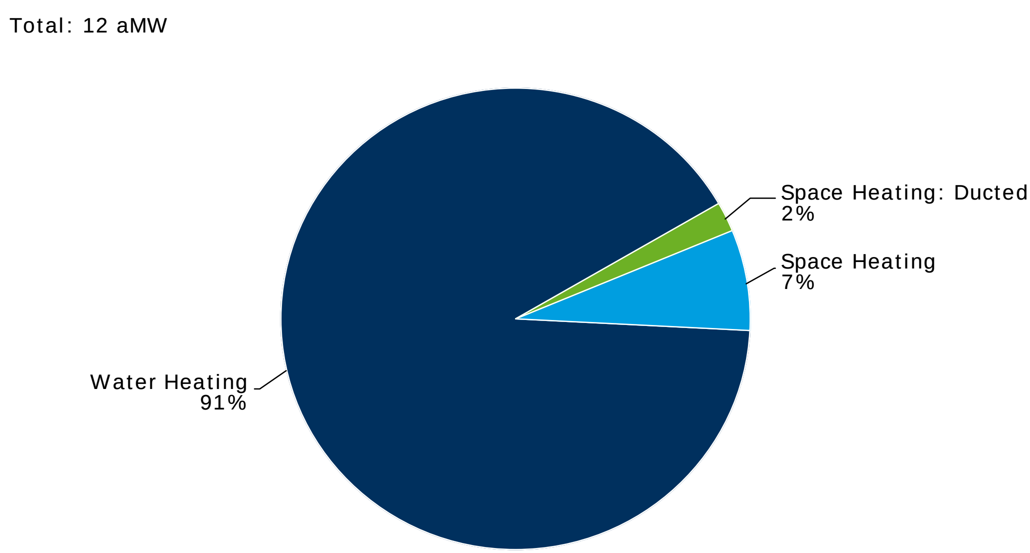
Potential

Table 25 and Figure 29 show the technical and achievable technical conversion potential in 2031 by end use. The end-use "Space Heating: Ducted" represents conversion for electric furnaces in existing buildings, while the "Space Heating" end use represents both furnace and gas warm-up heat conversion in new construction.

Table 25. Commercial Fuel Conversion Potential by End Use, Cumulative aMW in 2031

End Use	Technical Potential	Achievable Technical Potential
Space Heating	1.4	0.9
Space Heating: Ducted	0.4	0.3
Water Heating	21.0	11.1
Total	22.8	12.3

Figure 29. Commercial Fuel Conversion Achievable Technical Potential by End Use, Cumulative in 2031



4. Demand Response Potentials

Scope of Analysis

Focused on reducing a utility's capacity needs, demand-response programs rely on flexible 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 and promote improved system reliability. In some instances, these programs may defer investments in delivery and generation infrastructure.

Demand-response objectives may be met through a broad range of strategies, both price-based (such as time-varying rates or interruptible tariffs) and incentive-based (such as direct load control) strategies. The following demand response strategies are used in this assessment:

1. ***Direct Load Control*** (DLC) programs allow a utility to interrupt or cycle electrical equipment and appliances remotely at a customer's facility. In this study, the assessment of DLC program potential is analyzed for two programs in the residential sector:
    - a combination program of central electric heating (including heat pumps) and electric water heating
    - a combination program of room heating and electric water heating
2. ***Load Curtailment*** programs refer to contractual arrangements between the utility and a third-party aggregator that works with utility customers. The third-party aggregator typically guarantees a specific level of curtailment during an event period, achieving load reduction by working with utility customers who agree to curtail or interrupt their loads in whole or in part when requested. In most cases, participation is required once the customer enrolls in the program and incentives are paid per curtailed kW. Cadmus' analysis of these programs assumes they target nonresidential customers with average monthly loads greater than 100 kW. Customers may use backup generation to meet displaced loads.
3. ***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 time-of-use (TOU) program, with the distinction of more extreme pricing signals during critical events. CPP options are explored for both the residential and commercial sectors in this assessment.

As this study is an update to the 2009 IRP, the program options listed above are based largely on that assessment, with revisions based on input from PSE. After Cadmus completed a review of new demand response literature on the selected programs and on PSE's pilot programs, updates were made to each program. Design specifications and assumptions underlying the analysis for each program strategy are described in detail in this chapter.

Summary of Resource Potentials

Table 26 represents estimated resource potentials for all demand-response strategies for the residential, commercial, and industrial sectors during summer and winter. Achievable technical potential is highest in the residential sector due to the direct load control programs. Note that this analysis does not account for program interactions and overlap; thus, the total technical potential and achievable technical potential estimates may not be fully attainable if all program strategies are implemented.

Table 26. Demand Response Technical and Achievable Technical Potential, MW in 2031

	Winter			Summer		
Sector	Technical Potential	Achievable Technical Potential	Achievable Technical As Percent of System Peak	Technical Potential	Achievable Technical Potential	Achievable Technical As Percent of System Peak
Residential	1,184	110	1.95%	402	32	0.72%
Commercial	767	79	1.40%	783	82	1.85%
Industrial	44	4	0.08%	54	5	0.12%
Total	1,995	193	3.43%	1,239	119	2.68%
*System peak is based on PSE's average load in the top 20 hours for each season.						

Resource Costs and Supply Curves

Applicable resource acquisition costs generally fall into two categories: (1) fixed program expenses such as infrastructure, administration, maintenance, and data acquisition; and (2) variable costs. Variable costs have two categories: those that vary by the number of customers (e.g., hardware costs) and those that vary by kW reduction (primarily incentives).

Where possible, cost estimates were developed for each program option based on comparable programs offered by other utilities. In certain cases, costs at this level of detail were difficult to determine. Many utilities do not report specific program costs, and among those that do there are a wide range of costs.

