Final Report – Volume I

Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources

Prepared for PacifiCorp

July 11, 2007

In collaboration with Summit Blue Consulting and Nexant, Inc.

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Table of Contents: Volume I

Tables and Figures

Table of Contents: Volume II

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Executive Summary

Overview

For nearly 25 years, PacifiCorp has been actively engaged in the design and delivery of demand-side management (DSM) products and services. Beginning with its management and sponsorship of the Hood River Conservation Project in the early 1980s, PacifiCorp has continued to be an innovator in energy efficiency and has conceived and implemented programs such as Energy FinAnswer, which, in its class, is considered one of the best programs in North America. Over the last 15 years, PacifiCorp has invested approximately $345 million on DSM programs, offsetting nearly 2,700 GWh of energy – the equivalent of nearly 515 MW of capacity annually, assuming a 60% load factor on average.[1] Currently, PacifiCorp operates successful capacity-focused programs for irrigation load curtailment, demand buyback, and air conditioning direct load control, which together helped reduce PacifiCorp's peak loads by 149 MW in 2006. PacifiCorp also has an additional 260 MW available for control under interruptible agreements with a select group of its largest commercial and industrial customers.

Beginning in the early 1990s, PacifiCorp developed biennial integrated resource plans (IRPs) to identify the optimal, least-cost mix of supply and demand-side options to meet its projected long-run resource requirements. This report summarizes the results of an independent study to conduct a comprehensive, multi-sector assessment of the long-run potential for DSM resources in PacifiCorp's Pacific Power (Oregon,[2] Washington, and California) and Rocky Mountain Power (Idaho, Wyoming, and Utah) service territories to support the PacifiCorp's integrated resource planning process and help further PacifiCorp's active pursuit of DSM resources.

This study's principal goal is to develop reliable estimates of the magnitude, timing, and costs of alternative DSM resources, comprised of capacity-focused program options (defined throughout this report as Class 1 and Class 3 DSM resources), energy-efficiency products and services (defined as Class 2 DSM resources), and other "supplemental" resources such as solar, combined heat and power, and dispatchable standby generation. The analysis of resource potential in this study are augmented by an examination of the benefits of consumer awareness and education initiatives (Class 4 DSM resources) and an analysis of how future structural changes, such as technological innovation, macroeconomic conditions, and public policy, might affect the findings and conclusions of this study.

The main emphasis of this study has been on resources with sufficient reliability characteristics, which are expected to be technically feasible (technical potential), cost-effective (economic potential), and realistically achievable (achievable potential) during the 20-year planning horizon. For Class 2 DSM (energy-efficiency) resources, the methods used to evaluate the

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1 Expenditures and savings include PacifiCorp's contributions to the Energy Trust of Oregon and the associated energy savings generated by those funds. All savings and capacity information calculated at generator.

2 Since the Energy Trust of Oregon is responsible for the planning and delivery of Class 2 DSM resources in Oregon, potential for these resources are exclusive of Oregon.

technical potential and cost-effectiveness draw upon practices standard in the utility industry and used by other planning bodies within PacifiCorp's service territories, including the Northwest Power and Conservation Council in its assessment of regional energy-efficiency potential in the Northwest. Potential for capacity-focused resources (Class 1 and Class 3 DSM) and supplemental resources is calculated using a similar methodology, with one exception. In these cases, expected market acceptance rates, based on customer surveys (Class 1 and Class 3 DSM) and prevailing trends in the U.S. (supplemental resources), are applied to technical potential to develop estimates of "market potential" before estimating levelized costs and applying an economic screen. In the case of supplemental resources, the economic and achievable potential are assumed the same.

Summary of the Results

This study's results indicate a cumulative, system-wide, *technical* energy-focused potential of 9,258 average megawatts (aMW)[3] of electricity over the 20-year planning horizon from 2008 to 2027 (Table ES-1). Approximately 1,049 aMW of the identified technical potential is expected to be cost-effective, based on the total resource cost (TRC) criterion, and 639 aMW are assumed reasonably achievable once normal market and program delivery constraints are accounted for. Energy-efficiency (Class 2 DSM) resources account for 79% (502 aMW), and supplemental resources (including on-site solar and combined heat and power) account for the remaining 21% (137 aMW) of the achievable energy-efficiency potential. These results represent the savings measured at generation; therefore, they account for appropriate transmission and distribution losses.

Table ES-1. Energy-Focused Resource Potential (aMW in 2027): Technical, Economic, and Achievable by Resource and Service Territory

Resource Class/Service Territory	Technical Potential	Economic Potential	Achievable Potential
Rocky Mountain Power			
Class 2 DSM Resource	981	798	440
Supplemental Resource	5,643	90	90
Pacific Power			
Class 2 DSM Resource*	149	114	62
Supplemental Resource	2,485	47	47
PacifiCorp System	**9,258**	**1,049**	**639**

* Excludes Oregon.

Note: Individual results may not sum to total due to rounding.

[3] Average megawatt (aMW) is a unit of energy used for planning purposes in the Pacific Northwest. It is calculated as the ratio of energy (MWh) and the number of hours in the year (8760).

The DSM and supplemental resources identified in this study are also expected to reduce PacifiCorp's system peak demand (defined as the 40 highest load hours during summer)[4] by approximately 1,601 MW. Over 50% (835 MW) of this reduction is owed to the peak-coincident impacts of energy-efficiency gains from the implementation of Class 2 DSM resources. Achievable capacity-focused resources in Class 1 and Class 3 DSM account for 30% (476 MW) of the achievable peak demand reduction potential (Table ES-2). Supplemental resources provide an additional 290 MW, approximately half of which (136 MW) are derived from the capacity-focused supplemental resource option (dispatchable standby generation); and the remainder are derived from peak-coincident impacts of energy-focused supplemental resources, namely combined heat and power.

Table ES-2. Peak Demand Reduction Potential (MW in 2027): Technical, Economic, and Achievable by Resource and Service Territory

Resource Class/Service Territory	Technical Potential	Economic Potential	Achievable Potential
Rocky Mountain Power			
Class 1 DSM Resource	1,700	1,300	265
Class 2 DSM Resource	2,042	1,348	752
Class 3 DSM Resource	2,811	2,715	170
Supplemental Resource	3,510	211	211
Pacific Power			
Class 1 DSM Resource	513	108	20
Class 2 DSM Resource*	236	141	83
Class 3 DSM Resource	1,016	410	21
Supplemental Resource	1,371	79	79
PacifiCorp System	**13,198**	**6,312**	**1,601**

* Excludes Oregon.
Note: Individual results may not sum to total due to rounding.

Because the study excludes an assessment of Oregon's energy-efficiency potential, the Rocky Mountain service territory accounts for a disproportionately larger share of total energy-focused resources (83%) and more than 87% of system peak demand reductions (Figure ES-1 and Figure ES-2).

[4] The top 40 hours are defined independently for the Rocky Mountain Power and Pacific Power service territories.

Figure ES-1. Achievable DSM Potential by Resource Type (MW and aMW 2027)
(Rocky Mountain Power Territory)

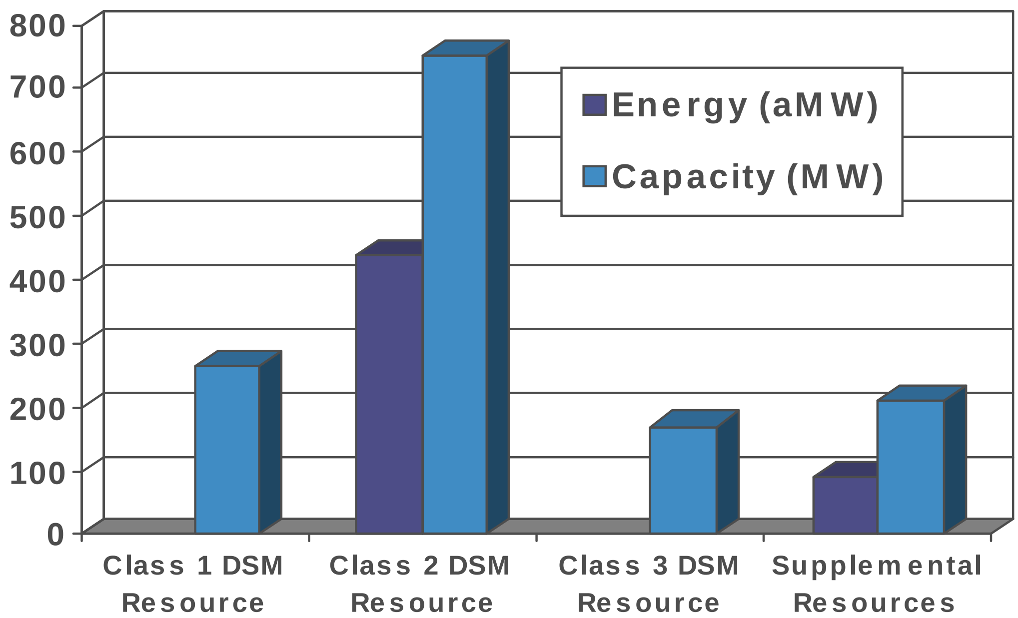
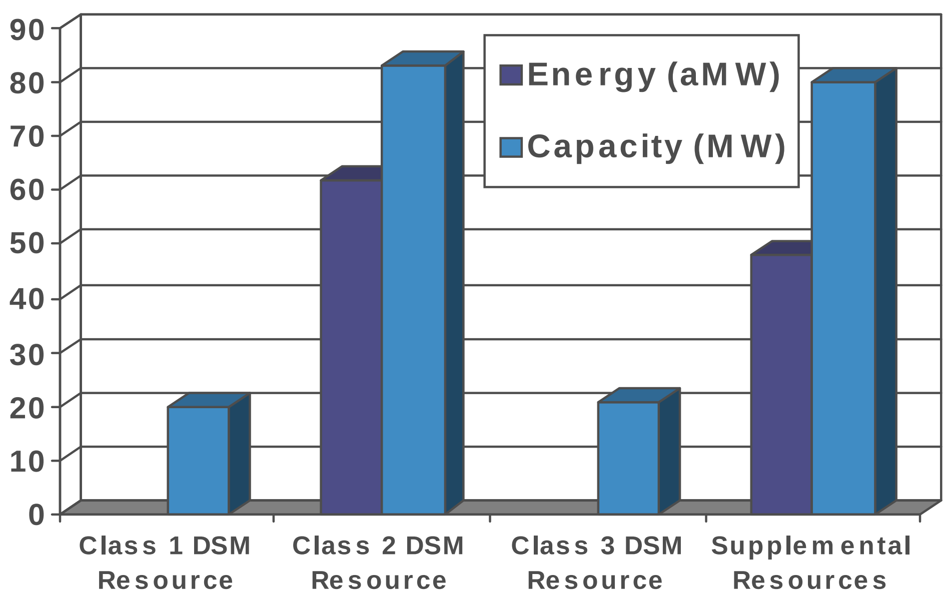


Figure ES-2. Achievable DSM Potential by Resource Type (2027)
(Pacific Power Territory, Excluding Oregon for Class 2 DSM)



Capacity-Focused (Class 1 and Class 3 DSM) Resources

Demand-side resource options that focus on reducing capacity fall into the categories of "firm" (Class 1 DSM) and "non-firm" (Class 3 DSM) resources. Three capacity-focused options in Class 1 DSM (direct load control, irrigation load curtailment, and thermal energy storage) and five options in Class 3 DSM (curtailable tariffs, demand buyback, time-of use rates, critical peak pricing, and real-time pricing) are analyzed in this study. The results of the analyses indicate the greatest opportunities for Class 1 DSM resources are likely to be in direct load control of air conditioning equipment in the residential sector and irrigation load curtailment. In Class 3 DSM, large contributors to peak load reduction opportunities are critical peak pricing across sectors and curtailable tariffs in the commercial and industrial (C&I) sectors (Table ES-3).

The combined impacts of capacity-focused resources may be expected to reduce PacifiCorp's 2027 peak capacity requirements by 4% (Table ES-3). To account for the interaction between energy-efficiency and capacity-focused program options, 2027 peak demand impact is calculated assuming all energy-efficiency achievable potential is implemented. To avoid double counting, the estimates of achievable potential for Class 3 DSM resources assume eligible customers cannot participate in more than one program option simultaneously. The results in Table ES-3 are inclusive of the quantity of reduction under contract for the irrigation sector, direct load control of air conditioning (Cool Keeper), and demand buyback (Energy Exchange) as of the writing of this report.

Table ES-3. Achievable Class 1 and Class 3 (Capacity-focused) DSM Resource Potential by Customer Sector and Service Territory (MW in 2027)

	Rocky Mountain		Pacific Power		PacifiCorp System	
	Achievable Potential	% of 2027 Peak	Achievable Potential	% of 2027 Peak	Achievable Potential*	% of 2027 Peak*
Class 1 DSM- "Firm"						
Residential	160	8%	- - -	- - -	160	1%
Commercial	1	0%	- - -	- - -	1	0%
Industrial	- - -	- - -	- - -	- - -	- - -	0%
Irrigation	104	21%	20	8%	125	1%
Class 3 DSM- "Non-Firm"						
Residential	28	1%	- - -	- - -	28	0%
Commercial	45	1%	15	1%	60	0%
Industrial	96	4%	6	3%	102	1%
Irrigation	- - -	- - -	- - -	- - -	- - -	0%
Total	**434**	**5%**	**41**	**1%**	**476**	**4%**

* Results are approximate; Rocky Mountain Power and Pacific Power top load hours are defined differently.

Note: Individual results may not sum to total due to rounding.

Energy-Efficiency (Class 2 DSM) Resources

As shown above in Table ES-1, the system-wide technical potential for energy-efficiency resources (Class 2 DSM) is estimated at 1,130 aMW, 80% of which (913 aMW) pass the TRC cost-effectiveness screen. Based on interviews with a representative sample of PacifiCorp C&I customers and surveys of nationally-recognized DSM professionals (utility and others), an estimated 502 aMW (nearly 55%) of cost-effective energy-efficiency resources are likely to be achievable (Table ES-4). Approximately 27 aMW of achievable energy-efficiency potential (5% of total) are expected to originate from emerging technologies. Assuming equal annual increments of 25 aMW over twenty years, the achievable Class 2 DSM resources represent an additional 10 aMW above PacifiCorp's current rate of approximately 15 aMW of annual resource acquisitions.

Table ES-4. Achievable Class 2 (Energy-Efficiency) DSM Resource Potential by Customer Sector and Service Territory (aMW in 2027)

	Rocky Mountain Power	Pacific Power	PacifiCorp	
			System	As % of 2027 Baseline Sales
Residential	130	27	157	8%
Commercial	199	24	223	8%
Industrial	105	9	114	5%
Irrigation	6	2	8	6%
Total	**440**	**62**	**502**	**7%**

Note: Individual results may not sum to total due to rounding.

The commercial sector accounts for the largest share of achievable energy-efficiency savings at 223 aMW, followed by the residential sector at 157 aMW. An additional 122 aMW of electricity savings are projected as available in the industrial and irrigation sectors. Discretionary resources (i.e., retrofit opportunities) account for 379 aMW (75%) of the energy-efficiency savings. The remaining potential is associated with "lost-opportunity" resources, namely new construction and replacement of existing equipment at the end of its normal life cycle.

The cumulative, measure-specific supply curves for technical, economic, and achievable potential are illustrated in Figure ES-3. Each point on these curves shows the relationship between the levelized, per unit cost of the measure (vertical axis) and its marginal contribution to total energy savings (horizontal axis). Maximum technical, economic, and achievable potential[5] represents cumulative savings by 2027 and corresponds to the Class 2 DSM figures reported in Table ES-1.

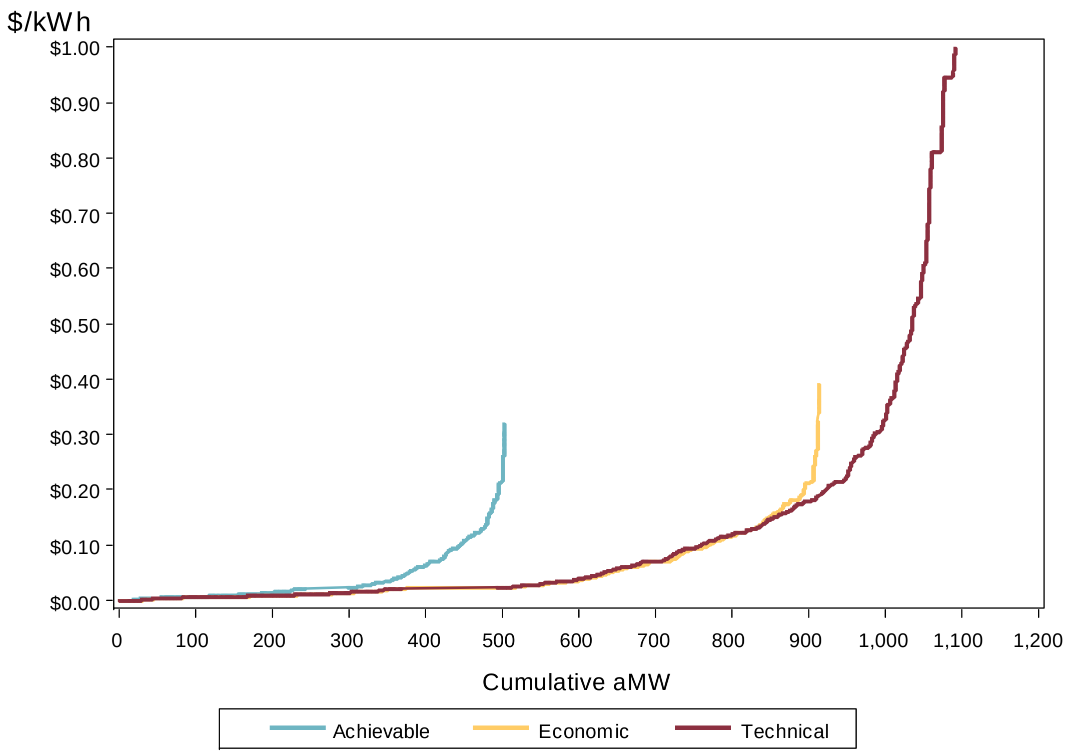
Regarding energy-efficiency resources (Class 2 DSM), this study's results are largely comparable with regional estimates developed by the Northwest Power and Conservation Council.[6] In its *5th Northwest Regional Electric Power and Conservation Plan*, the Council

5 Achievable potential includes a 15% administrative cost adder; therefore, the levelized cost threshold for calculating achievable potential is slightly lower than that used in the economic potential.