Development of a new demand-response program can be a significant cost for a utility, requiring enrollment, call centers, program management, load research, development of evaluation protocols, changes to billing systems, and program marketing. Based on the experiences of utilities, this analysis assumed $400,000 as a typical first cost for program development for residential and nonresidential programs.

Marketing costs can vary greatly by utility and program, from about $25 per customer to more than $5,000 per customer, based on interviews with program managers. Cadmus' analysis assumed $25 for each new residential participant and $200 for each commercial or industrial participant.

To develop supply curves, Cadmus calculated streams of projected annual program costs and impacts. These annual figures account for program assumptions such as eligible loads, program participation, participant attrition, and ramp-up time. The levelized cost of each program was then calculated as the ratio of the present value of costs to winter demand savings for comparison with supply-side alternatives. Note that some programs would have additional summer demand savings potential, but these impacts have not been factored into these levelized cost calculations.

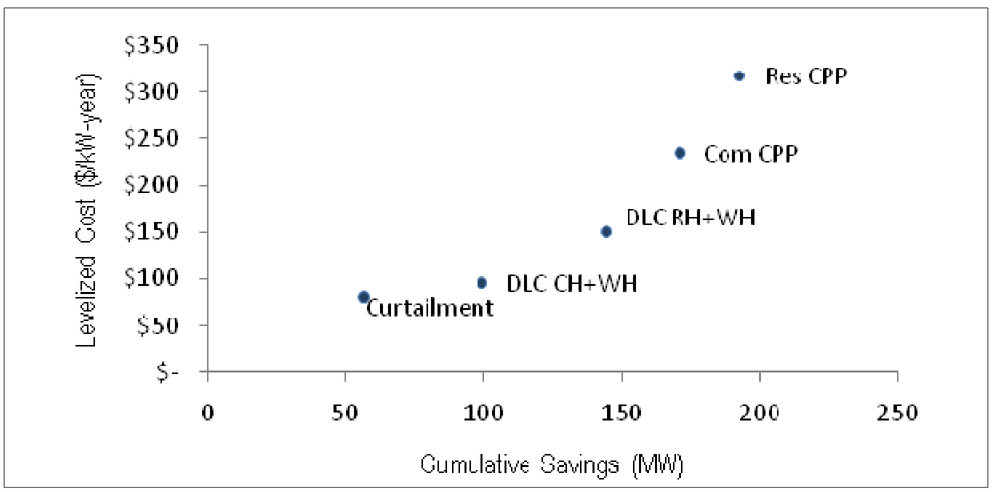
Table 27 displays the per-unit ($/kW per year) costs by program for the estimated achievable technical potential. It is important to note that all programs have higher $/kW costs in the early years due to program start-up costs. The curtailable load program for large nonresidential customers is estimated to be the least-expensive option, having a levelized cost of $81.25/kW per year, while residential CPP was the most costly with a levelized cost of $317/kW per year.

Table 27. Demand Response Achievable Technical Potential and Levelized Costs, Winter MW in 2031

Program Strategy	Achievable Potential	Levelized Cost ($ / Winter kW)
Residential Direct Load Control - Space and Water Heat	43	$95.31
Residential Direct Load Control - Room and Water Heat	45	$150.36
Residential Critical Peak Pricing	22	$316.90
Commercial Critical Peak Pricing	27	$234.48
Commercial Curtailment	56	$81.25

Supply curves were constructed from quantities of estimated achievable technical potential and per-unit costs of each program option. Figure 30 shows the quantity of achievable technical demand-response potential available during winter peak hours in 2031 as a function of levelized cost.

Figure 30. Demand Response Supply Curve, Winter MW in 2031



Resource Acquisition Schedule

Cadmus assumed each program will require an ample start-up period before achieving full participation. Therefore, each program option has an associated ramp rate, as described below:[15]

- The curtailment program is assumed to be the first to begin, achieving approximately 10 MW per year until reaching maximum participation in 2015.

[15] Once programs reach full participation, impacts continue to grow due to forecasted load growth.

- Residential DLC programs start in 2015 as three-year pilot program. In 2018, the programs will slowly begin to grow to full participation by 2022.
- The CPP programs are assumed to start as a three-year pilot 2015 to account for the time required to create a new tariff and put necessary infrastructure in place. In 2018, the programs will begin to ramp up, growing to full deployment by 2020.

Figure 31 and Figure 32 shows the acquisition schedule for achievable potential for winter and summer impacts, respectively.

Figure 31. Demand Response Annual Achievable Technical Potential by Strategy - Winter

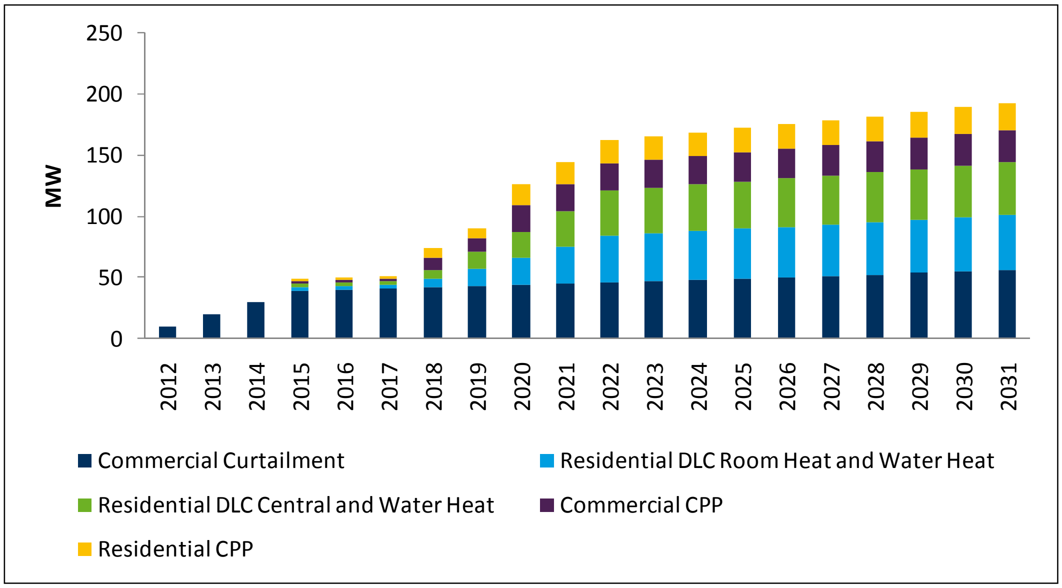
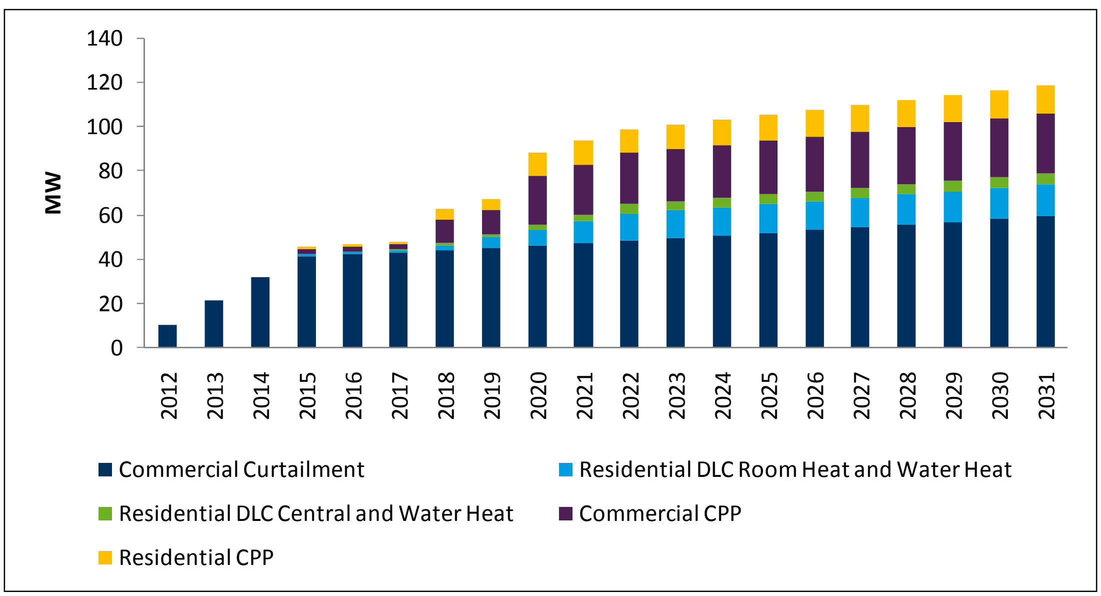


Figure 32. Demand Response Annual Achievable Technical Potential by Strategy – Summer



Detailed Resource Potentials by Program Strategy

Residential Direct Load Control (DLC)

DLC programs are designed to interrupt specific end-use loads at customer facilities through utility-directed control. When deemed necessary, the utility, through a third-party contractor, 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 they typically receive incentives paid through monthly credits on their utility bills.

For this type of program, receiver systems are installed on 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.[16]

Because PSE's system peak occurs in the winter, this assessment focuses on two DLC programs that focus on controlling heating loads. Although residential DLC for air conditioning has been one of the most well-established programs in the nation (utilized by PacifiCorp, MidAmerican Energy, Alliant Energy, Florida Power and Light, Xcel Energy, et al.), the central and room heating DLC programs are a relatively new idea with minimal data available through secondary research.

PSE is currently implementing a space-and-water-heating DLC pilot for 700 homes, with approximately one MW available to be curtailed during each event. Since minimal data are available for these types of programs, some summer DLC program assumptions have been adapted to supplement PSE's pilot data for this assessment.

Central Heating and Water Heating

Table 28 shows the technical and achievable technical potential results by end use by season. Although this is program is primarily focused on reducing the winter peak, water heaters would be available for control in the summer.

Table 28. Residential DLC Central Heat and Water Heat: Technical and Achievable Technical Potential, MW in 2031

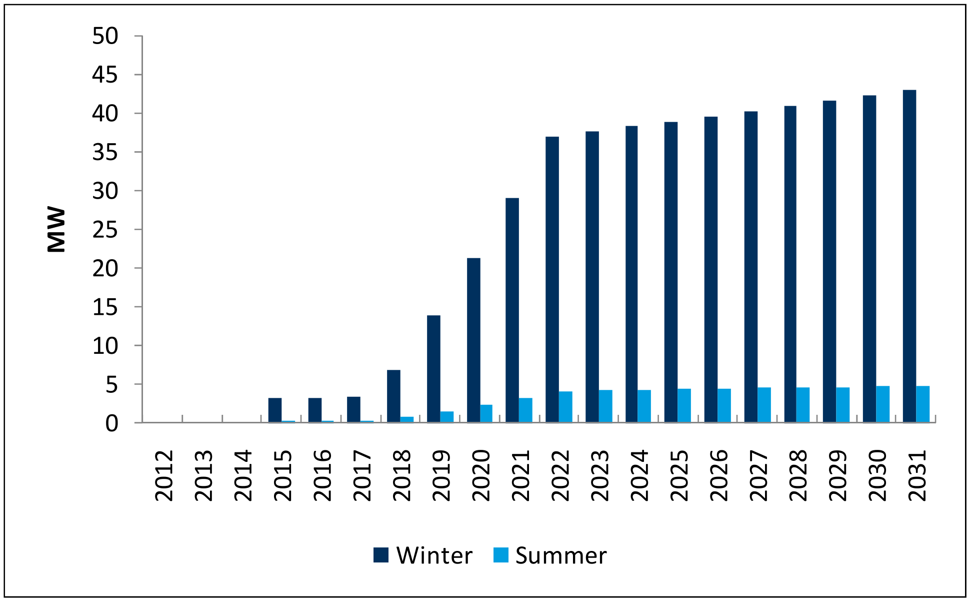
	Winter			Summer		
End Use	Technical Potential	Achievable Technical Potential	Achievable Technical As percent of System Peak	Technical Potential	Achievable Technical Potential	Achievable Technical As percent of System Peak
Central Heat	251	38	0.67%	0	0	0.00%
Water Heat	46	5	0.10%	42	5	0.11%
Total	297	43	0.77%	42	5	0.11%

*System peak is based on PSE's average load in the top 20 hours for each season.