6 The timeframe of this study and its geographic coverage differ from those in the Council's analysis of the Northwest regional energy-efficiency potential. The two assessments also use different values for certain key economic assumptions, such as avoided costs and discount rate. There are also marked differences among regional utilities with respect to their customer mix, past conservation activity, and load growth patterns. The results of this study are, therefore, only loosely comparable to those reported by the Council.

estimated 2,800 aMW of conservation is expected to be achievable regionally by the year 2025, which represents approximately 15% of the 2005 base-year regional load. Based on the Council's "medium-case" forecast, regional conservation potential represents 32% of the projected 6,000 aMW growth in regional demand from 2005 to 2025. Using 2007 as the basis for calculations, the achievable energy-efficiency resources identified in this study represent 12%[7] of PacifiCorp's base-year load (excluding Oregon) and are expected to displace 22% of the projected 20-year load growth in the five states addressed in this study. Across these five states, technical and economic potential represents 41% and 33% of 2007 sales, respectively.

Figure ES-3. Class 2 DSM (Energy-Efficiency) Supply Curves for Technical, Economic, and Achievable Potential (aMW in 2027)



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7 This estimate is slightly lower than the Council's due to different assumptions about expected market acceptance. In its assessment, the Council assumed 85% of the economic potential would be achievable. However, this estimate does not prescribe the methods by which the savings might be acquired. For example, it is possible a significant portion of the savings may be realized through non-utility activities such as institution of stricter codes and standards or market transformation. Market research conducted for this study indicates the fraction of economic potential likely to be achievable is 55% on average across various customer sectors (see Section 3).

Energy Awareness and Education (Class 4 DSM) Resources

Resources in Class 4 DSM, targeted and non-targeted awareness and consumer education campaigns, are also expected to offer modest energy savings in addition to those available from Class 2 DSM resources. These savings, however, are difficult to measure, relatively unreliable, and, therefore, unsuitable for IRP assessments.[8] Based on a review of existing energy awareness programs in North America and PacifiCorp's own experiences, this study's results suggest modest additional savings of 4 aMW to 8 aMW per year might be possible through Class 4 DSM programmatic efforts.

Supplemental Resources

In addition to energy-efficiency and capacity-focused resources, this study also examined the potential for other end-user focused resources not considered in the standard definitions of Classes 1, 2, 3, and 4 DSM. These resources, which may be loosely defined as "dispersed generation," are considered "supplemental" to standard DSM resources and include energy-focused options such as combined heat and power (CHP), on-site solar, and capacity-based dispatchable standby generation (DSG).

Table ES-5. Achievable Supplemental Resource Potential by Technology and Service Territory (aMW and MW in 2027)

Achievable Potential	Rock Mountain Power	Pacific Power	PacifiCorp System
Energy-Focused Resources (aMW)			
CHP: Non-Renewable	43	16	59
CHP: Renewable	47	31	78
Solar: Photovoltaic	- - -	- - -	- - -
Solar: Efficiency Measures	- - -	- - -	- - -
Total Energy Potential (aMW)	***90***	***47***	***137***
Capacity-Focused Resources (MW)*			
DSG: Existing	34	0	34
DSG: New	76	26	102
Total Capacity Potential (MW)	***110***	***26***	***136***

*Does not account for 154 MW of peak demand reduction expected from energy savings of CHP.
Note: Individual results may not sum to total due to rounding.

8 Potential energy savings associated with long-term behavioral changes, to the extent they occur, are captured in the load forecasts and, hence, indirectly accounted for in the IRP process.

Resource Acquisition Costs

The total cost for acquisition of the 20-year achievable potential from all resources, exclusive of Class 4 DSM, is estimated at slightly over $1.1 billion in 2007 dollars ($945 million for Rocky Mountain Power and nearly $200 million for Pacific Power), including an estimated 15% for administrative expenses such as planning, program design, marketing, and ongoing operations. Energy-efficiency resources account for 52% (nearly $600 million) of the total resource acquisition costs (Table ES-6).

At approximately 4 cents/kWh, Class 2 DSM resources are the least-cost, energy-focused DSM options. Among the capacity-focused resources, Class 3 DSM options may be expected to provide capacity relief between $30/kW in the Rocky Mountain service territory and $24/kW in the Pacific Power service territory. The costs of supplemental resources are relatively high, at an estimated 6 cents per kWh for energy (CHP) and between $52 and $55 per kW for capacity (DSG).

Table ES-6. Base-Case Resource Acquisition Costs (NPV and Levelized) by Resource and Service Territory

Resource Class/Service Territory	Rocky Mountain Power		Pacific Power	
	20-Year NPV ($000)	Levelized Cost	20-Year NPV ($000)	Levelized Cost
Energy-Focused Resources				
Class 2 DSM Resource*	$512,296	$0.04/kWh	$86,288	$0.04/kWh
Supplemental Resource (energy)	$193,698	$0.06/kWh	$91,737	$0.06/kWh
Capacity-Focused Resources				
Class 1 DSM Resource	$164,347	$75/kW-year	$10,041	$50/kW-year
Class 3 DSM Resource	$41,196	$30/kW-year	$3,887	$24/kW-year
Supplemental Resource (capacity)	$32,972	$55/kW-year	$6,668	$52/kW-year
Total	**$944,509**		**$198,621**	

* Excludes Oregon.
Note: Individual results may not sum to total due to rounding.

Resource Potential under Alternative Scenarios

To provide an additional perspective on the potential for future resources and to account for uncertainties regarding future energy cost and market conditions, potential is estimated under alternative future scenarios concerning avoided costs and likely customer participation rates in various program offerings. The potential for DSM and supplemental resources are examined under three economic scenarios ("base-case," "high," and "low") and two achievable scenarios ("expected" and "high"). The economic scenarios are constructed based on the alternative avoided cost assumptions using IRP capacity and energy (customer class and end-use specific) cost decrements for each territory. Achievable scenarios are developed assuming different levels of market acceptance as a function of incentives offered to participants. For Class 1 and Class 3 DSM resources, the high scenario assumes a 50% increase in participant incentives. For Class 2

DSM resources, the scenarios assume market acceptance rates corresponding to 50% and 75% utility incentives (per data obtained from the survey of PacifiCorp's customers).

As seen in Table ES-7, changes in avoided costs are shown to significantly affect amounts of potential for all resources. The impacts are far more dramatic for Class 1 and Class 3 DSM resources because these fall into large discrete blocks. For example, under the expected (most likely) achievable scenario, potential for resources in Class 1 DSM change nearly threefold from the base-case to low economic scenarios. Class 2 DSM resources appear to be less sensitive to changes in avoided costs. For this class, a change in avoided cost decrement from its base-case to high value is expected to increase 58 aMW (12%) in resource potential under the expected achievable scenario. The effects of economic scenarios on supplemental resources are similar. For example, levels of achievable potential for energy-focused supplemental resources increase by 9% as avoided costs move from the base-case to high economic scenario.

Table ES-7. Achievable Potential in 2027 by Resource and Economic Scenario

Resource/Achievable Scenario	Economic Scenario		
	Base	High	Low
Class 1 DSM Resource (MW)			
Expected	285	286	104
High	125	374	125
Class 2 DSM Resource Energy (aMW)			
Expected	502	560	429
High	555	619	473
Class 3 DSM Resource (MW)			
Expected	190	196	160
High	336	336	210
Energy-Focused Supplemental Resource (aMW)			
Expected	137	138	75
High	171	172	94
Capacity-Focused Supplemental Resource (MW)			
Expected	136	153	110
High	204	230	165

Alternative assumptions concerning levels of customer acceptance of DSM programs also affect the amount of achievable potential. For Class 2 DSM, an increase in incentive levels from 50% to 75% of incremental measure costs (representing a 50% increase) can be expected to result in additional 53 aMW, or nearly 11%, of achievable potential under base-case economic assumptions. For supplemental resources, under the base-case economic scenario, 50% higher incentives are likely to change the resource potential by about 25% (from 137 aMW to 171 aMW). For Class 3 DSM, the same increase in incentive results in a similar increase in achievable potential (25%); yet Class 1 DSM resources actually *drop* under the high achievable scenario because higher incentive payments render several of the resources non-economic, thus reducing the overall potential.[9]

Acquisition of all identified energy-efficiency resources may also require increasing participant incentives above the current level of approximately 50% for most Class 2 DSM programs. Based on information provided by customers during the interviews, the results of this analysis suggest participation in energy-efficiency programs appears to be relatively inelastic with respect to incentive levels. Thus, a 50% increase in incentives (from 50% to 75% of measure costs) would lead to an increase of only 11% in resource potential. Moreover, although higher incentives do not affect total costs of the resource, they do increase the cost burden borne by the utility, leading to higher rate impacts with concomitant equity ramifications.

A full realization of the estimated 502 aMW of achievable energy-efficiency potential would require acquisition at the rate of approximately 25 aMW per year until 2027, or roughly 10 aMW more than PacifiCorp's more recent accomplishments. However, as more of the available potential is exhausted over time, greater effort (and resources) would be needed to acquire the remaining potential. The same argument may be made for capacity-focused resources in Class 1 and Class 3 DSM. In the area of supplemental resources, where PacifiCorp has less experience and other utilities have encountered challenges, it seems more reasonable to expect acquisition to begin slowly in the early years, accelerate in the medium term, and level off during the latter parts of the planning period.

Considering the Effects of Structural Changes

The analysis of achievable potential under alternative scenarios captures the effects of several macro-economic changes, such as fluctuations in energy prices, the institution of a carbon tax, and greater customer acceptance of DSM programs. There are, however, other structural changes, such as technological innovations and changes in public policy and regulation, which may profoundly affect the results of this study.

By their nature, studies of resource potential rely on large amounts of data and a number of pivotal assumptions concerning the future in calculating technical, economic, and achievable potential. Although this study explicitly accounts for the potential effects of emerging energy-efficiency technologies, uncertainties remain regarding future technological innovations and their market effects. For example, the assessment of the *technical* potential is inherently a static analysis and assumes "frozen" efficiencies for all baseline technologies. Advances in technologies that reduce the energy intensity of electrical equipment and appliances change the potential for various end-uses. Technological innovations that reduce costs, particularly in the area of on-site solar, may substantially improve the prospects for economic and achievable potential for supplemental resources.

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9 In economic analysis and screening of Class 1 and 3 DSM resources, incentives to participants represent "additional" costs, thus increasing total costs of the resource. In the case of Class 2 DSM resources, however, incentives are "transfers" between the utility and the participant, do not affect total resource costs, and have no impact on economic potential.

Studies of DSM potential provide a means of developing reliable estimates of the magnitude, costs, and timing of DSM resources, and, as such, are a necessary step in integrated resource planning. Resource potential studies also help inform the utility's DSM planning efforts. The objectives of resource potential assessment, however, are different from those of resource acquisition planning and program design in that they do not provide guidance as to *how* and by *what means* the identified resource potential might be realized. The potential for many of the electrical equipment or building shell measures might be realized through utility incentives or legislative action to institute efficiency codes and standards. For example, nearly 49% (78 aMW) of energy-efficiency potential in the residential sector derives from lighting measures, primarily the installation of compact fluorescent light bulbs. Should states in PacifiCorp's service territory decide to ban incandescent light bulbs through legislative action as other states have proposed to do, all identified potential may be realized without utility programs for the end-use customer.[10]

Although this study attempts to address some of these uncertainties in the context of different scenarios concerning economic and achievable potential, many uncertainties will remain given the length of the planning horizon. Therefore, these study findings should be considered "indicative" rather than "conclusive." Inevitably, much of the data used in this study will have to be updated, and many of its assumptions will need to be periodically revisited.

[10] Incandescent screw-in bulbs have already been banned in Australia, and similar action is being considered by the European Union and Canada. The idea is also being proposed in California.

1. Introduction

Background

PacifiCorp is one of the pioneers in utility-sponsored, demand-side management (DSM) services, with involvement dating back 25 years to the Hood River Conservation Project. That project, managed by PacifiCorp, and co-sponsored by the Bonneville Power Administration and other regional utilities, was the most comprehensive audit and weatherization project ever undertaken. Many of the marketing, delivery, and evaluation techniques used in energy-efficiency programs today have their origins in the knowledge and experience gained from the Hood River project.

Since the early 1980s, PacifiCorp has continued to be an innovator in energy efficiency. In the early 1990s, PacifiCorp conceived and implemented the Energy FinAnswer program, which has been the recipient of awards from the U.S. Department of Energy, the State of Oregon, the City of Portland, and the American Institute of Architects for its creative design and on-bill financing. The program was designed so the energy-efficiency investments were paid for through the reductions in the customer's bills, thus requiring no cash outlay by participants. This approach dramatically opened the market for energy efficiency in the commercial and industrial (C&I) markets. In the early 2000s, PacifiCorp successfully responded to a highly volatile energy market with two innovative and successful demand reduction programs: the 20/20 Program provided a 20% reduction in the energy rate to customers who were able to reduce their energy use by 20% over their prior year's use; and the Power Forward program combined energy saving tips with a public awareness mechanism.

Over the last 15 years, PacifiCorp has invested approximately $345 million in DSM programs, offsetting nearly 2,700 GWh of energy – the equivalent of nearly 515 MW of capacity annually, assuming a 60% load factor on average.[11] Currently, PacifiCorp operates successful capacity-focused programs for irrigation load curtailment, residential and small commercial air-conditioning direct load control, and Energy Exchange demand buyback (DBB), which together helped reduce PacifiCorp's peak loads by 149 MW in 2006. PacifiCorp also has an additional 260 MW available for control under curtailment agreements with a select group of its largest C&I customers.

Since the early 1990s, PacifiCorp has developed biennial integrated resource plans to identify the optimal, least-cost mix of resources to meet projections of its long-run resource requirements. The optimization process takes into account the capital, energy, and ongoing operation costs and the risk profile of various resource alternatives, including traditional generation, renewable generation, energy-efficiency, and capacity-focused resources.

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[11] Expenditures and savings include PacifiCorp's contributions to the Energy Trust of Oregon and the associated energy savings generated by those funds. All savings and capacity information calculated at generator.

Study Scope and Objectives

PacifiCorp commissioned this study to investigate the amounts of energy-efficiency and capacity-focused potential that remain within its service territory from conventional capacity-focused program options, energy-efficiency products and services, energy education, and other supplemental resources, such as solar, combined heat and power, and dispatchable standby generation. The results of this study will inform both the integrated resource planning process and assist PacifiCorp in revising and improving the design of existing programs and in developing new programs.

The principal goal in this study is to develop reliable estimates of the magnitude, timing, and costs of alternative DSM resources likely to be available to PacifiCorp over a 20-year planning horizon, beginning in 2008. The main emphasis of the study is on resources that may be expected to be realistically achievable during the planning horizon. The results of this study will begin to be incorporated into PacifiCorp's 2007 Integrated Resource Plan (IRP) update, scheduled to be completed in the 2008 calendar year.

The scope of this study encompasses multi-sector assessments of the long-run potential for DSM and other supplemental resources in PacifiCorp's Pacific Power (Oregon, Washington, and California) and Rocky Mountain Power (Idaho, Wyoming, and Utah) service territories.[12] As the Energy Trust of Oregon is responsible for the planning and delivery of energy-efficiency resources in Oregon, potential for these resources are exclusive of Oregon.

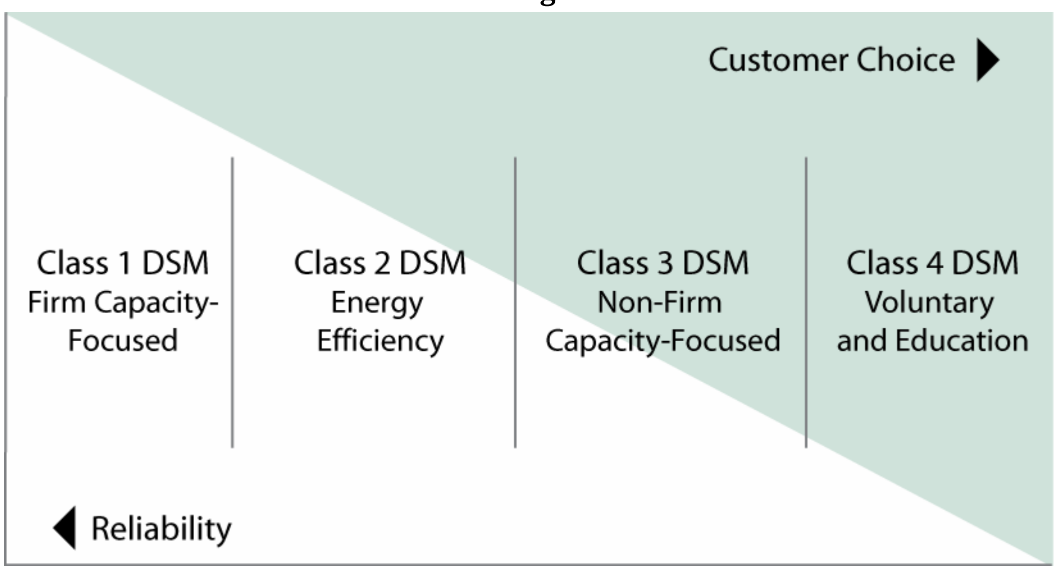
This study encompasses DSM resources included in PacifiCorp's classification of non-generation options as well as additional supplemental resources. According to this classification, DSM resources fall into four classes of activities or programs that promote the efficient use of electricity through various intervention strategies aimed at changing the intensity (energy efficiency), level (load response), timing (price response and load shifting), or behavior (education and information) in energy use. Supplemental resources primarily comprise small-scale, dispersed generation on the facility side of the meter.

The four resource classes, described in detail below, may be evaluated and categorized with respect to two main characteristics: reliability and customer choice. Class 1 DSM resources, including controlled and scheduled capacity-focused programs, are the most reliable – and verifiable – resources from a system planning perspective. In contrast, voluntary educational

[12] The scope of the study includes state-specific commitments made by MidAmerican Energy Holdings Company as part of its acquisition of PacifiCorp from Scottish Power in March 2006: California C6, Idaho I8, Utah U40, and Oregon O23. These are state-specific stipulations made under Mid-American Holding Company's Commitment 44a, related to a shareholder-financed study of the market potential for DSM resources by a third party. C6 provides settlement parties the opportunity to discuss the study's implementation, being I-8 involves an assessment of the market potential for the expansion of existing programs, including irrigation and Monsanto load curtailment programs in Idaho, and will compare the cost-effectiveness of DSM resources with comparable supply side resources. U40 commits PacifiCorp to an assessment of the market potential associated with irrigation and load curtailment programs in Utah as well as comparing the cost-effectiveness of DSM resources with comparable supply side resources. O23 states that MEHC and PacifiCorp agree to include representatives of both Community Action Directors of Oregon and Oregon Energy Coordinators Association in the list of interested parties participating in the DSM study public scoping process.

programs included in Class 4 DSM tend to be the least reliable. With respect to customer choice, Class 1 and Class 2 (direct load control/management and energy efficiency) are involuntary in that, once the equipment and systems are in place, savings may be expected to flow automatically. Class 3 and Class 4 DSM activities, on the other hand, involve a greater range of customer choice and control (see Figure 1). With the exception of dispatchable standby generation, supplemental resources are generally less firm due either to the uncertainties associated with their availability (solar) or to the extent of the customers control on how they are operated (combined heat and power [CHP]).