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

Figure 33 shows the achievable potential for the central heat DLC program, based on an acquisition schedule with a three-year pilot program starting in 2015 and ramping up to full participation in 2022.

Figure 33. Residential DLC Central Heat and Water Heat Acquisition Schedule



Utility incentives for residential DLC programs can vary greatly, from a free programmable thermostat, to a set incentive amount per month, to a 15 percent discount on customers' summer electricity bills (which may amount to from $50 to $60 annually for many participants). Incentives for this analysis are set at $32/year for central heat cycling, with an additional $8 for water heating control. Additional costs are assessed for this program, including the following:

- $25 of marketing; per new customer
- $7 for communications per existing customer
- a third-party vendor administrative cost

Detailed assumptions are provided in Table 29 and Table 30.

Table 29. Residential DLC Central Heat and Water Heat: Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	Residential customers in single-family and manufactured homes
End Uses Eligible for Program	Electric central heating (including air-source heat pumps) and electric water heaters
Customer Size Requirements, if any	N/A
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 30. Residential DLC Central Heat and Water Heat: Inputs and Sources

Inputs	Value	Sources or Assumptions
Annual Attrition (%)	5%	Studies found 7% (composed of 5% change-of-service and 2% removals) from utilities, including PacifiCorp, Xcel Energy, Eon US, Sacramento Municipal Utility District,, Florida Power and Light (removals range from 1% to 3%). Removals are accounted for in event participation.
Per Customer Impacts (kW)	1.0 Central Heating 0.6 Water Heating	Based on PSE's central and water heating pilot.
Annual Administrative Costs (percent of annual costs)	5%	An additional utility administrative cost is added to the vendor program cost.
Annual Vendor Administrative Costs (percent of annual costs)	15%	Based on research of vendor bids and informal communication with vendors. Includes maintenance, administrative labor, and dispatch software.
Technology Cost	$160 per switch plus $100 for installation labor	Based on PSE's experience. Assumes the water heater will be controlled by the same switch, consistent with PSE's central heating and water heating pilot program.
Marketing Cost	$25	Assumes 1/2 hour of staff time valued at $50/hour (fully loaded). Based on research of vendor bids and informal communication with vendors.
Incentive (annual costs)	Central Heating $32 Water Heating $8	Incentives range from $30 to $35 for most utilities for one piece of equipment and $8 for additional equipment. Currently PSE's pilot program offers $50 for both central and water heating.
Communication Costs (per Customer Per Year)	$7	This value accounts for annual per-customer communication of a one-way transmission system.
Eligible Load (%)	100%	Assumes all electric central heating customers and associated loads are eligible for the program.
Technical Potential (as percent of Gross)	Central Heating 50% Water Heating 100%	Assumes all central heating units and heat pumps can be retrofit and that the program employs a 50% cycling strategy. Due to the tank, water heaters can be shut off for the entire event (100% reduction).
Program Participation (%)	Single Family and Manufactured Central Heating 20% Multifamily Central Heating 0% Water Heating Single Family: 2%; Multifamily 0%; Manufactured: 5%	Assumes 20% of single-family and manufactured homes with electric central heating will participate. Minimal data for DLC heating programs exist; therefore, this assumption is based on the average participation rate for national programs for DLC cooling programs (between 15% and 20% of all residential customers, which translates to 20% to 30% of eligible customers). This is consistent with the 2009 FERC study[17] estimate of 25% program participation for DLC cooling programs. Due to difficulty in reaching the multifamily segment, these customers have been removed from the potential.. As customers with electric central heating will also include water heating, the water heating participation rates reflect the portion of electric water heaters in homes with electric central heating.
Event Participation (%)	Central Heating 94% Water Heating 94%	Based on utility experience with DLC cooling programs, accounting for homeowners removing units and operational breakdowns (from 2.5% to 5.8%). Because one switch controls both devices, the event participation is the same for both end-uses.

Room Heating and Water Heating

Similar to a central heating DLC program, a room heating DLC program is a relatively new idea with little or no data available through secondary research. Table 31 shows the technical and achievable technical potential results by end use for winter and summer. As with the central heating, there is greater potential in the winter since all the heating load occurs in the winter. The summer portion of the program would only target the water heating load.

[17] Federal Energy Regulatory Commission. "A National Assessment of Demand Response Potential." June 2009.

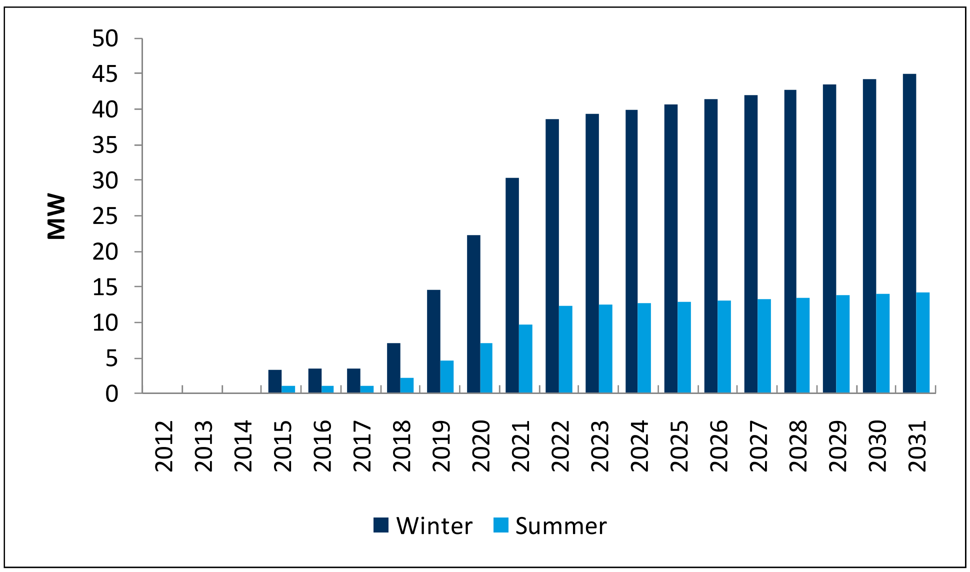
Table 31. Residential DLC Room Heat and Water Heat: Technical and Achievable Technical Potential, MW in 2031

	Winter			Summer		
End Use	Technical Potential	Achievable Technical Potential	Achievable Technical As Percent of System Peak	Technical Potential	Achievable Technical Potential	Achievable Technical As Percent of System Peak
Room Heat	325	29	0.52%	0	0	0.00%
Water Heat	103	16	0.28%	93	14	0.32%
Total	428	45	0.80%	93	14	0.32%

*System peak is based on PSE's average load in the top 20 hours for each season.

Figure 34 shows the achievable potential for the central heat DLC program based on an acquisition schedule starting in 2015, with a three-year pilot program, ramping up to full participation in 2022.

Figure 34. Residential DLC Room Heat and Water Heat Acquisition Schedule



All cost assumptions, except for technology costs, are consistent with the central heating program. Detailed assumptions are provided in Table 32 and Table 33.

Table 32. Residential DLC Room Heat and Water Heat: Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	All residential
End Uses Eligible for Program	Electric room heating (baseboard)
Customer Size Requirements, if any	N/A
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 33. Residential DLC Room Heat and Water Heat: Inputs and Sources

Inputs	Value	Sources or Assumptions
Annual Attrition (%)	5%	Studies have found 7% (composed of 5 % change-of-service and 2% removals) from utilities, including PacifiCorp, Xcel Energy, Eon US, Sacramento Municipal Utility District,, Florida Power and Light (removals range from 1 to 3%). Removals are accounted for in event participation.
Per Customer Impacts (kW)	0.75 Room Heating 0.6 Water Heating	Assumes approximately 25% lower demand savings than the central heating program, based on engineering estimate. Water heating savings are based on PSE's pilot program.
Annual Administrative Costs (percent of annual costs)	5%	An additional utility administrative cost is added to the vendor program cost.
Annual Vendor Administrative Costs (percent of annual costs)	15%	Based on research of vendor bids and informal communication with vendors. Includes maintenance, administrative labor, and dispatch software.
Technology Cost	$160 per switch plus $250 for installation labor	Assumes one switch will control all room heaters and the water heater. Switch costs are based on PSE's experience. Installation cost is $250 (assumes 25 percent labor cost savings per heater).
Marketing Cost	$25	Marketing costs are based on 1/2 hour of staff time valued at $50/hour (fully loaded).
Incentive (annual costs)	Room Heating $32 Water Heating $8	Incentives range from $30 to $35 for most utilities for one piece of equipment and $8 for additional equipment. Currently PSE's pilot program offers $50 for both space and water heating.
Technical Potential (as percent of Gross)	Room Heating 50% Water Heating 100%	Assumes all room units can be retrofit and that the program employs a 50 percent cycling strategy. Due to the tank, water heating can be shut off for the entire event (100 percent reduction).
Program Participation (%)	Single Family and Manufactured Room Heating 15% Multifamily Room Heating 0% Water Heating Single Family: 5%; Multifamily 11%; Manufactured: 3%	Assumes 15% of customers with electric room heating will participate. Minimal data for DLC heating programs exists; therefore, the assumption is based on the average participation rate for national programs for DLC AC programs (between 15% and 20% of all residential customers, which translates to 20% to 30% of eligible customers). Due to the difficulty of reaching the multifamily segment, it is assumed that multifamily customers will only participate in the water heating portion of this program. All customers with electric room heating will also include water heating in the program, so participation rates have been adjusted to account for the percent of electric heating customer with electric water heat.
Event Participation (%)	Room Heating 94% Water Heating 94%	Based on PacifiCorp's Cool Keeper historic event participation, which accounts for homeowners removing units and operational breakdowns (2.5% to 5.8%). Because one switch controls both devices, the event participation is the same for both end-uses.
Annual Attrition (%)	5%	Based on utility experience with DLC cooling programs, accounting for homeowners removing units and operational breakdowns (2.5% to 5.8%). Because one switch controls both devices, the event participation is the same for both end-uses.

Nonresidential Load Curtailment

Load curtailment programs utilize contractual arrangements between the utility, a third-party aggregator that implements the program, and utility 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 each contract.

Customers are generally not paid for individual events, but are compensated in the form of a fixed monthly amount per kW of pledged curtailable load or in the form of a rate discount. Typically, contracts require customers to curtail their connected load by either a set percentage (typically, from 15 percent to 20 percent) or a predetermined level (e.g., 100 kW). These types of 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.

For this study, Cadmus assumed nonresidential customers with a monthly demand of at least 100 kW would be eligible for such a program. One key aspect to the potential savings associated with the curtailment 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, and these customers are included in this assessment.