Figure 1. Reliability and Customer Choice Considerations in Demand-Side Management Resources



From a utility resource planning point of view as well as for analytic reasons, the resources assessed in this study may be categorized as follows: 1) capacity-focused resources (Class 1 and Class 3 DSM); 2) energy-efficiency resources (Class 2 DSM); 3) awareness and consumer education (Class 4 DSM); and 4) supplemental resources.

Capacity-Focused Resources (Class 1 and Class 3 DSM)

Capacity-focused (or demand-response) resources encompass both Class 1 and Class 3 DSM. These resources are comprised of flexible, price-responsive loads that may be curtailed or interrupted in whole or part during system emergencies, periods of high market prices, or alleviation of stressed distribution/transmission resources, and, by so doing, provide greater reliability to the system. Capacity-focused objectives may be met through a broad range of price-based (e.g., time-varying rates and real-time pricing [RTP]) or incentive-based (e.g., direct load control and demand buy-back) program options. For the purposes of this study, capacity-focused resources are defined based on PacifiCorp's characterization of two distinct classes of firm and non-firm resource options:

- ***Class 1 (Firm) DSM Resource***. This class of options allows either direct or scheduled interruption or cycling of electrical equipment and appliances, such as central air-conditioners, irrigation pumps, lighting, and process loads.
- ***Class 3 (Non-Firm) DSM Resources***. Resources in this class can be based on incentives to customers to reduce consumption when requested by the utility, such as curtailable tariffs or DBB. Program options in this class can also include tariff-based resources, such as traditional time-of-use (TOU), critical peak pricing (CPP), or RTP.

Energy-Efficiency Resources (Class 2 DSM)

This group is comprised of technologies that reduce energy consumption at the end-use level, including both high-efficiency equipment and measures that lower energy use in appliances through shell improvements, control installation, etc. These resources are generally categorized as either discretionary (retrofit in existing construction) or lost opportunity resources (equipment replacement and efficiency improvements in new construction). These resources can be captured through the application of various market intervention mechanisms, such as equipment incentives, direct installation, audits and information, or codes and standards. The type and intensity of the market intervention strategy as well as the prevailing retail rates can affect the cost and amount of the energy-efficiency resource captured.

Non-targeted Awareness and Energy Education (Class 4 DSM) Resources

These initiatives consist of education resulting in reductions in energy use and demand, primarily through behavioral changes. These programs can be very effective, but specific program results typically have not been relied on for planning purposes. Examples include PacifiCorp's participation in the State of Utah's Power Forward program, California's Flex Your Power program, Wisconsin's Energy Center, and adult and public school education programs, various brochures, newsletters, billing messages, advertising, and other types of public education and awareness programs. These efforts promote reductions in energy usage through behavioral changes, such as conservative thermostat settings, turning off appliances, and increased awareness of other resource acquisition program offerings. Although the impacts of such programs may not be explicitly considered in the resource planning process, they are typically captured naturally in long-term load growth patterns.

Supplemental Resource Options

In this study, "supplemental" resources represent small-scale, dispersed power generation technologies that may be considered as an addition to conventional DSM resources. Resources in this category may be characterized as "hybrid" options that may incorporate features of both supply-side and demand-side resource features. For the purposes of this assessment, three options are considered: 1) *CHP* is the simultaneous generation of energy and heat, in which waste heat is captured and used for industrial process heating, space heating, and/or domestic hot water; 2) *On-Site Solar* is assumed to include small-scale photovoltaic (PV) and solar efficiency measures; 3) *Dispatchable Standby Generation* consists of back-up power-generating equipment installed at the customers' facilities that may be subject to dispatch by the utility for a certain number of hours each year during peak load hours.

Additional Areas of Research

The study's analyses of resource potential are augmented by two complementary research efforts. The first component involves a study of future structural changes, such as technological innovation, macro-economic conditions, and public policy as well as how these might affect this study's findings and conclusions. The second, provided in Volume II, Appendix G, is an assessment of the treatment of externalities in PacifiCorp's IRP process and how it compares with practices of other utilities in North America.

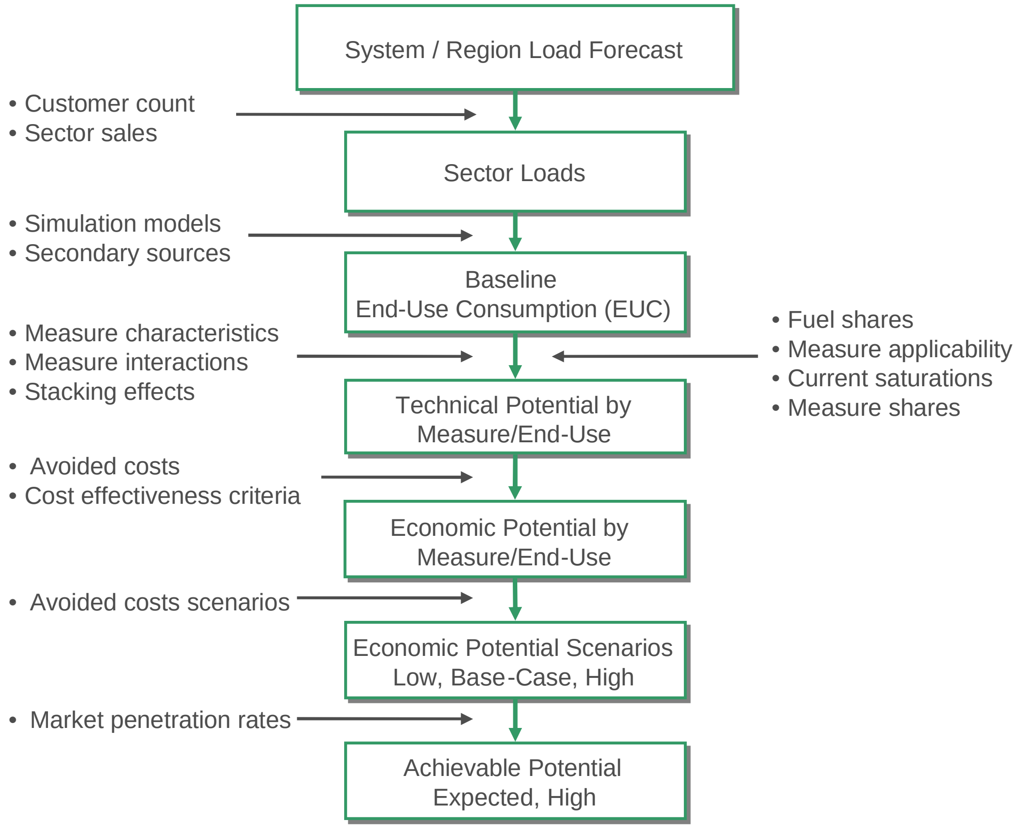
General Approach

Resources analyzed in this study differ with respect to several salient attributes, such as the type of load impact (energy or capacity), availability, reliability, and applicability to various customer classes and customer segments (business, dwelling, or facility types). They also require fundamentally different approaches in program design, incentive structures, and delivery mechanisms for their deployment. Therefore, analysis of the potential for these resources requires methods tailored to address the unique technical and market characteristics of each resource. These methods, however, generally spring from a common conceptual framework, and their applications to various resources rely on similar analytic methodologies.

This general methodology is best described as a combination "top-down/bottom-up" approach. As illustrated in Figure 2, the top-down methodology component begins with the most current load forecast, decomposes it into its constituent customer sector, customer segment, and end-use components. The bottom-up component considers the potential technical impacts of various demand-side and supplemental resource technologies, measures, and practices on each end use, which are then estimated based on engineering calculations, taking into account fuel shares, current market saturations, technical feasibility, and costs. These unique impacts are aggregated to produce estimates of resource potential at the end-use, customer sector, and service territory levels. In many ways, the approach is analogous to generating two alternative load forecasts at the end-use level (one with and one without DSM and supplemental resources), and calculating resource potential as the difference between the two forecasts.

Estimation of technical and economic potential in this study is based on best-practice research methods and analytic techniques that have become standard in the utility industry. These techniques are also consistent with the conceptual approach and methodology used by other planning entities within PacifiCorp's service area, including the Northwest Power and Conservation Council, in developing regional energy-efficiency potential. Consistent with accepted industry standards, this study's approach distinguishes among four definitions of resource potential widely used in utility resource planning: "naturally occurring conservation," "technical potential," "economic potential," and "achievable potential."

Figure 2. General Methodology for Assessment of Demand-Side Resource Potential



Naturally occurring conservation refers to reductions in energy use that occur due to normal market forces, such as technological change, energy prices, market transformation efforts, and improved energy codes and standards. In this analysis, naturally occurring conservation is accounted for in several ways. First, the potential associated with certain energy-efficiency measures assumes a natural rate of adoption. For example, the savings associated with ENERGY STAR appliances account for current trends in customer adoption. Second, current codes and standards are applied in the consumption characteristics of new construction. Finally, the assessment accounts for the gradual increase in efficiency as older equipment in existing buildings is retired and replaced by units meeting current standards. However, this assessment does not forecast changes to codes and standards; rather, it treats them at a "frozen" efficiency level.

Technical potential assumes all available DSM measures and supplemental resource options may be implemented, regardless of their costs or market barriers. For energy-efficiency resources, technical potential further falls into two classes: "discretionary" (retrofit) and lost-opportunity resources. It is important to recognize that the notion of "technical potential" is less relevant to resources such as capacity-focused programs and distributed generation since most end-use loads may be subject to interruption through load curtailment or displacement by on-site generation from a strictly "technical" point of view.

Economic potential represents a subset of technical potential only consisting of those measures deemed cost-effective in comparison to the utility's total avoided costs, based on a total resource cost (TRC) test criterion. For each measure, the test is structured as the ratio of the net present values of the measure's benefits and costs. Only measures with a benefit-to-cost ratio of 1.0 or greater are deemed cost-effective and are retained in the resource portfolio. The methodology for cost-effectiveness calculations and relevant benefit and cost elements are described in detail in Section 3 of this report for Class 2 DSM resources. Instead of using a benefit/cost ratio as the basis for screening, economic potential in Class 1 and Class 3 DSM and supplemental resources were determined by calculating levelized costs for each resource, then eliminating resources with a per-unit cost greater than the levelized avoided capacity and energy costs in each service territory.

Achievable potential is defined as the portion of economic potential that might be assumed to be reasonably achievable in the course of the planning horizon, given market barriers that may impede customer participation in utility programs. Assumed levels of achievable potential are meant to serve principally as planning guidelines and to inform the IRP process.

Knowledge of alternative resource options and reliable information on their long-run resource potential are the necessary ingredients for sound integrated utility resource planning. The principal goal in resource potential studies is to develop reasonably reliable estimates of the magnitude, costs, and the timing of alternative resources likely to be available over the course of the planning horizon. They are intended as a means of identifying and assessing resource potential likely to be available in a specific market over a defined time period; they are not meant to provide guidance as to *how* or by *what means* identified resources might be acquired. For example, identified potential for many electrical equipment or building shell measures might be attained through utility incentives or legislative action instituting more stringent efficiency codes and standards.

Resource potential studies are complex undertakings, requiring large amounts of technical and market data and relying on a number of pivotal assumptions concerning the future to calculate the technical, economic, and achievable potential. For example, the assessment of the *technical* potential assumes "frozen" efficiency levels for all baseline technologies in place today. Economic potential for DSM resources is determined using a TRC criterion, which is based on a *societal* perspective to determine cost-effectiveness of various resource options without consideration for who pays for the efficiency measure or how its costs might be shared between the utility and program participants. Clearly, the customer's willingness to participate in demand-side programs has much to do with their energy cost and the incentive amounts offered by the utility; the higher the retail costs and the incentive, the greater the likelihood they would participate in the program.

This study addresses some of these uncertainties in the context of an analysis of effects of structural changes. Given the length of the planning horizon, however, many uncertainties will remain. The planning process is ultimately dynamic, reflecting changing market conditions. Therefore, it is important the study findings be considered "indicative," rather than "conclusive." Inevitably, much of this study's data will have to be updated, and many of its underlying assumptions will need to be revisited periodically.

Resource Interactions

The methodology in this study explicitly accounts for technical interactions occurring both *within* (among various options and measures) and *between* the four resource classes. There are several interactions accounted for within the Class 2 DSM analysis. First, the "stacking effect" occurs when *complementary* retrofit measures, such as wall, ceiling, and floor insulation, are applied to a single end use. Since measure savings are always calculated in terms of reductions in end-use consumption, installation of one measure clearly will reduce the savings potential of measures installed subsequently.

A similar effect occurs when equipment and non-equipment (retrofit) measures within Class 2 DSM compete for the same end use (e.g., a SEER 16 central air conditioner and high-efficiency windows). As with the stacking effect, if non-equipment measures are captured first, replacement of existing equipment with high-efficiency equipment can be expected to have a smaller impact on end-use consumption than if the replacement had taken place first. Clearly, the ordering of measures depends on practical considerations concerning energy-efficiency program design and implementation. For this study, it is assumed measures with the highest savings opportunities would be implemented first and equipment replacement will always precede non-equipment measures. Finally, technical interactions among measures such as lighting retrofit and weather-sensitive loads are accounted for in the analysis; depending on the season, the heat loss from efficient lighting may increase (in winter) or decrease (in summer) power consumption in HVAC.

Interactions also occur between two or more classes of resources. The most obvious are the effects of energy efficiency on capacity-focused potential as implementation of energy-efficiency measures lower peak demand and thus reduce the technical potential for capacity-focused resources. Similar interaction effects are expected among capacity-focused options (such as curtailable tariffs) and supplemental resources (such as dispatchable standby generation).

Organization of the Report

This report is organized in two volumes. The present document, Volume I, is organized in six sections. The next four sections following this introduction are devoted to an analysis of various resource options, namely: capacity-focused resources (Class 1 and Class 3 DSM); energy-efficiency resources (Class 2 DSM); education and information (Class 4 DSM): and supplemental resources. Each section begins with a description of the scope of the analysis, then presents a summary of potential for the resource, a complete discussion of methodologies, and presentation of detailed results. Section 6 examines the effects of alternative economic scenarios and structural changes on the potential for each resource. Supplemental technical information, assumptions, data, and other relevant details are presented in Volume II as appendices and electronically.

2. Capacity-Focused Resources (Class 1 and Class 3 DSM)

Scope of Analysis

Demand-side resources with a focus on reducing capacity needs are often referred to as demand response or load management programs. These programs are designed to help reduce peak demand during system emergencies or extreme market prices, promote improved system reliability, and, in some cases, may lead to the deferment of investments in delivery and generation infrastructure. These benefits occur by providing incentives to customers to curtail loads during utility-specified events (programs include direct load control, irrigation control, curtailable tariffs, and DBB programs) or by using pricing structures to induce participants to shift load away from peak periods (e.g., TOU rates, critical peak and RTP programs). For this study, capacity-focused resources have been defined based on PacifiCorp's characterization of two distinct classes of "firm" and "non-firm" resource options.

Class 1 (Firm) DSM Resource. This class of capacity-focused program options offers the most reliable resource to the utility. Strategies in this category allow total or partial interruption of electric loads for equipment and appliances such as central air conditioners, irrigation pumps, lighting, and process loads. Load interruptions may be achieved through direct control by the utility (or a third-party under contract to the utility), on a scheduled basis using timers, or through coordination with energy management systems. Because of their relatively high reliability, resources of this nature are generally considered "firm" resources from a planning perspective. Three general program options are analyzed in this study:

1. *Direct Load Control (DLC)* programs allow PacifiCorp to remotely interrupt or cycle electrical equipment and appliances at the customer's facility. In this study, the assessment of DLC program potential is analyzed for small commercial and residential central electric cooling (including heat pumps) and electric water heating. Large commercial customer DLC is also considered, using integration with existing energy management systems having additional controls on lighting, HVAC, and plug loads.
2. *Irrigation Load Curtailment* has two program options. The first is a DLC option where PacifiCorp has direct control over irrigation pumps; the second is a scheduled irrigation program where participants determine at the beginning of the summer which days of the week and the number of hours per day they will allow their irrigation pumps to be controlled.
3. *Thermal Energy Storage (TES)* programs are designed to reduce the demand associated with cooling during on-peak periods. Ice is made during off-peak periods (unoccupied times at night) using the existing cooling system; this ice is saved and used to cool the building during peak demand periods. This mitigates customer high demand and energy charges during on-peak periods. This program is targeted at large commercial customers with rooftop cooling units.

Class 3 (Non-Firm) DSM Resources. In this class of programs, incentives are either in the form of event-by-event payments or time-differentiated rate structures. These program options are less reliable than those in Class 1 DSM because, strictly speaking, they are not "dispatchable" by the utility, program participation per event is voluntary, and their contributions typically cannot be measured until after the fact. Class 3 DSM resources include curtailable tariff programs, time-varying prices (TOU, RTP, and CPP), and DBB or demand bidding programs. Incentives are provided to participants either as a special tariff (time-varying prices) or per-event payments (DBB). Five specific program options in this class of resources are analyzed in this study:

1. *Curtailable Tariffs* programs refer to contractual arrangements between the utility and its customers who agree to curtail or interrupt their loads in whole or part for a predetermined period when requested. In most cases, mandatory participation is required once the customer enrolls in the program; however, these programs may include provisions for the customer to exercise an economic buy-through of a curtailment event. Incentives are paid regardless of the quantity of events called each year (less any penalties associated with an event buy-through). This analysis assumes this program targets C&I customers with average monthly loads greater than 250 kW. This portion of the potential only includes expected load reductions; the potential for using backup generators is assessed in Section 5, Supplemental Resources.