Table 34 shows the estimated technical and achievable technical potential by sector for winter and summer. These potentials are inclusive of the approximate five MW PSE has under control through its curtailment pilot program.

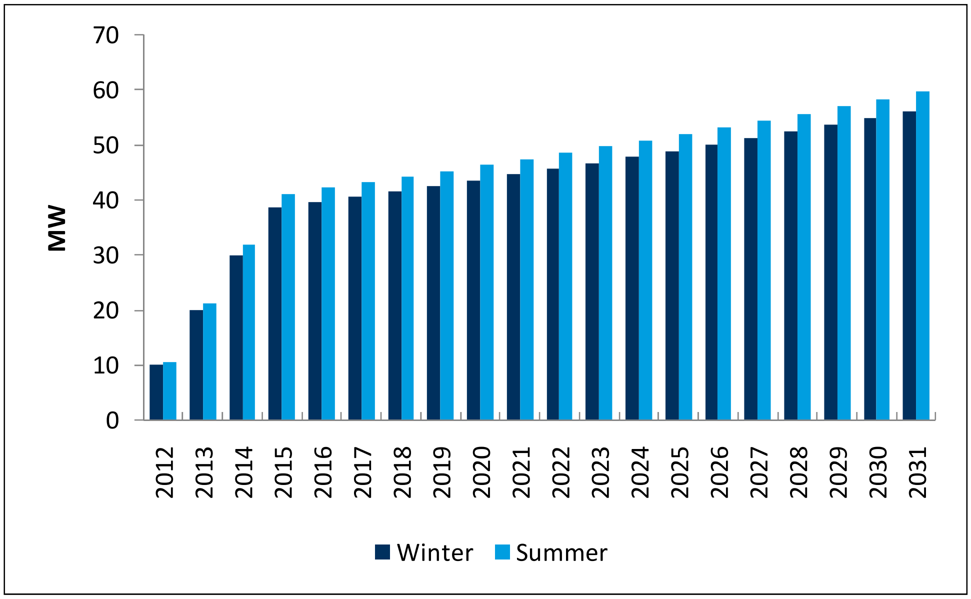
Table 34. Load Curtailment Technical and Achievable Technical Potential, MW in 2031

	Winter			Summer		
Sector	Technical Potential	Achievable Technical Potential	Achievable Technical As percent of System Peak	Technical Potential	Achievable Technical Potential	Achievable Technical As percent of System Peak
Commercial	383	55	0.98%	391	58	1.31%
Industrial	22	1	0.02%	27	2	0.03%
Total	406	56	1.00%	418	60	1.35%

*System peak is based on PSE's average load in the top 20 hours for each season.

Figure 35 shows the achievable potential for the curtailment program based on an acquisition schedule that begins in 2012, achieving approximately 10 winter MW per year until full potential is reached in 2015.

Figure 35. Load Curtailment Acquisition Schedule



Curtailment programs are typically run through third-party aggregators that charge a set $/kW cost. For this assessment, the technology costs and marketing costs were excluded from the bid when calculating the total $/kW cost of the program. Detailed assumptions providing values and sources that derived potential and levelized costs are shown in Table 35 and Table 36.

Table 35. Load Curtailment Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	All industrial and commercial market segments
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	Customers >100kW
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 36. Load Curtailment Inputs Consistent Across Market Segments

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	5%	Administrative costs are rolled into the $/kW cost
Technology Cost (per new participant)	$1,400	Technology costs include communications, connectivity and meters, if necessary, based on California spending of $32m for 23,000 large C&I hardware after energy crisis
Marketing Cost (per new participant)	$200	Assumes 4 hours of utility labor at $50/hour (fully loaded)
Incentives (annual costs per participating kW)	N/A	Included in third-party aggregator bid
Overhead: First Costs	N/A	Included in third-party aggregator bid
Vendor Costs	$80	Based on third-party aggregator bid (exclusive of technology and marketing costs)
Technical Potential	Varies by Sector	Based on detailed engineering audits of demand response potential of commercial and industrial 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 (%)	Varies by Sector	Based on survey of PacifiCorp nonresidential customers. See Table 37 for details.
Event Participation (%)	95%	Based on informal conversations with a third-party aggregator.

Table 37. Load Curtailment Inputs and Sources Varying by Segment

Market Segment	End Use	Technical Potential as percent of Load Basis	Program Participation
Grocery	Segment Total	5%	13%
Hospital	Segment Total	12%	0%
Office	Segment Total	16%	21%
Dry Goods Retail	Segment Total	16%	8%
Hotel-Motel	Segment Total	17%	0%
Other	Segment Total	16%	13%
Restaurant	Segment Total	17%	25%
School	Segment Total	17%	23%
University	Segment Total	17%	23%
Warehouse	Segment Total	16%	13%
Industrial	Segment Total	17%	6%

Critical Peak Pricing (CPP)

Under a CPP program, customers receive a discount on their retail rates during non-critical 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 the 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-, off-, and mid-peak prices by season). During CPP events, the normal peak price under a TOU rate structure is replaced with a much higher price, generally set to reflect the utility's avoided cost of supply during peak periods.

CPP rates only take effect a limited number of times during the year. 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 shed or shift load. Most CPP programs provide advanced notice in addition to event criteria (such as a threshold for forecasted weather temperatures) to help customers plan their operations. One attractive feature of the CPP program is the absence of a mandatory curtailment requirement.

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

- Customers under CPP rates are often equipped with automated controls triggered by a signal from the utility
- The higher CPP rate serves as an incentive for customers to shift load away during the CPP event period
- 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, this 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 vary widely by utility and by program, with some utilities reserving the right to call an event at any time while others must provide notice one day before the event. This analysis assumes that approximately 10 four-hour events will be called during the summer and winter for a total of 40 event hours.