2. Under *DBB* arrangements (such as PacifiCorp's Energy Exchange Program), the utility offers payments to customers for voluntarily reducing their demand when requested by the utility. The buyback amount generally depends on market prices published by the utility ahead of the event, coupled with the customer's ability to curtail use during the hours load is requested. The reduction level achieved is verified using an agreed upon baseline usage level specific to the participating customer. As with curtailable tariffs, this program also targets C&I customers with loads greater than 250 kW.

3. *Time-of-Use* programs are based on generally two- or three-tiered time-differentiated tariff structures that charge fixed prices for usage during different blocks of time (typically on- and off-peak prices by season). TOU rates are designed to more closely reflect the marginal cost of generating and delivering power. This study analyzes the potential for TOU rates only for the residential sector; C&I TOU rates are typically considered a standard tariff and not a capacity-focused program option.

4. *Critical Peak Pricing* or extreme-day pricing refers to programs that aim 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. For the residential and small commercial sectors, it is assumed enabling technology (smart thermostats) is installed; for larger commercial customers (greater than 30kW), interval meters would be installed.

5. *Real-Time Pricing* is a tariff structure for customers to pay electric rates tied to market prices. The prices are typically posted by the utility based on day-ahead hourly prices. RTP price structures are most suitable for large C&I customers with flexible schedules which may be adjusted on short notice. This analysis assumes an RTP tariff would target large C&I customers (greater than 250 kW).

The program options listed under Class 1 and Class 3 DSM resources are based on a thorough literature review cataloging and classifying capacity-focused strategies offered by utilities and regional transmission organizations across the country. For each program offering, data were collected on the offerings' main features, such as objectives, program periods, eligibility criteria, curtailment event triggers, incentive structures, and technology requirements. These program options are described in more detail later in this section. Detailed design specifications and assumptions underlying the analysis of each program option are reported in Volume II, Appendix B.

Assessment Methodology

Capacity-focused resources differ from other DSM options, particularly energy efficiency, in at least three important respects which affect how potential is calculated. First, they depend on ongoing, active participation by customers; that is, they require customers participate in an ongoing program (annually or periodically). Second, unlike energy-efficiency resources, capacity-focused strategies result in either a total or partial shift of when energy is used, and therefore affect the quality and availability of service to the customer. Finally, while energy-efficiency measures continue to provide savings over the measure's normal life, the impacts of capacity-focused program options depend on customers' ability and willingness to participate in individual events; hence, they depend largely on program design features such as incentive levels, number of events, whether the program is assumed to be mandatory or voluntary, and whether or not there penalties exist for non-performance, such as liquidated damage provisions.

Because of this, capacity-focused options are not equally applicable to or effective in all segments of the electricity consumer market, and their impacts tend to be end-use specific. This study employs a combination, "top-down"/"bottom-up" approach. As in the case of energy-efficiency, demand-response opportunities begins with a "technical" assessment of the quantity of load available during peak periods and the portion of this which is technically feasible to expect during curtailment periods. Significant background research of capacity-focused programs nationwide, including 15 surveys of program administrators and 215 surveys of PacifiCorp C&I customers, are used to inform the quantity of potential achievable. The assessment of resource potential involved seven principal steps described below.

1. Secondary and Primary Data Collection and Research. This study required compilation of a database on load data, end-use and appliance saturations, demand response impacts, and costs, which were gathered from multiple sources. To the extent possible, this study has sought to rely on demand forecasts and usage data available from PacifiCorp to calibrate the results more closely to unique service territories. Specific data elements and their respective sources are listed in Table 1.

In estimating the technical and achievable potential impacts of various capacity-focused resources, it is important to consider the effectiveness and the results of similar program options applying the same technologies or program designs. The research in this study used a two-pronged approach to gather information on other programs. It began with secondary research of available literature on existing programs in North America (including program descriptions, evaluation reports, regulatory filings, trade journal publications, and conference proceedings). In addition, a survey of utility load management program administrators was conducted to gather more specific information on program costs, event participation rates, and other program characteristics relevant to estimating the resource potential. This primary research resulted in data on a range of estimates for key program parameters. In all, about 60 programs were reviewed.

In addition to researching existing programs and to develop a better perspective on PacifiCorp's customers' sentiments regarding capacity-focused programs, a survey of 215 C&I customers was conducted to elicit information on the customers' response to and likelihood of participating in various program options. (The results of this survey are reported in Volume II, Appendix A.)

Table 1. Class 1 and Class 3 DSM Data Sources

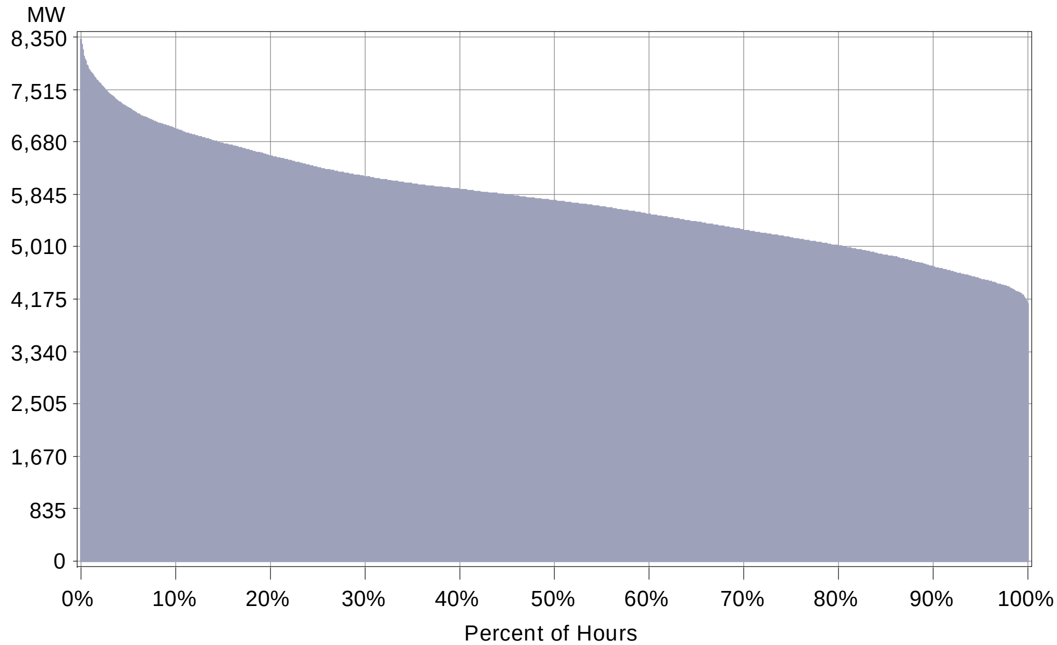
Data	Sources
Hourly System Load Profile	PacifiCorp 2000-2005 hourly profiles by rate class
End-Use Shares and Load Shapes	Calibrated Class 2 DSM end-use percentages for each state and market sector
	Building Simulation Load Shapes
	Northwest Power and Conservation Council & ELCAP load shapes (1999)
End-Use and Appliance Saturations	PacifiCorp Energy Decisions Surveys - Residential and Commercial
	Commercial Building Stock Assessment - Northwest Energy Efficiency Alliance, 2002
Technical Factors	Audits conducted by Nexant Inc.
	Surveys of program administrators
	California Energy Commission
	Edison Electric Institute (EEI)
	Peak Load Management Alliance (PLMA)
	Various RTO and utility reports
Costs	Surveys of program administrators
	PacifiCorp program experience
	Various RTO and utility reports

* Note that references were screened for geographic and market applicability

2. Estimating Total Load during Curtailment Periods. In estimating the quantity of potential available during likely curtailment periods, it is important to first assess the actual peak-coincident loads for various customer sectors and segments as individual customers' peak loads do not necessarily coincide with system peaks. This non-coincidence of peak demand and system peak must be correctly accounted for in any study of capacity-focused resource potential; this study refers to these estimates as the "load basis."

Using the system hourly shape for 2006, Figure 3 displays the load duration curve representing the average demand (MW) during each percentile of hours in the year.

Figure 3. PacifiCorp System Load Duration Curve (2006)



The first step in the process of estimating the load basis was to define customer sectors, customer segments, and applicable end uses, similar to the energy-efficiency study. System loads were disaggregated into three sectors: (1) residential; (2) commercial; and (3) industrial. Each sector was broken down further by state, sectors (Table 2) and finally end uses (including cooling, hot water heating, lighting, plug load, refrigeration, space heating, and the sum of all end uses).

Table 2. Capacity-focused Analysis Customer Sectors and Segments

Residential	Commercial	Irrigation	Industrial
Single Family	Grocery	Irrigation Pumping	Food Manufacturing
Manufactured	Health		Lumber Wood Products
Multifamily	Large Office		Paper Manufacturing
	Large Retail		Chemical Manufacturing
	Lodging		Petroleum Refining
	Miscellaneous		Stone Clay Glass Products
	Restaurant		Primary Metal Manufacturing
	School		Industrial Machinery
	Small Office		Electronic Equipment Mfg
	Small Retail		Mining
	Warehouse		Transportation Equipment Mfg
			Miscellaneous Manufacturing

The load bases during the likely curtailment periods (the highest 40 hours for the winter and summer seasons) are estimated for each state, sector, and end-use combination by spreading PacifiCorp's 2006 energy sales over end-use hourly load profiles and calibrating them to actual customer sector loads (Figure 4). This provides detailed estimates of demand for each hour of the year for each end-use/sector/state combination. End-use and sector loads are then aggregated to create hourly load shapes for Rocky Mountain Power (Idaho, Utah, Wyoming) and Pacific Power (California, Oregon, Washington) territories.

Because PacifiCorp is a summer-peaking utility, the summer period is most important for demand response, as curtailments will primarily happen during on-peak weekday periods. Figure 5 shows the calibrated load for each hour on the average summer weekday for each end use (see Volume II, Appendix B for additional details).

Figure 4. PacifiCorp System Monthly Sales (MWh) by Sector

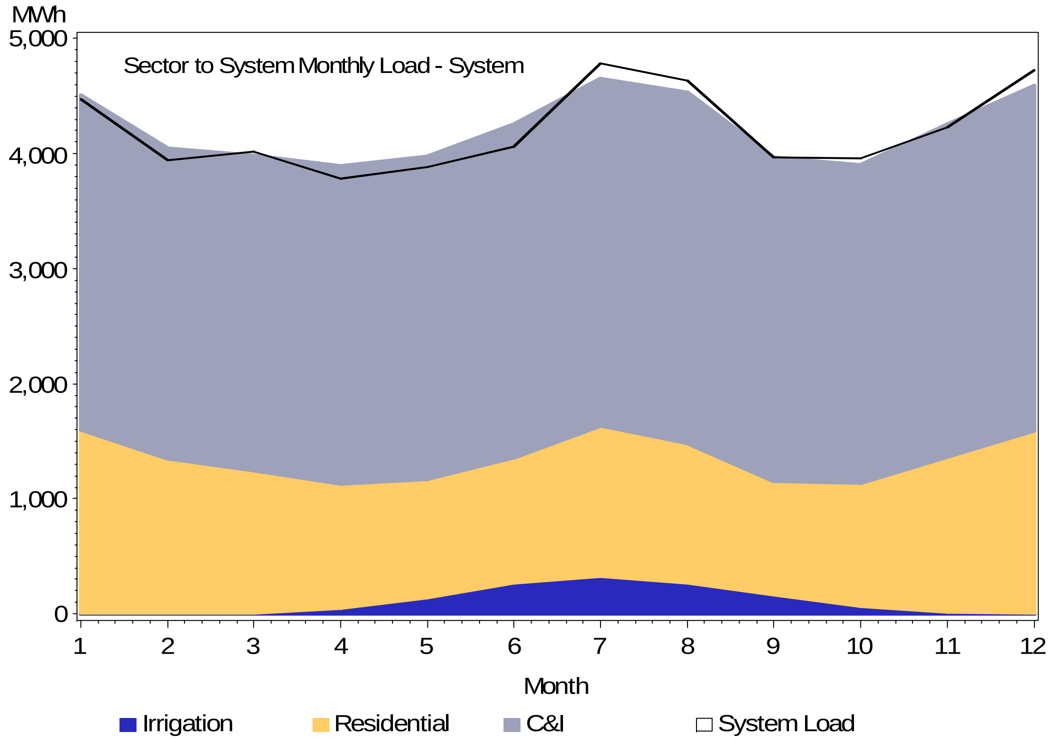
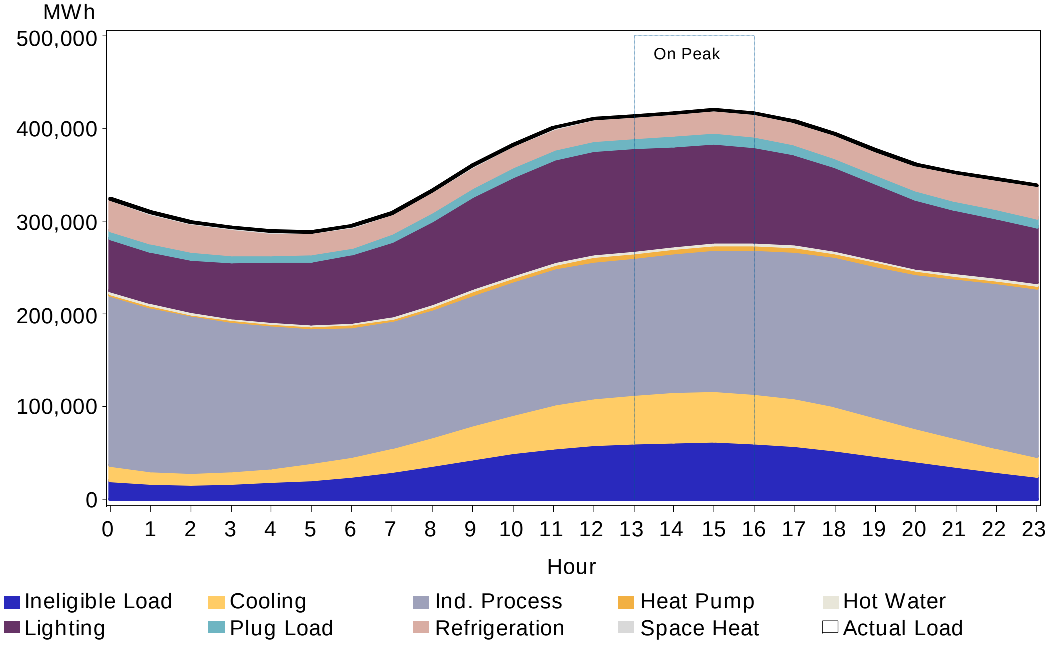


Figure 5. Average Summer Weekday Load – All End Uses



3. Determining Technical Potential. For capacity-focused options, it is theoretically possible to shed all loads during an event, but the resource potential would then equal system load, which is not useful for planning purposes and not practically feasible. Therefore, technical potential is estimated by first adjusting the load basis to account for customer sectors and segments eligible for the program and the load level that meets eligibility requirements (e.g., many commercial programs target large customers with loads over 250 kW). Additionally, estimates were developed for the actual end uses and the fractions of end-use loads likely to be available for curtailment. The latter information was developed from multiple secondary sources, including evaluation reports and technical studies of participants in existing programs. For example, the direct load control program for large commercial sites targets multiple end uses such as cooling and lighting and available audits of large C&I customers are used to estimate the portion of each end-use load that would likely be curtailed.

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

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

and

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

where:

LE_{ps} (load eligibility) represents the percent of customer sector (s) loads applicable for program option (p), referenced as "Eligible Load" in Volume II, Appendix B; and

LI_{pes} (load impact) is the percentage reduction in end-use load (e) for each sector (s) resulting from program (p), referenced as "Technical Potential as % of Load Basis" in Volume II, Appendix B.

4. Estimating Market Potential. Market potential is a subset of technical potential and takes into account the customers' ability and willingness to participate in capacity-focused programs subject to their unique business priorities, operating requirements, and economic (price) considerations. Estimates of market potential are derived by adjusting technical potential by two factors: expected rates of *program* participation and expected rates of *event* participation. Market potential for the program option (MP_p) is calculated as the product of technical potential for the customer sector (s), program participation (sign-up) rates (PP_{ps}), and expected event participation (EP_{ps}) rates, thus:

$$MP_p = TP_{ps} \times PP_{ps} \times EP_{ps}$$

For each capacity-focused program, the assumed rates of program sign-up for all customer segments are informed based on secondary research described above as well as on PacifiCorp's past program experience. Because of the variations in program structures, their incentive levels, and customer mix, in many cases information on program participation was not transferable to PacifiCorp's service territory. Therefore, a survey of C&I customers was used as a basis for determination of the market potential for various capacity-focused options for segments of C&I customers.

As part of these surveys, respondents were asked about their organization's attitude toward a series of capacity-focused program options. The results of the survey, summarized in Table 3, indicate relatively positive attitudes toward more voluntary, less firm (Class 3 DSM) resources, such as demand buy-back and CPP programs as opposed to more reliable and firm (Class 1 DSM) resources, such as direct load control programs. One exception was hourly pricing, which was also less desirable to customers, most likely due to their expectations of price volatility.

Table 3. C&I Survey Results: Attitude toward Capacity-Focused Program Options

Attitude	Demand Buy-Back	Critical Peak Pricing	Hourly Pricing	Curtailment Contracts	Direct Load Control
Very Positive	11%	12%	3%	5%	2%
Somewhat Positive	36%	45%	22%	33%	11%
Somewhat Negative	18%	14%	27%	21%	16%
Very Negative	9%	18%	33%	34%	59%
Don't Know	27%	10%	15%	7%	11%

Survey respondents were offered a list of various capacity-focused program options and asked which program(s) – assuming equal availability – they would be most likely to participant in.

Respondents were also given the option of choosing "no program." Response frequencies to this question by each customer segment provided the basis for the market potential estimates (Table 4). The average value was used for segments with sample sizes too small to be statistically valid.

Table 4. C&I Survey Results: Program Preferences

	Demand Buy-Back Type Program	Critical Peak Pricing	Hourly Pricing	Curtailment Contracts	Direct Load Control	None
Grocery	20%	12%	2%	13%	0%	52%
Health	0%	0%	0%	0%	0%	100%
Large Office	20%	8%	0%	21%	0%	48%
Large Retail	20%	16%	0%	8%	0%	53%
Lodging	0%	0%	0%	0%	0%	100%
Miscellaneous	20%	12%	2%	13%	0%	52%
Restaurant	15%	25%	0%	25%	0%	35%
School	0%	18%	5%	23%	0%	54%
Small Office	20%	8%	0%	21%	0%	48%
Small Retail	20%	16%	0%	8%	0%	53%
Warehouse	20%	12%	2%	13%	0%	52%
Industrial	20%	24%	4%	6%	0%	44%

5. Estimation of Costs and Supply Curves. Capacity-focused programs vary significantly with respect to both type and level of costs. Applicable resource acquisition costs for capacity-focused 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. As in all other resource classes, capacity-focused resources assume a PacifiCorp administrative adder of 15% on annual program costs. The assumptions and data used in the analysis are described in greater detail in Volume II, Appendix B.