Currently, peak pricing is 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 in Eastern states.

Table 38 shows the estimated technical and achievable technical potential by sector for winter and summer.

Table 38. CPP Technical and Achievable Technical Potential, MW in 2031

	Winter			Summer		
Sector	Technical Potential	Achievable Technical Potential	Achievable Technical As percent of System Peak	Technical Potential	Achievable Technical Potential	Achievable Technical As percent of System Peak
Residential	458	22	0.39%	267	13	0.29%
Commercial	383	24	0.42%	391	24	0.54%
Industrial	22	3	0.05%	27	4	0.08%
Total	863	48	0.86%	685	40	0.90%

*System peak is based on PSE's average load in the top 20 hours for each season.

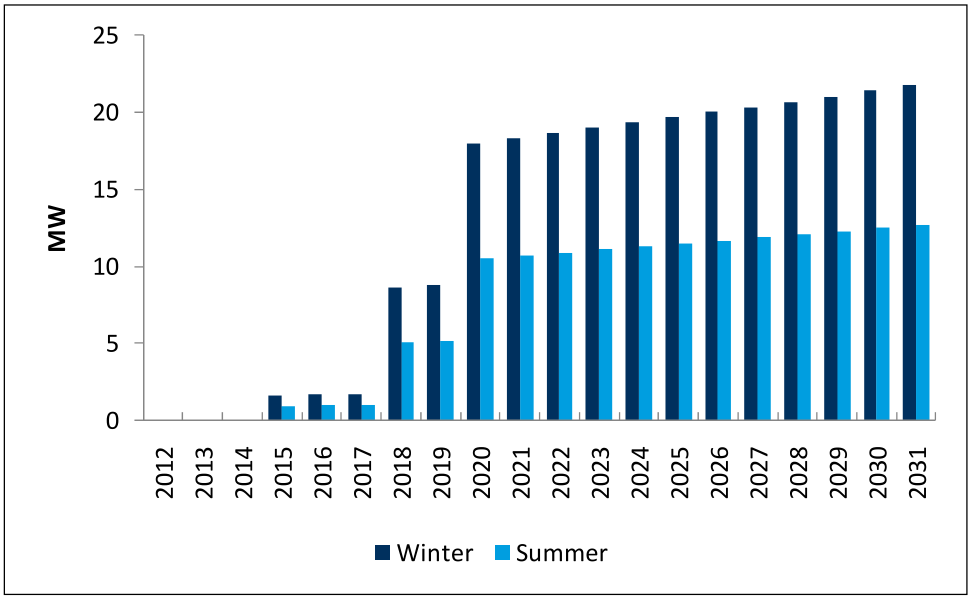
Residential CPP

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 (such as critical peak, on-peak, or off-peak). This combination of pricing and technology has shown to be an effective means of improving per-customer load impacts.

Technically, national studies have shown that 13 percent to 40 percent[18] of peak demand can be reduced for participating customers. Cadmus' study assumes a 15-percent reduction based on the California pricing pilot and PSE's experience with the nonresidential curtailable load pilot. Five percent is consistent with the 2009 FERC study, and event participation is estimated to be 95 percent, based on almost all participants shifting consumption during a CPP event.

Figure 36 shows the achievable technical potential for the nonresidential CPP program, based on an acquisition schedule that begins with a three-year pilot program in 2015 to account for the time necessary to create a new tariff and put infrastructure in place. This is expected to be followed by two years of increased participation, reaching full participation in 2020.

Figure 36. Residential CPP Acquisition Schedule



The residential CPP program has a start-up cost of $400,000, since a new rate structure will be put in place. Additionally, the program will require the installation of a smart thermostat and meter and ongoing communication, priced at $515 and $7 per participant, respectively.

[18] 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.

Marketing costs are consistent with other program assumptions, and no incentives are given because the program is rate-based. Detailed assumptions of values and sources that derived the potential and levelized costs are shown in Tables 39 and 40.

Table 39. Residential CPP Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	All residential customers
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	N/A
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 40. Residential CPP Inputs and Sources

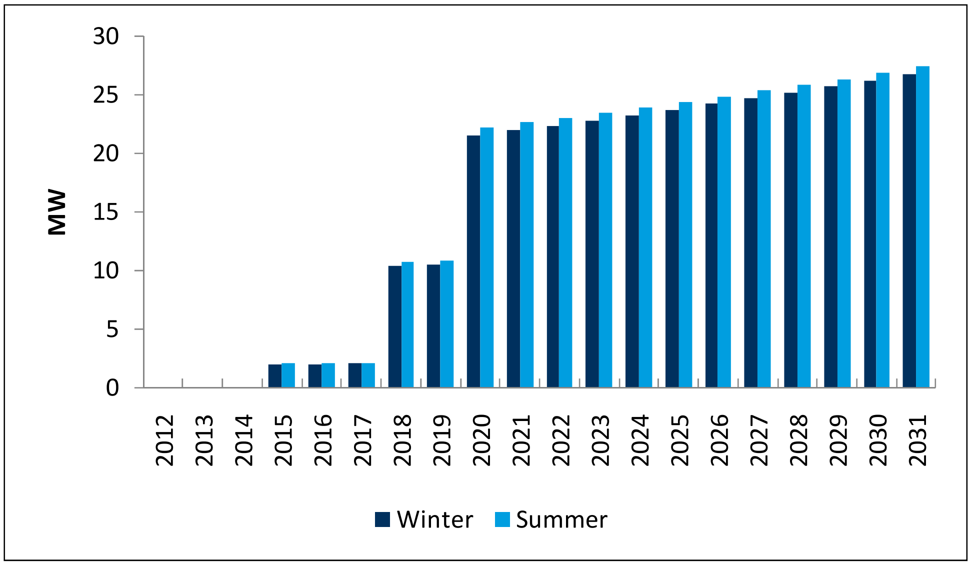
Inputs	Value	Sources or Assumptions
Annual Attrition	5%	Accounts for 5%change of service.
Annual Administrative Costs (%)	15%	Assumes administrative adder of 15%
Technology Cost (per new participant)	$515	Smart Thermostat: $200 installation and $315 for the meter, based on $150 for the installed cost of radio frequency devices (CEC 2004 report) plus an additional $150 to upgrade to AMI and $15/customer communication charge.
Marketing Cost (per new participant)	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual costs per participant)	N/A	There are no customer incentives, but customers may have a lower bill than they would have on a standard rate.
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	Standard program development assumption, including necessary internal labor, research, and IT/billing system changes
Eligible Load (%)	100%	All residential customers are eligible.
Technical Potential	15%	An average statewide reduction of 27% was found for the California residential pilot CPP programs implemented in the summer (Charles River Associates, 2005). PSE's experience with a C&I pilot shows that winter events save about 50% less than summer events and, therefore, event participation was reduced to 15%.
Program Participation (%)	5%	Gulf Power 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.) Gulf Power expects 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.) 2009 FERC study reports a 5% maximum participation rate.
Event Participation (%)	95%	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: Comverge). With two-way communications (through AMI or Zigbee gateway for example) utilities can identify and replace malfunctioning thermostats, so event participation is much higher than in old one-way, switch-based DLC programs.