The levelized cost ($/kW-year) of each program option is calculated over the 20-year period using cost estimates of upfront program development, installed technology, incentives, ongoing maintenance, administration, and communications. Finally, estimates of market potential are combined with per-unit resource costs to produce resource supply curves.

6. Estimating Economic Potential. Capacity-focused options with levelized life cycle costs that exceed PacifiCorp's avoided cost of capacity ($98 for Rocky Mountain Power, $58 for Pacific Power[13]) are removed from the technical potential to create an estimate of economic potential.[14]

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13 Rocky Mountain Power has a higher decrement value due to capacity constraints during summer peak times driven by substantial air conditioning loads.

14 For consistency with Class 2 resources, this report shows economic potential as a subset of technical potential, although the levelized costs are based on market potential. Levelized costs must be estimated for the actual expected output of the capacity-focused program option, which requires estimates of program sign-up and event participation.

PacifiCorp's estimates of the marginal cost of capacity (decrement) are used as a threshold for determination of cost-effectiveness. In 2006, PacifiCorp conducted an IRP process using levelized costs of capacity-focused resources provided by the 2006 Proxy Study.[15] For each service territory, the modeling process chose programs that lowered the overall cost of generation and excluded those that increased total costs. This process provided a range of decrement values, for which PacifiCorp staff approximated a median cost. PacifiCorp is in the process of upgrading the capacity expansion model used for IRP and refining its DSM modeling process to improve estimation of these data points for future updates.

7. Estimating Achievable Potential. Achievable potential is calculated as that portion of market potential with levelized life cycle costs less than PacifiCorp's avoided cost of capacity.

Resource Potential

Table 5 and Table 6 report estimated resource potential for Class 1 and Class 3 DSM resources during the top 40 hours of summer for the residential, commercial, and industrial sectors for each of the two territories. Technical potential is highest in the residential sector due to opportunity for the air conditioning load control program. It is assumed no Class 1 DSM option would be applicable to the industrial sector because of the improbability of customers allowing the utility direct control of industrial loads. The resource potential in the commercial sector includes direct load control and thermal energy storage.[16] Once economic screens (base-case levelized capacity cost threshold of $98/kW-year for Rocky Mountain Power and $58/kW-year for Pacific Power) are applied to the technical potential; commercial DLC and thermal energy storage are excluded because they do not meet the cost-effectiveness criteria.

For the Rocky Mountain Power territory, the Class 1 DSM achievable potential of 265 MW is driven by the irrigation load curtailment program (irrigation sector) and direct load control of air conditioning (residential and small commercial sectors). These results include the quantity of curtailment currently contracted under Rocky Mountain Power's Irrigation Curtailment and Cool Keeper program. The Cool Keeper program has 177 MW of load signed up for the program, resulting in 89 MW of reduction during curtailment periods. Recently, PacifiCorp has had success with the irrigation control program in Idaho and Utah, with an average reduction of 53 MW and 3 MW, respectively. In 2007, the irrigation program expects an additional 25 MW of net load reduction available through the addition of a direct load control option, totaling 81 MW of irrigation potential and 170 MW of Class 1 DSM reductions in total. Therefore, the remaining potential for PacifiCorp to achieve is 94 MW.

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15 Haeri, Hossein and Lauren Gage, Quantec LLC. "Demand Response Proxy Supply Curves," September 2006

16 Please note that Curtailable Tariff programs are considered Class 3 under PacifiCorp definitions

**Table 5. Class 1 DSM: Rocky Mountain Power Territory
Technical, Economic, and Achievable Potential (MW in 2027)**

Sector	Technical Potential	Economic Potential	Achievable Potential	Achievable as % of 2027 Peak
Residential	881	881	160	8%
Commercial	511	111	1	0%
Industrial	---	---	---	---
Irrigation	308	308	104	22%
Total	**1,700**	**1,300**	**265**	**3%**

Note: Individual results may not sum to total due to rounding

For the Pacific Power territory, the irrigation program is the only economically-viable option, providing 20 MW of achievable potential in year 2027 (Table 6). Pacific Power has significantly less irrigation load, resulting in substantially lower potential.

**Table 6. Class 1 DSM: Pacific Power Territory
Technical, Economic, and Achievable Potential (MW in 2027)**

Sector	Technical Potential	Economic Potential	Achievable Potential	Achievable as % of 2027 Peak
Residential	227	---	---	---
Commercial	178	---	---	---
Industrial	---	---	---	---
Irrigation	108	108	20	8%
Total	**513**	**108**	**20**	**0%**

Note: Individual results may not sum to total due to rounding

With respect to Class 3 DSM resources, the highest technical potential is in the industrial sector for Rocky Mountain Power. Technical potential is high in this case because it does not account for the interactive nature of these strategies; that is, participants could not participate in more than one program option. This interaction is accounted for in the calculation of achievable potential. Application of economic screens shows all three C&I options are cost-effective at the \$98/kW-year threshold, while, for the residential sector, only the CPP option passes[17] the economic criteria. Based on the expected levels of program participation and event participation, 170 MW of the total economic potential from all options is expected to be achievable in the Rocky Mountain Power territory, which is equivalent to roughly 2% of the territory peak. In 2006, the average reduction provided by Rocky Mountain Power Energy Exchange was 2.5 MW; therefore, 167.5 MW of potential is remaining for PacifiCorp to acquire.

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[17] CPP Residential includes commercial customers with less than 30 kW of demand due to similarities in technology required for implementation and delivery synergies.

Table 7. Class 3 DSM: Rocky Mountain Power Territory Technical, Economic, and Achievable Potential (MW in 2027)

Sector	Technical Potential	Economic Potential	Achievable Potential	Achievable as % of 2027 Peak
Residential	691	585	28	1%
Commercial	791	801	45	1%
Industrial	1,329	1,329	96	4%
Irrigation	---	---	---	---
Total	**2,811**	**2,715**	**170**	**2%**

Note: Individual results may not sum to total due to rounding

In the Pacific Power service territory, the technical potential is lower than for Rocky Mountain Power, owing mainly to the territory's smaller industrial load. Because of Pacific Power's avoided cost of $58/kW-year, CPP for commercial, RTP, and demand bidding are the only options that pass the economic screen; curtailable tariffs, CPP for residential, as well as TOU rates, are screened out, as they have relatively high hardware costs relative to the impacts provided by each participant. Achievable potential shows the most opportunity in the industrial sector, but the overall impact on Pacific Power peak is expected to be nearly zero. Of the 21 MW of achievable potential, Pacific Power currently has approximately 1.5 MW of demand reduction from the Energy Exchange program.

Table 8. Class 3 DSM: Pacific Power Territory Technical, Economic, and Achievable Potential (MW in 2027)

Sector	Technical Potential	Economic Potential	Achievable Potential	Achievable as % of 2027 Peak
Residential	498	---	---	---
Commercial	430	333	15	0%
Industrial	89	76	6	3%
Irrigation	---	---	---	---
Total	**1,016**	**410**	**21**	**0%**

Note: Individual results may not sum to total due to rounding.

Please note that the curtailable tariff program modeled here does not include load reductions from utilizing backup generators (see Section 5, Supplemental Resources); if PacifiCorp develops a program with this curtailment option, the 43 MW of potential (both Rocky Mountain Power and Pacific Power) for curtailment could reasonably double.

Resource Costs and Supply Curves

Costs for capacity-focused program options vary significantly in types of cost and their amounts. 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 further fall into two categories: those varying by the number of customers (e.g., hardware costs) and those varying by kW reduction (primarily incentives).

Where possible, costs estimates were developed for each program option based on comparable programs. In certain cases, this specificity level was difficult to establish as many utilities do not track or report program costs. For example, development of a new demand response program can be significant for a utility, requiring enrollment, call centers, program management, load research, development of evaluation protocols, changes to billing systems, and marketing. Background research on utilities across the country provided cost estimates ranging from zero to $2 million. In 2002, PacifiCorp paid $317,000 and Portland General Electric (PGE) paid $540,000 in non-hardware expenses to begin TOU programs. In California, program development costs have been significantly higher. Therefore, this analysis assumes a basic program development cost of $400,000. Marketing is another example with widely varying costs, from about $25 per customer to over $5,000, based on interviews with program managers. This analysis conservatively assumes $25 for each new residential participant and $500 for each commercial or industrial participant.

In developing estimates of per-unit costs, program expenses are allocated annually over the expected program life cycle (20 years), then discounted by a real cost of capital (5.1%) to estimate the total discounted cost. The ratio of this value and the average annual kW reduction produces the levelized per-kW cost for each resource. Additionally, attrition rates are used to account for program turnover due to changes in electric service (i.e., housing stock turnover) and program drop-outs. The basic assumption for this analysis is 5%, based on experiences of Rocky Mountain Power. Attrition requires reinvestment of new customer costs, including technology, installation, and marketing. In addition, the analysis assumes a measure life for the installed technology, and all costs are adjusted upward by 15% to account for administrative expenses.[18]

Table 9 displays the per-unit ($/kW-year) costs by service territory for the estimated market potential and displays the results of the economic screen.[19] Although the input assumptions of costs do not vary by service territory, the resulting levelized cost per kW may differ when a significant difference occurs in average per customer loads and impacts.

For Class 1 DSM resources, irrigation load control is estimated to be the least expensive option, with a levelized cost of $47/kW-year and $50/kW-year for Rocky Mountain Power and Pacific Power service territories, respectively. Per-unit resource costs for direct load control for residential air conditioning are estimated at $93/kW-year and $98/kW-year for Rocky Mountain Power and Pacific Power, respectively. This resource does not pass the economic screen in the Pacific Power territory. Direct load control and thermal energy storage in the commercial sector are the highest cost resources, owing mainly to the significant investment requirements in enabling technologies.

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[18] All resource classes in this study include a 15% administrative adder to account for ongoing program expenses.

[19] For capacity-focused resources, achievable potential can vary widely between strategies. Therefore, achievable potential is estimated even for programs that did not pass the economic screen.

Table 9. Class 1 DSM: Levelized Costs and Market Potential (MW in 2027)

Levelized Cost	DLC		Irrigation	Thermal Energy Storage
	RES - AC	Commercial		
Rocky Mountain Power				
Market Potential (MW)	161	1	104	7
Levelized Cost	$93	$138	$47	$153
Base Economic Screen ($98/kW-year)	Pass	- - -	Pass	- - -
Pacific Power				
Market Potential (MW)	26	0	20	2
Levelized Cost	$98	$151	$50	$150
Base Economic Screen ($58/kW-year)	- - -	- - -	Pass	- - -

Service territory supply curves are constructed from quantities of estimated market resource potential and per-unit costs of each resource option. The capacity-focused supply curves, shown in Figure 6 and Figure 7, represent the quantity of each resource (cumulative market MW) that can be achieved at or below the cost at any point. Cumulative MW is created by summing the market potential along the horizontal axis sequentially, in the order of their levelized costs. For Class 1 DSM, the air conditioning DLC program has 170 MW available, and its cost is the second lowest. Its quantity, therefore, is added to the 94 MW of irrigation, showing that, in total, 265 MW of resources are available at prices equal to or less than $98/kW-year. The dotted horizontal lines in the following figures show PacifiCorp's avoided cost of capacity by service territory, representing the cost-effectiveness threshold for various resources options.

Figure 6. Class 1 DSM: Rocky Mountain Power Territory Supply Curve (Cumulative MW in 2027)

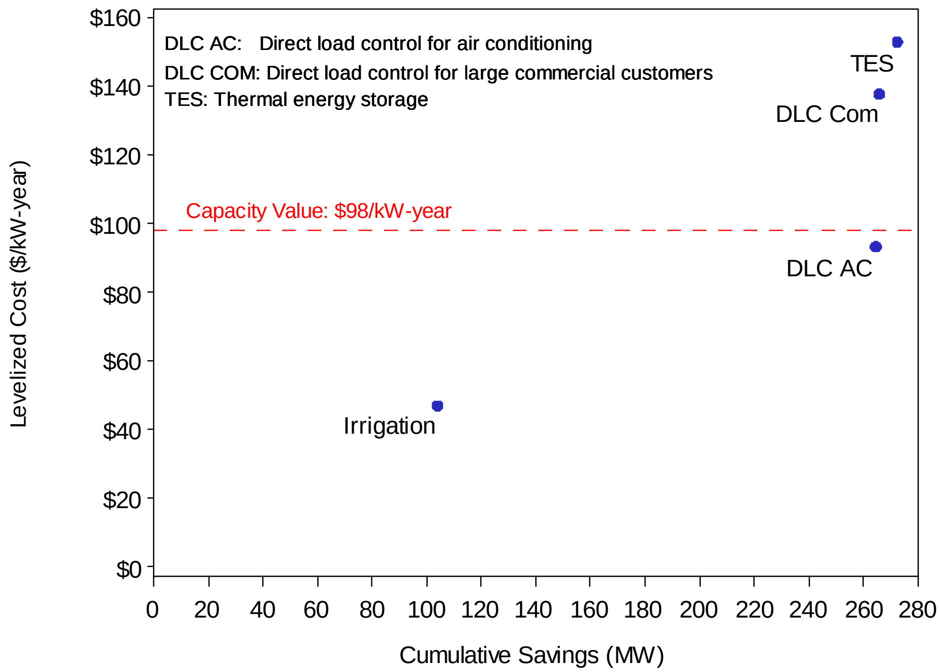
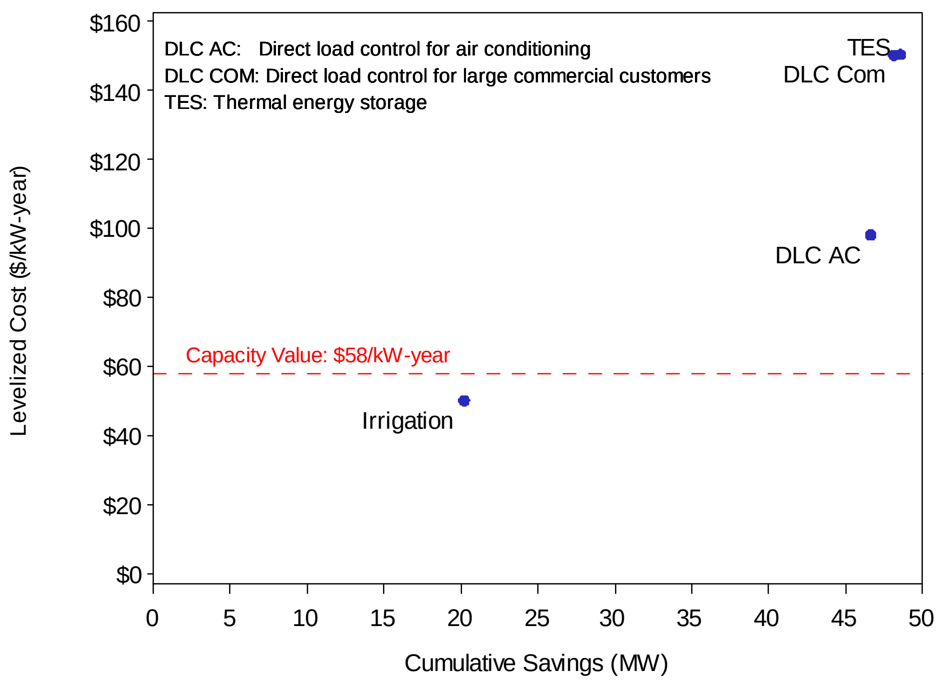


Figure 7. Class 1 DSM: Pacific Power Territory Supply Curve (Cumulative MW in 2027)



For Class 3 DSM resources, the pricing programs for C&I customers are estimated to be the least expensive and to pass the economic screen for both Rocky Mountain Power and Pacific Power territories. RTP ($6/kW-year Rocky Mountain Power, $8/kW-year Pacific Power) and commercial CPP ($12/kW-year Rocky Mountain Power, $33/kW-year Pacific Power) are relatively inexpensive as incentives are not paid. Additionally, these programs are targeted at larger C&I customers (greater than 30kW for CPP and greater than 250 kW for RTP); so the average load reduction is significant. DBB is also cost-effective, at $18/kW-year for both territories. Curtailable tariffs are estimated at $59/kW-year (Rocky Mountain Power) and $61/kW-year (Pacific Power); this program option passes the economic screen in the Rocky Mountain Power territory, but not in the Pacific Power territory.

The residential pricing programs (TOU rates and CPP) are comparatively expensive due to the relatively small load reductions compared to installed technology (meters, smart thermostats for CPP) and ongoing program maintenance costs (communications and administration). TOU programs are reported to experience peak-demand impacts approximately 80% less than CPP programs, therefore leading to significantly higher per-unit costs.

Table 10. Class 3 DSM: Levelized Costs and Market Potential (MW in 2027)

Levelized Cost	Curtailable Tariffs	Demand Bidding	TOU Rates	Critical Peak Pricing		Real Time Pricing
				Residential	C&I	
Rocky Mountain Power						
Levelized Cost	$59	$18	$166	$88	$12	$6
Market Potential (MW)	38	27	11	30	61	14
Base Economic Screen ($98/kW-year)	Pass	Pass	- - -	Pass	Pass	Pass
Pacific Power						
Levelized Cost	$61	$18	$173	$91	$33	$8
Market Potential (MW)	5	10	8	22	9	1
Base Economic Screen ($58/kW-year)	- - -	Pass	- - -	- - -	Pass	Pass

Figure 8. Class 3 DSM: Rocky Mountain Power Territory Supply Curve (Cumulative MW in 2027)

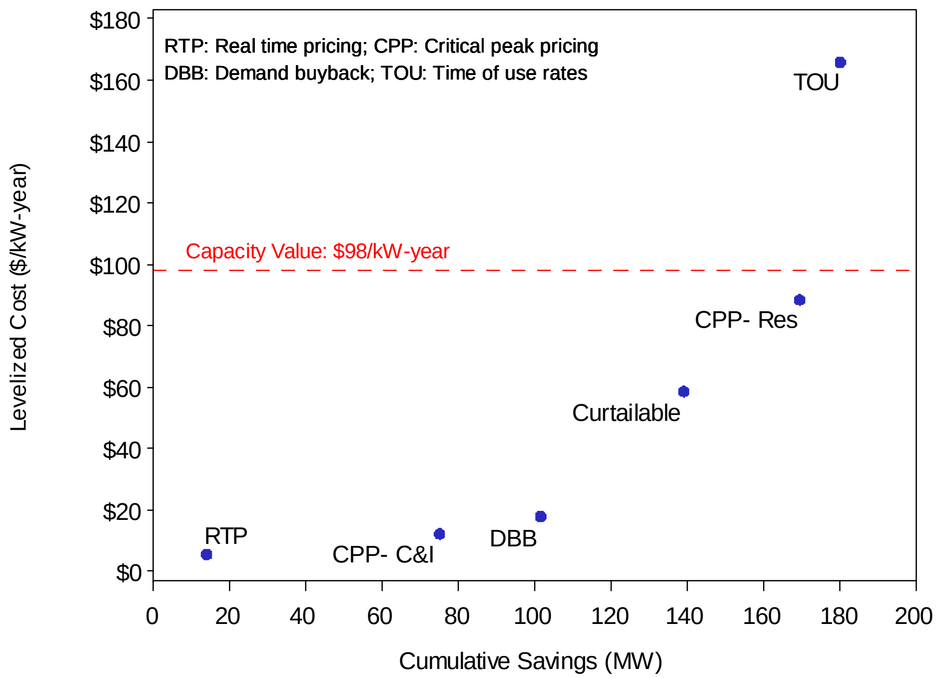
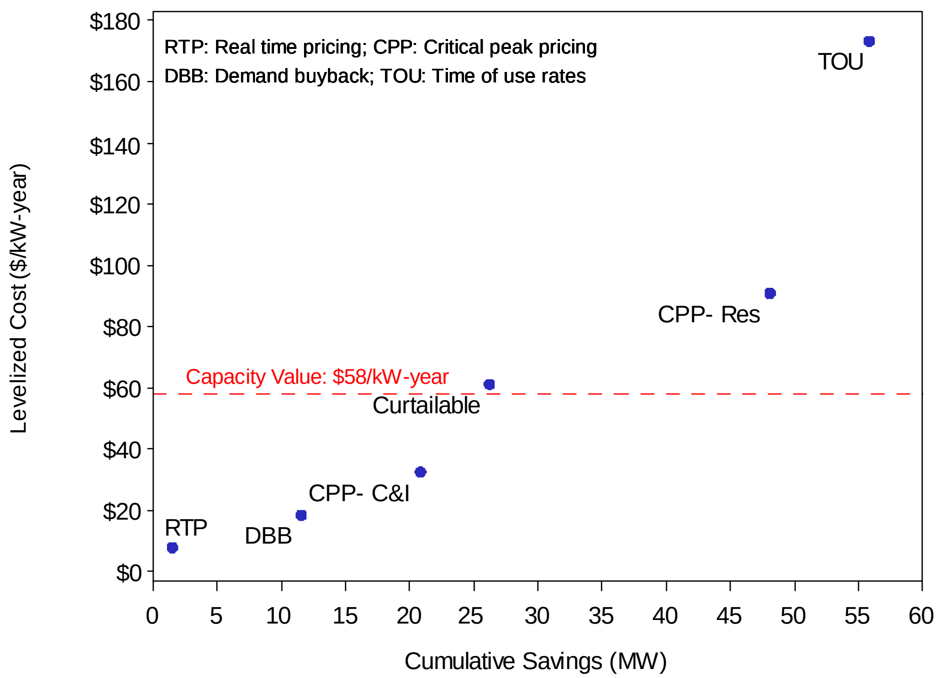


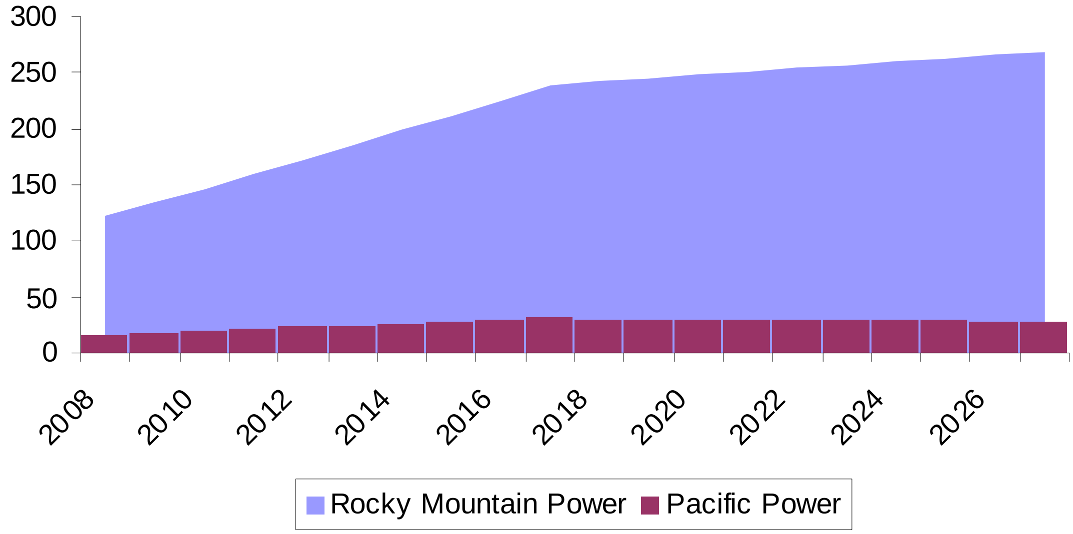
Figure 9. Class 3 DSM: Pacific Power Territory Supply Curve (Cumulative MW in 2027)



Resource Acquisition Schedule

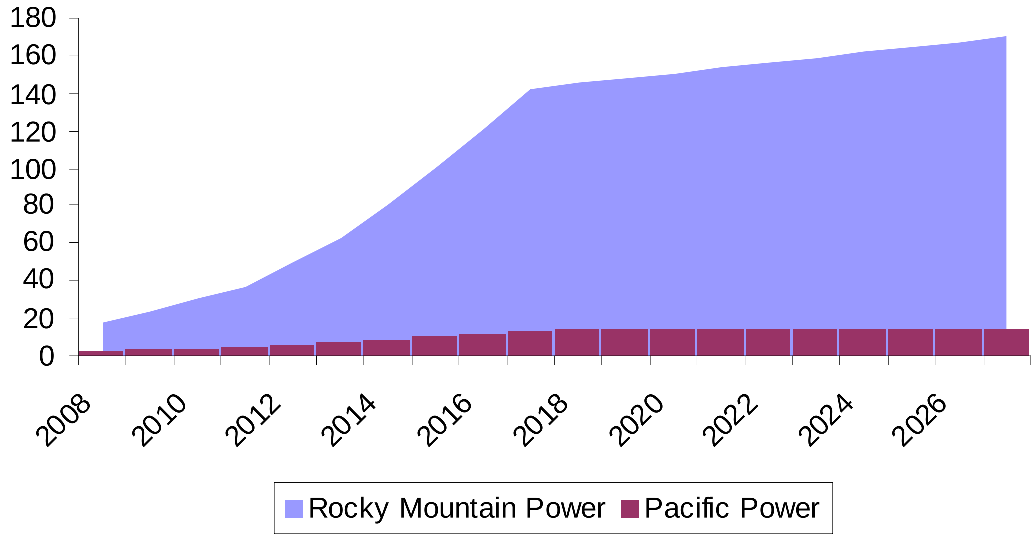
The rate of acquisition for Class 1 and Class 3 DSM program options are shown graphically in Figure 10 and Figure 11. Each program option has its own ramping rate; the general logic is that it requires ten years to grow a new program from inception to full potential and the first few years have relatively slow growth. After year ten, the program levels increase at the rate of sales growth, by sector. For programs PacifiCorp currently has under contract (irrigation, DBB, and DLC air conditioning), ramping begins with the existing program quantity under contract. Therefore, the Class 1 DSM schedule starts with more than 100 MW, and grows steadily until 2018, when the increases are based on the forecast customer segment rates of load growth.

Figure 10. Class 1 DSM: Acquisition Schedule for Achievable Resource Potential by Year and Territory



For Class 3 DSM, the current DBB program (Energy Exchange) has an average of 4 MW achieved during each event; therefore, the initial year starts above this quantity. Because the majority of the potential is for CPP and RTP for C&I, the quantity under contract rises at an increasing rate until 2017, when the increases are based solely on load forecast increases.

Figure 11. Class 3 DSM: Acquisition Schedule for Achievable Resource Potential by Year and Territory



Resource Potential under Alternative Scenarios

Two key areas provide the majority of uncertainty in this analysis: avoided cost of capacity, and levels of customer acceptance driving achievable potential. The results provided above use base-case economic assumptions of the value of capacity and expected quantity of program participation; this section uses variation in each of those factors, providing a range around achievable potential. The economic scenarios (shown in Table 11) are based on PacifiCorp market price forecasts to calculate the high scenario (48% above the base case) and low scenario (30% below the base case). The high achievable scenario assumes 50% more incentives than the expected case and an increased rate of achievable potential, which varies slightly among programs. For the C&I sectors, expected case results, as discussed above, are based on survey results of PacifiCorp customers' preferences for each program type. The high achievable case is based on customers that indicated positive sentiments for a program description.[20] Background research was also consulted to ensure results were within a reasonable range.

As shown in Table 11, the Rocky Mountain Power territory can expect 265 MW of Class 1 DSM achievable potential under the base economic scenario, from irrigation and DLC air conditioning. For the high economic scenario, potential increases to 266 MW because large commercial direct load control becomes cost-effective at this threshold. For the low economic scenario, only irrigation is economically viable, so the achievable potential falls to 104 MW. For the high achievable potential scenario, potential falls to 125 MW, representing only the irrigation potential, because air conditioning DLC incentives are increased, and the program is not cost-effective for the base and low economic scenarios (with a $146/kW threshold).

[20] It is assumed all customers stating "very positive" sentiments to a program type and half of those responding "somewhat positive" are likely to participate with the increased incentives quantities.

For Rocky Mountain Power Territory's Class 3 DSM resources with expected quantities of achievable potential, the base and high economic scenarios have 170 MW, which includes curtailable tariffs, demand bidding, both residential and C&I CPP, and RTP; the residential CPP option does not pass the low threshold. With the high achievable scenario, an additional 133 MW are provided by these same pricing programs, although the low economic scenario excludes the curtailable tariffs program and CPP for residential customers (with a threshold of $68/kW-year)

For Pacific Power Class 1 DSM resources under expected levels of achievable potential, irrigation is cost-effective under the base and high economic scenarios. For the high achievable scenario, the cost of irrigation rises to $67/kW-year and is therefore only cost-effective under the high economic scenario threshold of $85/kW-year. For Class 3 DSM resources under expected rates of achievable potential, all four C&I options (curtailable tariffs, demand bidding, CPP, and RTP) are viable under the high economic threshold of $85/kW-year, but curtailable tariffs, with a levelized cost of $61/kW-year does not pass the base or low economic scenario. For the high achievable scenario, demand bidding, commercial CPP, and RTP are included for all economic scenarios.

Table 11. Economic and Achievable Scenarios: Achievable Potential (MW in 2027)

		Economic Scenario MW		
		Base	**High**	**Low**
Rocky Mountain Power				
($/kW-year decrement)		*$98*	*$145*	*$68*
Class 1 DSM	Expected Achievable	265	266	104
	High Achievable	125	350	125
Class 3 DSM	Expected Achievable	170	170	139
	High Achievable	303	303	177
Pacific Power				
($/kW-year decrement)		*$58*	*$85*	*$40*
Class 1 DSM	Expected Achievable	20	20	---
	High Achievable	---	24	---
Class 3 DSM	Expected Achievable	21	26	21
	High Achievable	33	33	33

Class 1 DSM Resource Results by Program Option

Direct Load Control Results

Direct load control (DLC) programs are designed to interrupt specific end-use loads at customer facilities through utility-directed control. When deemed necessary, the utility is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers do not have to pay for the equipment or installation of control systems and are given incentives that are usually paid through monthly credits on their utility bills. For this type of program, receiver systems are installed on the customer equipment to enable communications from the utility and to execute controls. Historically, DLC programs have been 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.[21]

Recently, DLC of air conditioning has emerged as the most common load management program type. The recent FERC report[22] indicates, as of last summer, 234 entities offer DLC programs, and most of these offer residential air conditioning load control. In addition to reviewing meta-studies[23,24] on DLC, the research team conducted in-depth interviews and researched many key utility programs, including those sponsored by MidAmerican Energy Company, Sacramento Municipal Utility District, Southern California Edison, Pacific Gas and Electric, Puget Sound Energy, Austin Energy Power, Austin Energy, Consolidated Edison, E.ON US, Long Island Power Authority, Idaho Power, Xcel-MN, Wisconsin Public Service, Florida Power and Light, and Dairyland Cooperative.

This analysis covers residential and commercial direct load control programs and reviewed multiple types of available end uses. This section has analyzed three primary program options: (1) air conditioning only; (2) air conditioning with water heating; and (3) large commercial.

Air Conditioning Only (Residential and Small Commercial)

Currently, PacifiCorp has approximately 89 MW of load curtailment under contract from its Utah Cool Keeper program. Like many other national programs, it is targeted at the residential and small commercial customer classes (with less that 7.5 tons of cooling[25]), and only central cooling systems (including heat pumps) are eligible. On average, PacifiCorp called events totaling 35 to 40 hours of curtailment per year, which is consistent with most of the researched utility programs mentioned above. The combination of these factors results in the estimate of technical potential: 992 MW (Rocky Mountain Power) and 298 MW (Pacific Power), which includes the quantity of potential currently under contract.

To estimate the amount of market potential[26] available for this program, event participation is assumed to be a combination of a standard 50% duty cycling strategy and 92% participation during actual events (based on PacifiCorp's estimates of opt-outs and non-functioning hardware, which is are consistent with other utilities). The factor with the most uncertainty is the expected rate of program sign-up. Across the country, participation rates vary widely, from as little as 1% to 40% of residential customers. The lower participation rates are generally for the newer

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21 Typically, penalties are associated with non-compliance or opt-outs

22 FERC, Assessment of Demand Response and Advanced Metering, August 2006

23 DOE, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them, Report to Congress, February 2006

24 E Source, EDRP-F-8, Best Practices in Residential Direct Load Control Programs, November 2006.

25 To assess the characteristics of customers with cooling systems less than 7.5 tons, given PacifiCorp's customer information system database, customers with a maximum demand of less than 30 kW during the summer were assumed to be eligible.

26 To reiterate, market potential is estimated for all strategies, but only those making it through the cost-effectiveness screen are shown in the achievable summary of Table 5 through Table 8.

programs and the higher participation rates for the older programs, but there are some interesting exceptions to this rule. E.ON US (LG&E/Kentucky Utilities) only started its DLC program in 2000 and has already signed up 37% of its residential customers. participation rate for national programs is between 15% and 20% of all residential customers,[27] which translates into 20% to 30% of eligible customers (those with central air conditioning, which is the load basis for this program). For example, Rocky Mountain Power runs an air conditioning DLC program (Cool Keeper) in Utah, which currently has 11% of residential customers, but 30% of eligible customers on the program (those with central cooling). Therefore, this analysis assumes there is potential to sign up 40% of eligible customers (an additional 10% beyond currently achieved levels) in Utah and 25% in other states (to be consistent with other national program achievements), but only 1% of small commercial customers, based on the experience of PacifiCorp and other national utilities and supported by C&I survey.

Table 12 below shows the technical and market results for Rocky Mountain Power and Pacific Power territories, by customer class. Due to high cooling loads, the largest potential for air conditioning is in Rocky Mountain Power with 160 MW (2% of 2027 territory peak), which includes the achievements of the Cool Keeper program (i.e., 71 MW of potential remain for acquisition). In the Pacific Power territory, there is an additional 26 MW of potential (<1% of 2027 territory peak).

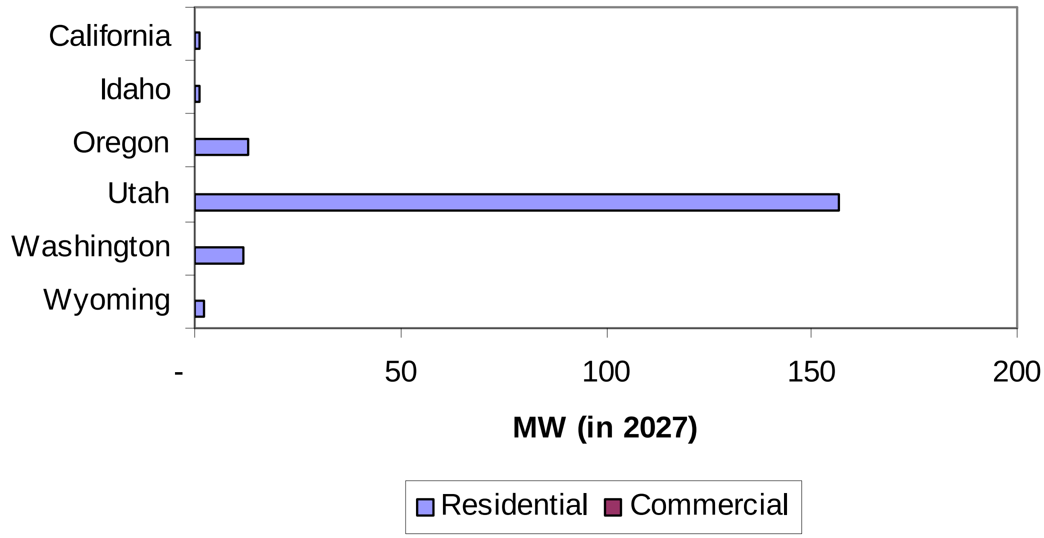
Table 12. DLC Air Conditioning: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	880.5	160.0	7.9%	226.9	26.1	1.3%
Commercial	111.4	0.5	0.0%	70.7	0.3	0.0%
Industrial	---	---	---	---	---	---
Irrigation	---	---	---	---	---	---
Total	**991.9**	**160.5**	**2.0%**	**297.7**	**26.4**	**0.5%**

Figure 12 displays the state-specific results, with the residential sector in Utah dominating the potential with over 150 MW by 2027. These results incorporate PacifiCorp's forecast of increases in load expected in Utah, followed by Oregon and Washington, with 13 MW available each.

27 Most sources provide participation only for a number of residential customers. This study assumes an average of 75% saturation of central cooling systems for the researched programs.