Nonresidential CPP

Cadmus has identified very few nonresidential CPP programs for medium-to-large customers; therefore, this analysis relies on engineering audit assumptions for technical potential estimates, which are consistent with CPP studies showing an average of 8 percent savings.[19] Event participation of 56 percent is based on the 2006 California C&I Pilot,[20] and it accounts for the higher rate of opt-outs expected for commercial customers.

Figure 37 shows the achievable technical potential for the nonresidential CPP program based on an acquisition schedule that begins with a three-year pilot program in 2015, accounting for the time needed to create a new tariff and put infrastructure in place. This is expected to be followed by two years of increased participation, reaching full participation in 2020.

Figure 37. Nonresidential CPP Acquisition Schedule



The nonresidential CPP program will also have a start-up cost of $400,000, since a new rate structure will be put in place. Additionally, the program will require the installation of metering and communication equipment (priced at $1,400) and ongoing communication costs of $7 per participant, respectively. Marketing costs are consistent with other program assumptions, and no incentives are given because the program is rate-based. Detailed assumptions for the nonresidential CPP program are shown in Tables 41 and 43.

19 LBNL Fully Automated CPP study, 2006.

20 Hopper, Nicole and Charles Goldman. The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response. 2007.

Table 41. Nonresidential CPP Program Basics

Program Concept	Assumptions
Customer Sectors Eligible	All nonresidential market segments
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	Nonresidential customers with monthly load greater than 100 kW
Winter Load Basis	Top 20 hours
Summer Load Basis	Top 20 hours

Table 42. Nonresidential CPP Inputs and Sources not Varying by Sector or Segment

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	15%	Assumes administrative adder of 15%
Technology Cost (per new participant)	$1,400	Technology costs include communications, connectivity and meters, if necessary, based on California spending of $32 million for hardware for 23,000 large C&I after energy crisis
Marketing Cost (per new participant)	$200	Assumes 4 hours of utility labor at $50/hour (fully-loaded) for account representatives.
Marketing Cost (first year)	$150,000	Assumes an additional one time FTE cost to implement the program.
Communication Costs (per Customer Per Year)	$7	This value accounts for annual per-customer communication of a one-way transmission system.
Incentives (annual costs per participant)	N/A	There are no customer incentives, but customers may have a lower bill than they would have on a standard rate.
Overhead: First Costs	$400,000	Standard program development assumption, including necessary internal labor, research and IT/billing system changes
Technical Potential as percent of Load Basis	Varies by Sector	Based on detailed engineering audits of demand response potential for commercial and industrial customers throughout California, with third-party verification of results. Studies of CPP results show that 8% was saved on average (LBNL Fully Automated CPP study, 2006), which is comparable to taking this technical potential and the event participation combined.
Program Participation (%)	Varies by Sector	Based on survey of PacifiCorp nonresidential customers. See Table 37 for details.
Event Participation (%)	56%	Based on 2006 California C&I results for CPP Pilot

Table 43. Nonresidential CPP Inputs and Sources Varying by Sector or Segment

Market Segment	End Use	Technical Potential as percent of Load Basis	Program Participation
Grocery	Segment Total	5%	12%
Hospital	Segment Total	12%	0%
Office	Segment Total	16%	8%
Dry Goods Retail	Segment Total	16%	16%
Hotel-Motel	Segment Total	17%	0%
Other	Segment Total	16%	12%
Restaurant	Segment Total	17%	25%
School	Segment Total	17%	18%
University	Segment Total	17%	18%
Warehouse	Segment Total	16%	12%
Chemical Manufacturing	Segment Total	17%	24%
Computer Electronic Manufacturing	Segment Total	17%	24%
Electrical Equipment Manufacturing	Segment Total	17%	24%
Fabricated Metal Products	Segment Total	17%	24%
Food Manufacturing	Segment Total	18%	24%
Industrial Machinery	Segment Total	17%	24%
Miscellaneous Manufacturing	Segment Total	17%	24%
Nonmetallic Mineral Products	Segment Total	17%	24%
Paper Manufacturing	Segment Total	17%	24%
Petroleum Refining	Segment Total	17%	0%
Plastic Rubber Products	Segment Total	17%	24%
Primary Metal Manufacturing	Segment Total	17%	24%
Printed Related Support	Segment Total	17%	24%
Transportation Equipment Manufacturing	Segment Total	17%	24%
Wastewater	Segment Total	17%	24%
Water	Segment Total	17%	24%