Figure 12. DLC Air Conditioning: Market Potential by State (MW in 2027)



In terms of costs, one of the historically important factors is the choice of technology type: thermostats (which raise the temperature set-point) or switches (which utilize a duty cycling strategy). While equipment costs can vary considerably, the price differences between two-way thermostats and simple one-way switches are diminishing as technology costs fall, although installation costs remain significantly different. A range of other issues emerge in choosing the appropriate technology for a given program, including selection of a communications medium (FM, paging, other) and the length of the control period. Installed hardware costs range from about $150 for a simple switch to $450 for a two-way thermostat. This study assumes a one-way switch (similar to the Utah Cool Keeper Program) at a cost of $175.

Incentives utilities offer to customers to participate in these programs vary widely, from only the free programmable thermostat to a 15% discount on customers' summer electric bills, which can sum to $50-$60 annually for many participants. The median customer incentive across all researched programs is approximately $25 annually. Currently PacifiCorp pays $20/year for residential customers and $40/year for small commercial customers; these incentives are used in the analysis. Additional costs are assessed for this program, including $25 per new customer of marketing, $7 for each existing customer for communications, replacement of technology every ten years, $400,000 for program start-up, and an attrition rate (requiring reinvestment of new-customer costs) of 7% based on 5% rate of electric service turnover and 2% program removals. Detailed assumptions are provided in Volume II, Appendix B.

By service territory, Table 13 displays the quantity of market potential for DLC resources and the resulting costs based on the factors described above. The high achievable potential scenario assumes an additional 10% of residential customers and 0.5% commercial customers would sign up for the program. All high achievable potential scenarios assume a 50% increase of incentives. The final three columns of the table display those economic screens that the program option passes.

In the Rocky Mountain Power territory, the base levelized cost is $93/kW-year, which passes the base and high economic screens (thresholds of $98/kW-year and $145/kW-year, respectively). The high achievable scenario results in 225 MW of savings, but a resulting cost of $121/kW-year, which passes only the high economic screen. In the Pacific Power territory, neither achievable scenario passes an economic screen. The base cost is slightly higher ($98/kW) for Rocky Mountain Power due to lower average size of cooling loads; high achievable results in an additional 11 MW of potential at a cost of $128/kW-year.

Table 13. DLC Air Conditioning: Levelized Costs and Scenarios

	MW Potential	Levelized Cost $/kW-Year	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	161	$93	---	Pass	Pass
High Achievable	225	$121	---	---	Pass
Pacific Power					
Expected Achievable	26	$98	---	---	---
High Achievable	37	$128	---	---	---

Residential Water Heater and Other End-Use Programs

This study conducted research into other end uses commonly controlled by DLC programs. There are several program examples of utilities combining other end uses with air conditioning to offer multiple end-use DLC programs. By far the most common add-on is water heating, but Florida Power and Light also covers residential electric space heating and pool pumps in its residential *On Call* program. Hawaii Electric Company has one of the few water heating-only DLC programs offered by an investor-owned utility, called *Energy Scout*. A number of smaller water heater pilot efforts also have been initiated around the country; Midwestern rural co-ops in particular have embraced water heater control as a means of engaging customers in helping to reduce peak system (winter) loads.

The most common program option (with examples from utilities such as Xcel Energy, E.ON US, and Florida Power & Light) is to offer customers the opportunity to add hot water heating control to their air-conditioning control program. This study estimates the potential for this combination using the same air conditioning assumptions shown above, but adding water heat as an option. The installed costs for water heat control are assumed to be the same as the air-conditioning control, as a similar one-way switch would be used. The technical potential for the water heating portion includes only those customers with both central cooling and electric hot water heating.

As expected, the results in Table 14 show that adding hot water heating leads to an increase in the amount of market potential, yet raises the average levelized cost of the program significantly as the hot water heaters have the same costs as air-conditioning, but provide less per-unit demand reductions. This is particularly true in the summer, when the value of capacity is highest for PacifiCorp. Because these programs are substitutes (i.e., they would not be run at the same time), the summaries in Table 5 and Table 6 do not include this option. It should be noted that continuing declines in the saturation of electric hot water heating in PacifiCorp territory would lower the potential for this program option.

Table 14. DLC Air Conditioning and Water Heat: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	168	$106	---	---	Pass
High Achievable	235	$138	---	---	Pass
Pacific Power					
Expected Achievable	42	$169	---	---	---
High Achievable	59	$219	---	---	---

Finally, research was conducted on the plausibility of running an electric space heating program, with the primary finding that electric space heating DLC programs are rare, and there is low saturation of electric space heating in the PacifiCorp territory. The primary programs reviewed were pilots conducted by PGE and Puget Sound Energy in 2003; neither program was continued. Generally, concerns about health and safety issues emerge with controlling heating systems, and, across the country, the share of homes with electric heating is falling. Therefore, due to lack of successful program examples and the focus on summer capacity needs, this study does not model this option.

Commercial/Industrial DLC Programs

Direct control of C&I customers is an enticing option for utilities due to the large size of loads and the reliability of direct control. Yet, this option requires significant technological investment in coordination with the existing energy management systems (EMS), and is generally not favored by customers. (This program option precludes the use of backup generators. Please see the analysis of dispatchable standby generation in Section 5.)

Recently, the International Energy Agency (IEA) released a study that included a survey of 40 major utilities with capacity-focused programs, revealing that fewer than one-quarter of those surveyed offered DLC programs to their commercial customers. Participation rates were extremely low, and the majority of these were offered to small commercial customers (which is covered in the air-conditioning program above).[28] Utilities offering programs to large C&I customers include: Florida Power and Light, Xcel Energy, Otter Tail Power and Light, Madison Gas and Electric, Wisconsin Electric, and Wisconsin Public Service.

Although the program history is limited, this study estimates potential for large commercial customers, requiring a size threshold of 250 kW to increase likelihood of existing EMS systems. The following end uses are assessed by customer segment: cooling, hot water, lighting, plug load, and refrigeration. It is assumed this program option would be called at similar frequency to

[28] R. Gunn, “North American Demand Response Survey Results” (Association of Energy Services Professionals, Phoenix, AZ, February 2006).

the air-conditioning program: approximately 40 hours per summer. Technically, only a small portion of the total end-use loads could be curtailed; the technical assumptions can be found in Volume II, Appendix B. The combination of these factors results in an estimate of technical potential of 136 MW and 47 MW for Rocky Mountain Power and Pacific Power territories, respectively.

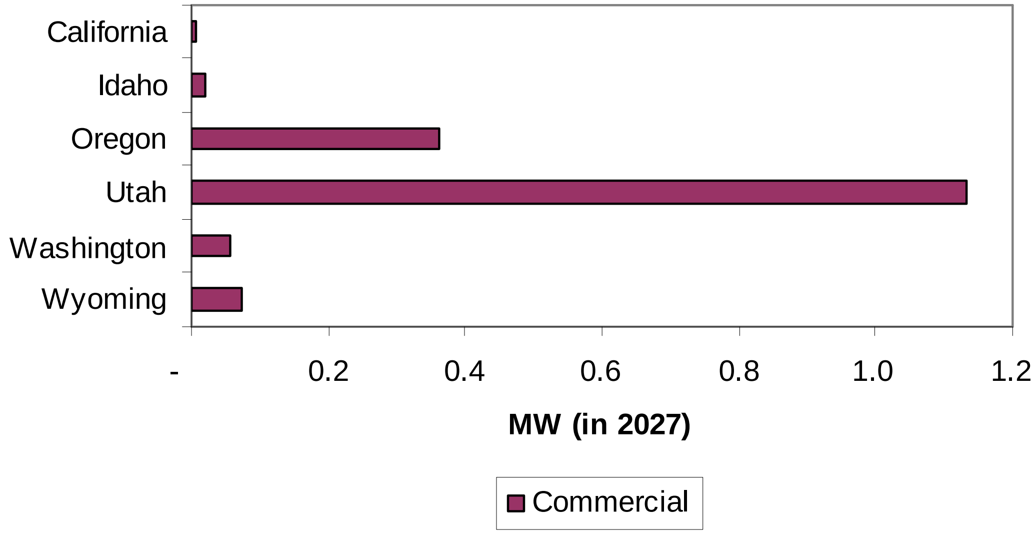
To estimate the technical potential quantity available in the market, the most uncertain factor is program participation. Findings from the IEA survey indicated C&I DLC program participation rates are generally quite low (less than 1% of load), excepting Xcel Energy and Otter Tail Power, which achieved participation rates greater than 10%, at a cost of about $250/kW. The C&I survey conducted for this study indicates essentially no customers would choose DLC if given another program option. This program option received the most negative feedback. A large fraction of respondents reported they are very hesitant to let the utility have control over their facility operations. Therefore, this study assumes a program participation rate of 1%. Event participation is assumed at 90% based on other national programs.

Table 15 displays the technical and market results for the Rocky Mountain Power and Pacific Power territories. Although approximately 136 MW and 47 MW are technically available for the Rocky Mountain Power and Pacific Power territories, there is essentially no market potential for this program option due to a lack of interest among customers. As shown in Figure 13, the majority of this small potential is available in Utah and, to a lesser extent, Oregon.

Table 15. DLC Large Commercial: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	---	---	---	---	---	---
Commercial	136.2	1.2	0.0%	47.1	0.4	0.0%
Industrial	---	---	---	---	---	---
Irrigation	---	---	---	---	---	---
Total	**136.2**	**1.2**	**0.0%**	**47.1**	**0.4**	**0.0%**

Figure 13. DLC Large Commercial: Market Potential by State (MW in 2027)



In terms of costs, the analysis estimates interfacing with existing EMS controls for each end use, reflecting a hierarchy of measures: 1) cooling, 2) lighting, 3) hot water, 4) process, and 5) plug load. Controls are assumed to last ten years. Customer incentives are assumed at $6/kW per month ($72/kW-year) based on the need to pay customers relatively high incentives to have direct control over loads. Attrition rates are assumed to be 10%, based on a 5% change of electrical service and a 5% removal rate based on commercial customer concerns about DLC of end uses. Marketing costs per new participant are assumed to be $500, and program development would cost $400,000 for internal labor and technology costs.

Table 16 shows that with an expected cost of $138/kW-year (Rocky Mountain Power) and $151/kW-year (Pacific Power), this program option passes only the high economic screen. With a high cost of $148/kW-year and $152/kW-year (Rocky Mountain Power and Pacific Power, respectively), this option passes none of the economic scenarios.

Table 16. DLC Large Commercial: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	1	$138	---	---	Pass
High Achievable	6	$148	---	---	---
Pacific Power					
Expected Achievable	0	$151	---	---	---
High Achievable	2	$152	---	---	---

Irrigation

A program targeting irrigation is an ideal option to reduce summer peak due to the coincidence of irrigation pumping with mid-afternoon summer peaks. PacifiCorp's current irrigation load control program in Idaho is a scheduled control program; customers subscribe in advance for specific days and number of hours when their irrigation systems will be turned off. Load management is executed automatically based on a pre-determined schedule set through a timer device. Although a total of 100 MW of irrigation loads are contracted for management under this control program, less than half are available at any time due to the alternating schedules of program participants. In the Northwest, the Bonneville Power Administration (BPA) has run a pilot irrigation program (on a dispatched rather than scheduled basis), and Idaho Power has implemented a program similar to PacifiCorp's scheduled control program. In 2007, PacifiCorp began piloting a limited-scope 45 MW dispatchable program in addition to its scheduled control option. Presuming it will be successful, this analysis assumes that, in the future, half of the participants will sign up for the dispatchable control option and half will sign up for the scheduled control option.

Technically, it is assumed all irrigation loads are eligible for this program, excepting half of the Oregon load (which is horizontal pumping and not suitable for this offering). This results in a technical potential of 308 MW (Rocky Mountain Power) and 108 MW (Pacific Power).

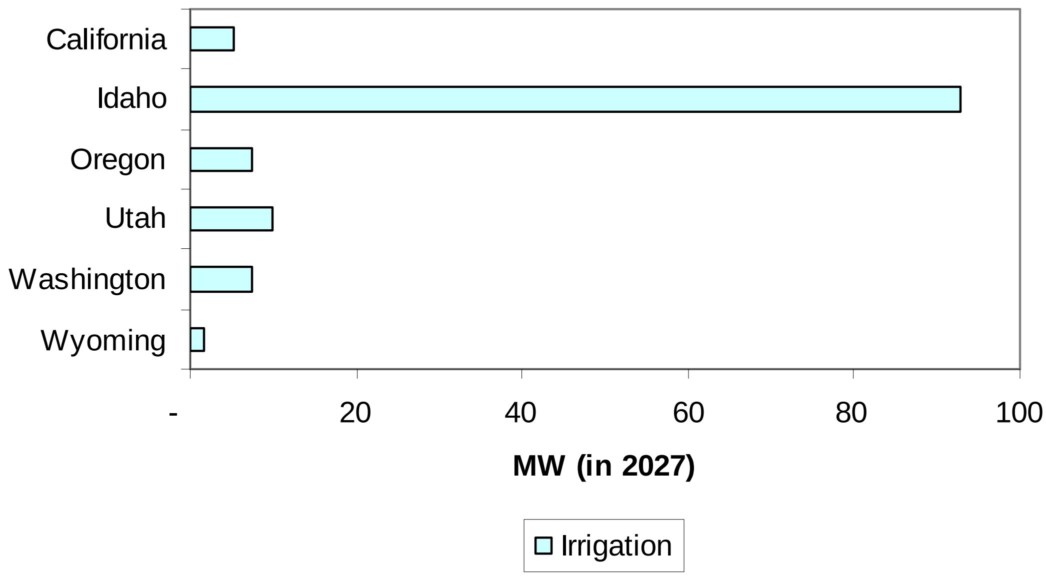
In terms of program participation, both PacifiCorp's and Idaho Power's scheduled control option programs have had solid participation rates: 35% and 25% of eligible load, respectively. This analysis assumes PacifiCorp can increase the participation rate in Idaho to 50% and will reach 25% in other states, where pumps tend to be smaller and loads are distributed across more customers. Assuming one-half of participants are on a scheduled control program, during any one event, only 75% of the load will be available. These factors lead to a market potential estimate of 20 MW for Pacific Power (<1% of 2027 territory peak). For Rocky Mountain Power, 104 MW is available, which includes the 81 MW of expected 2007 achievements (78 MW in Idaho and 3 MW in Utah).

Due to load distribution the majority of this is expected to come from Idaho (93 MW). The PacifiCorp forecasts of irrigation loads expect an overall reduction of approximately 10% over the next 20 years, which is accounted for in the estimate of potential in 2027.

Table 17. Irrigation: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	- - -	- - -	- - -	- - -	- - -	- - -
Commercial	- - -	- - -	- - -	- - -	- - -	- - -
Industrial	- - -	- - -	- - -	- - -	- - -	- - -
Irrigation	308.3	104.2	21.3%	107.9	20.2	8.1%
Total	**308.3**	**104.2**	**1.3%**	**107.9**	**20.2**	**0.4%**

Figure 14. Irrigation: Market Potential by State (MW in 2027)



Costs for the irrigation program include $400,000 for upfront program costs, $1,000 for installed technology with a life of seven years, $500 for marketing to new customers, and $10/kW for ongoing maintenance and communication systems based on Rocky Mountain Power's experience. Although PacifiCorp currently pays $11/kW-year for incentives (2006 program year), participation level assumptions are based on a higher incentive amount of $20/kW-year in recognition that greater penetration will require higher incentives and the emergence of the dispatchable control option is expected to increase the value of the control to PacifiCorp.

Table 18 displays the resulting levelized costs for the irrigation. With an expected cost of $47/kW-year and $50/kW-year (Rocky Mountain Power and Pacific Power territories, respectively), this program option passes all economic screens. The high achievable scenario assumes a 20% increase in participation and a 50% increase in incentives. With a high achievable cost of $67/kW-year and $70/kW-year (Rocky Mountain Power and Pacific Power, respectively), irrigation in the Rocky Mountain Power territory passes all economic scenarios.

Table 18. Irrigation: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	104	$47	Pass	Pass	Pass
High Achievable	125	$67	Pass	Pass	Pass
Pacific Power					
Expected Achievable	20	$50	- - -	Pass	Pass
High Achievable	24	$70	- - -	- - -	Pass

Thermal Energy Storage

For C&I customers, it is possible for cooling TES systems that produce ice during off-peak periods, which is then used during the on-peak periods to cool buildings during pre-specified times (typically six hours per day, from April to October).[29]

Few investor-owned utilities currently offer TES programs to their customers. Information on three such programs was obtained as a result of discussions with a major manufacturer of TES equipment. PG&E and SCE just initiated RFP processes for TES programs in early 2007, and very little information is available about the status of these programs. Xcel Energy (Minnesota) has offered incentives for TES systems in one form or another for about 20 years, currently as part of its Custom Solutions energy-efficiency program, with modest program results (one or two installations each year).

TES systems require rooftop cooling units, typically found on large commercial sites. Therefore, this analysis assumes only those commercial sector customers with greater than 30 kW in total site demand would be eligible for participation, and the technical feasibility of participating is reduced to account for only customers with DX cooling units. Program participation is assumed to be quite low (2.5% of eligible load) based on the experience of Xcel Energy and SCE.

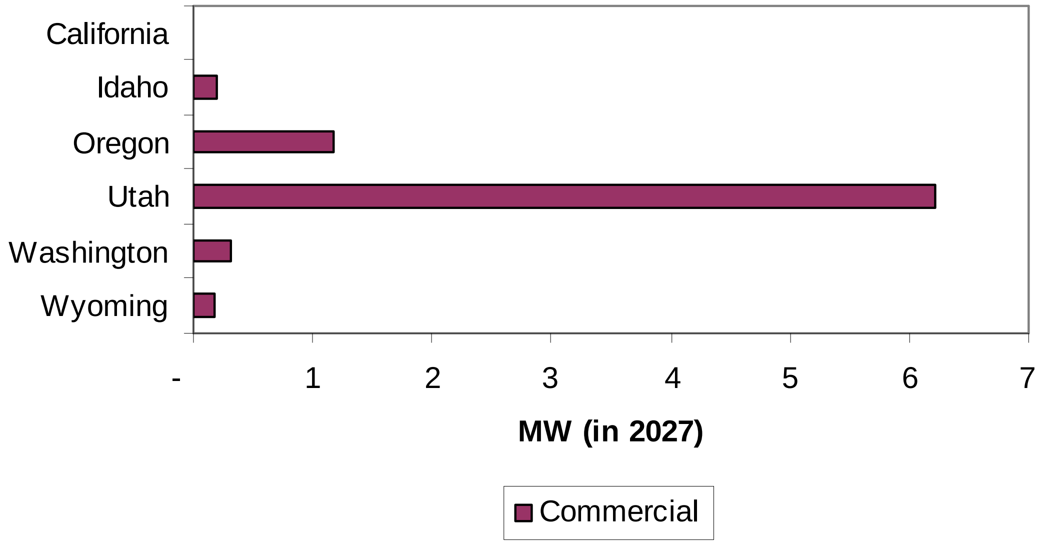
Table 19 displays the results for TES for the Rocky Mountain Power and Pacific Power territories. Technically, the Rocky Mountain Power territory has 264 MW of potential, but, due to low participation rates, it is likely only 6.6 MW are available (representing less than 1% of the 2027 territory peak). Similarly, the Pacific Power territory has 60 MW of potential but only 1.5 MW of market potential. As shown in Figure 15, the majority of the potential is in Utah, which is further driven by high expected growth in the commercial sector.

Table 19. Thermal Energy Storage: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	---	---	---	---	---	---
Commercial	263.5	6.6	0.2%	60.4	1.5	0.1%
Industrial	---	---	---	---	---	---
Irrigation	---	---	---	---	---	---
Total	**263.5**	**6.6**	**0.1%**	**60.4**	**1.5**	**0.0%**

[29] At this time, there is a commercialized application for small commercial applications (5-20 tons of cooling) for which two pilot programs exist in the country. Due to lack of commercial history and narrow applicability in PacifiCorp territory, a residential option was not considered at this time.

Figure 15. Thermal Energy Storage: Market Potential by State (MW in 2027)



Thermal energy storage is a technology-intensive option as units must be retrofitted to produce and store ice for on-peak cooling. Costs can vary significantly based on the installation's size, therefore, estimates of initial costs range from $600 to $1,500 per ton of adjustments.[30] This study utilizes the low end of this range ($600) based on a proprietary bid PacifiCorp received from a supplier with corroborating costs. Other cost factors include technology replacement due to normal operating life (17 years) and an annual participant attrition rate of 5% due to changes in electrical service.

Due to the lack of certainty around the level of program participation, Table 20 displays an estimate of high achievable potential, which assumes a doubling of participation may be possible (5%), resulting in 13 MW in Rocky Mountain Power and 3 MW in Pacific Power territories. The per-unit costs actually drop in both cases because there is no incentive and fixed costs are spread among a larger number of participants. Despite favorable cost assumptions, this program option does not pass an economic screen for any of the scenarios at this time.

Table 20. Thermal Energy Storage: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	7	$153	---	---	---
High Achievable	13	$151	---	---	---
Pacific Power					
Expected Achievable	2	$150	---	---	---
High Achievable	3	$148	---	---	---

30 California Energy Commission *Technical Options Guidebook*. 2003

Class 3 DSM Resource Results by Program Option

Curtailable Tariffs Program

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

Customers are generally not paid for individual events, but 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 the greater of a set percentage (e.g., 15%-20%) 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.

The International Energy Agency survey[31] of 40 utilities' capacity-focused programs revealed that slightly more than half of utilities surveyed offer curtailable or interruptible[32] rate programs to their C&I customers. Utilities offering programs included almost all the major utilities in California, Illinois, Indiana, Iowa, Minnesota, and Wisconsin as well as a variety of other utilities, including Allegheny Energy, Colorado Springs Utilities, Hydro Quebec, and Kansas City Power and Light. Further research for this study focused on five utilities that had previously been identified as having large program impacts utilities: Xcel Energy, MidAmerican Energy Company, Minnesota Power, Alliant Energy, and Commonwealth Edison. Most utilities require minimum demand reductions to be eligible for the programs, ranging from 50 kW for Xcel Energy, up to the more typical level of 250 kW for MidAmerican Energy Company. Currently, PacifiCorp has a rate structure for its largest industrial accounts that allows curtailment during utility events, but this analysis does not include the load of these "special accounts" and therefore does not include its impact.

In this study, it is assumed C&I customers with a monthly demand of at least 250 kW would be eligible for such a program. Technical potential is estimated by customer segment, based on detailed engineering audits of demand response potential of C&I customers in California, which provides the best data available in the region and can be used in PacifiCorp's territory due to similarities in equipment, such as compressor and HVAC systems. As California does not allow backup generators to be used in its load management programs, the technical potential provided is for load reductions only.

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[31] R. Gunn, "North American Demand Response Survey Results" (Association of Energy Services Professionals, Phoenix, AZ, February 2006).

[32] Interruptible rate programs are those targeting the largest customers (usually greater than 1MW) and receiving a rate discount. Currently, PacifiCorp has several large accounts on this type of agreement.

The survey of PacifiCorp's C&I customers undertaken for this report indicated that customers were receptive to this program option, likely due to the incentive, which is paid regardless of curtailment events. The concerns about the program regarded not design but rather specific business constraints that made participation difficult. The survey results were used to estimate program participation, with an overall weighted average participation rate of 13%, ranging from 0% for segments such as health, lodging, and petroleum manufacturing, to 20%-25% for restaurants, schools, and offices.

Table 21 shows the Rocky Mountain Power territory has over 500 MW of technical potential in the C&I sectors and 38 MW of market potential, totaling 0.5% of the Rocky Mountain Power territory's 2027 peak load. The Pacific Power territory has only 70 MW of technical potential in the C&I sectors due to the relative lack of customers greater than 250 kW and slower growth in load forecasts, resulting in 5 MW of market potential and representing 0.1% of the Pacific Power territory's 2027 peak load. These results are expected from load reductions only; yet, in many utility programs (excluding those in California), customers are allowed to use backup generators to meet curtailment requirements. Therefore, given national program experience, load reductions would be expected to double if backup generators were included as an option for customer participation (see Section 5, Supplemental Resources, for the analysis of backup generators).

Table 21. Curtailable Tariff Program: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	---	---	---	---	---	---
Commercial	150.1	17.6	0.6%	56.8	4.7	0.2%
Industrial	357.2	19.9	0.9%	12.2	0.7	0.4%
Irrigation	---	---	---	---	---	---
Total	**507.2**	**37.5**	**0.5%**	**69.0**	**5.4**	**0.1%**

Figure 16 shows that the majority of potential is from Utah; Wyoming has a significant quantity of industrial load potential, including chemical manufacturing, mining, and "miscellaneous" manufacturing.

Figure 16. Curtailable Tariff Program: Market Potential by State (MW in 2027)

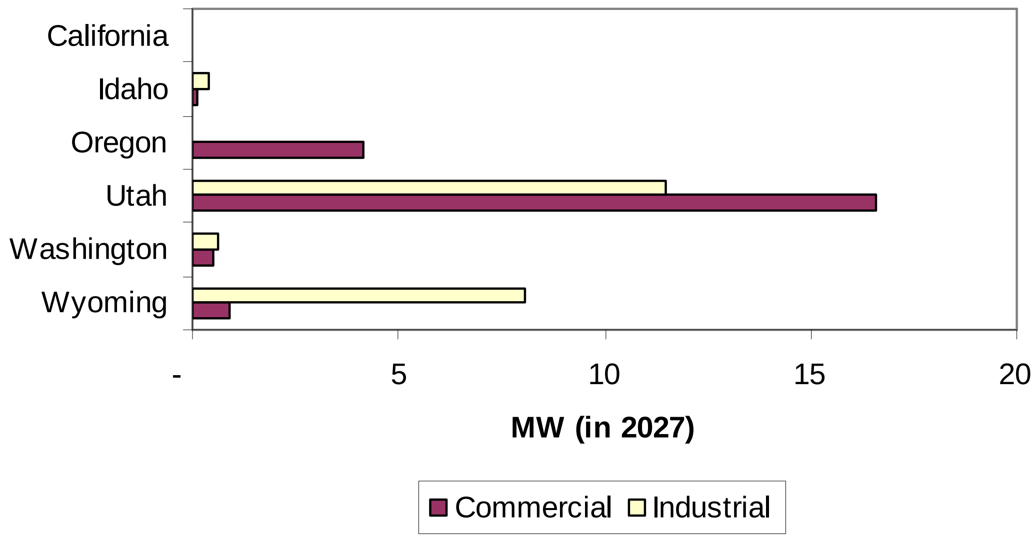

Table 22 shows the levelized costs and MW of potential for base and high achievable scenarios. Under the expected achievable scenario, the curtailable tariff program costs $59/kW-year for the Rocky Mountain Power service territory, which passes all economic screens under expected achievable assumptions. For Pacific Power, the costs are $61/kW-year; therefore more expensive than the threshold in nearly all cases. These costs are estimated using an assumption of $400,000 of program development costs, $1,400 for hardware costs (communications, connectivity, and meters, if necessary), and $500 in marketing for each new participant. New participant costs would be required for customers that drop out of the program, assumed to be 5% based on electrical turnover rates. Additionally, it is assumed the hardware has a 20-year life. Incentives are assumed to be $48/kW-year, which is $4/kW-month, a figure consistent with payments by PG&E, SCE, MidAmerican Energy Company, Duke, and Alliant. For an analysis of expected costs of standby generation, see Chapter 5, Supplemental Resources.

To account for uncertainty in program participation rates, the high achievable scenario assumes all survey customers who felt “very positive” and half of those who felt “somewhat positive” would participate. This figure is 23% overall for the curtailable program. Additionally, the high achievable scenario assumes a 50% increase of incentive payments; therefore, Table 22 shows the potential increases in the Rocky Mountain Power territory to 65 MW for costs of $85/kW-year and 9 MW with a cost of $88/k-year in the Pacific Power territory.

Table 22. Curtailable Tariff Program: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	38	$59	Pass	Pass	Pass
High Achievable	65	$85	---	Pass	Pass
Pacific Power					
Expected Achievable	5	$61	---	---	Pass
High Achievable	9	$88	---	---	---

Demand Buyback

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

DBB is a mechanism enabling consumers to actively participate in electricity trading by offering to undertake changes in their normal consumption patterns. Participation requires the flexibility to make changes to their normal electricity demand profile, install the necessary control and monitoring technology to execute the bids, and demonstrate bid delivery. One of several Internet-based programs is generally used to disseminate information on buyback rates to potential customers, who can then take the appropriate actions to manage their peak loads during requested events. The program option in this analysis targets the largest C&I customers (>250kW), consistent with national programs.

Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for energy reduced during each event, based primarily on the difference between market prices and utility rates. All major investor-owned utilities in the Northwest and Bonneville Power Administration have offered variants of this option, beginning in 2001. PacifiCorp's current program, Energy Exchange, was used extensively during 2001 and resulted in a maximum reduction of slightly over 40 MW during that period. Demand reductions from PacifiCorp's current Energy Exchange program averaged 4 MW in 2006 with a maximum of 17 MW on July 27, 2006. DBB products are common in the United States and are being offered by many major utilities. The use of DBB offerings as a means of mitigating price volatility in power markets is especially common among independent system operators, including CAISO, NYISO, PJM, and ISO-NE. However, DBB options are not currently being exercised regularly due to relatively low power prices. The IEA survey of 40 utilities' capacity-focused programs revealed about half of the utilities surveyed were offering DBB programs to their C&I customers. Investor-owned utilities offering programs include almost all of the major utilities in California, Illinois, Indiana, Iowa, Minnesota, and Wisconsin as well as a variety of other utilities, including Allegheny Energy, KCP&L, and Portland General Electric.

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

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

To estimate potential, detailed C&I audits from California are used to determine the technically available portion of the load basis. Program participation, varying by sector, is based on the results of the customer survey, adjusted to account for the quantity of load currently under contract with Energy Exchange,[33] with an overall customer response of 20%. Zero market potential is estimated for health, lodging, and petroleum manufacturing based on survey responses. Although there were few comments about DBB, several customers noted the "lack of value" they perceived from this program.

One of the most important and difficult factors to estimate for DBB is the quantity of load curtailment that can be expected during any individual event. Quantec thoroughly analyzed past records of PacifiCorp's Energy Exchange program results from 2000 to 2006 to estimate the elasticity or quantity of load bid into the market given posted market prices. The data did not provide logical or statistically significant results as business conditions and customers' willingness are major drivers of participation.

Therefore, event participation is assumed to be twice the 2006 Energy Exchange event participation of 18% (representing the portion of participating load curtailed for the average event), assuming that increased focus on programs could improve event participation.

Table 23 shows that in the Rocky Mountain Power territory, of more than 450 MW of technical potential, an average of 27 MW can be expected during any one event, although it is expected an individual event may produce more load reduction. In the Pacific Power territory, 167 MW of technical potential results in an average of 10 MW expected during any one event. In 2006, PacifiCorp received an average of 4 MW from its Energy Exchange program, which is included in the potential below.

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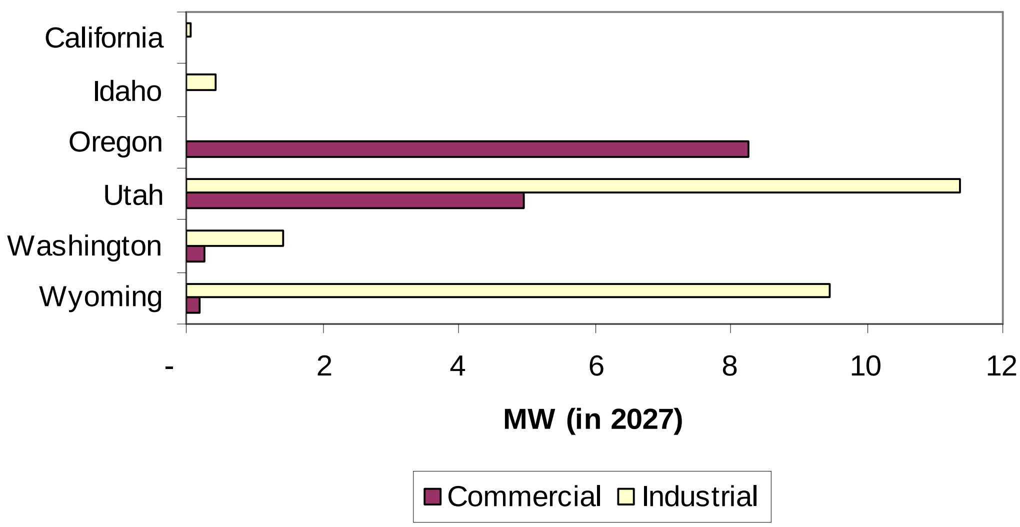
[33] Actual survey results showed an overall participation of 8%. Given that customers currently on Energy Exchange have a total demand of 420 MW, these survey results understate current participation. Therefore, survey results were increased by a factor of 2.5, resulting in 680 MW of total demand by customers to account for the potential to increase the number of customers under contract with this program.

Table 23. Demand Buyback: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	---	---	---	---	---	---
Commercial	145.2	5.2	0.2%	145.8	8.6	0.4%
Industrial	318.3	21.3	0.9%	21.4	1.5	0.7%
Irrigation	---	---	---	---	---	---
Total	**463.5**	**26.5**	**0.3%**	**167.2**	**10.1**	**0.2%**

Due to large industrial loads, Wyoming and Utah have significant potential for this program, where potential is driven by chemical manufacturing, mining, and other non-classified manufacturing.

Figure 17. Demand Buyback: Market Potential by State (MW in 2027)



Because participants are paid based on market energy rates, the cost of this program is relatively low and passes all economic screens. Table 24 shows the resulting \$18/kW-year in both the Rocky Mountain Power and the Pacific Power territory. New customer costs include hardware (\$1,400 for communications, connectivity, and any necessary metering) and marketing (\$500) and program development (\$400,000). New participant costs must be reinvested due to 5% annual attrition rates (based on electrical service only) and hardware life of 20 years. Incentives are converted from the cost per MWh to cost per kW based on historic Energy Exchange costs from 2000 to 2006, resulting in \$10 per kW[34], with an average of \$100/MWh in energy payments.

[34] Based on data that became available after the completion of the study, the 2006 Energy Exchange program's average per unit cost was \$18/kW and \$160/MWh. Therefore, the resulting levelized calculated cost of this program option may be understated.

Table 24 also shows the high achievable scenario, assuming all respondents indicating a "very positive" reaction to the program and one-half of those indicating "somewhat positive" can be convinced to participate, resulting in 29% of customers, or 38 MW for Rocky Mountain Power and 15 MW for the Pacific Power territory. Consistent with all other programs, the high achievable scenario is assumed to have a 50% increase in incentives; so costs rise to $24/kW-year, which again pass all economic screens.

Table 24. Demand Buyback: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	26	$18	Pass	Pass	Pass
High Achievable	38	$24	Pass	Pass	Pass
Pacific Power					
Expected Achievable	10	$18	Pass	Pass	Pass
High Achievable	15	$24	Pass	Pass	Pass

Residential Time of Use Rates

Information on TOU rates was obtained from tariffs from 60 U.S. utilities, promotional materials used by utilities offering new TOU (or TOU with CPP) programs during the past five years, and several interviews with utility staff members.[35] TOU rates have been offered by U.S. utilities since at least the 1970s, but the historic impacts have been quite low. In fact, PacifiCorp ran a TOU pilot in 2002 to 2004, which had extremely low program sign-up (940 residential customers at the end of 2004, with an average of 25% annual attrition), despite an intensive marketing effort.

The TOU rates developed in recent years typically differ from those of the past in several important ways. First, most new TOU rates contain three price tiers as opposed to the two-tier rates common in many long-standing TOU programs, including those offered by PacifiCorp**.** This allows utilities to set high prices during their highest peak periods and offer exceptionally low off-peak prices overnight when the cost is at its lowest and supply is plentiful. The majority of hours are assigned a "mid-peak" price that is typically a slightly discounted version of the standard rate. Another change is that the duration of the peak period is typically shorter than in the past. Finally, the price differentials between peak and off-peak prices tend to be greater than in the past to encourage load shifting away from the peak period. For long-standing TOU rates, this differential averaged about 7.6 cents/kWh, whereas newer programs tend to have a differential of greater than 10 cents/kWh. For comparison, PacifiCorp's existing TOU rates offer a price differential of roughly 4.5 cents/kWh to 7.5 cents/kWh, depending on the operating utility and the season.

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35 Includes: Gulf Power, Alabama Power, Ameren, Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, and Teco Energy. Interviews with utility staff: Arizona Public Service, Salt River Project, and Florida Power and Light.

TOU rates are assumed to be available only to the residential customer segments, and the potential is based on the total load rather than individual end uses. The technically feasible portion of the load basis expected to be reduced during peak hours is 5% based on results from California[36] and Puget Sound Energy. The participation rate of the top ten highest-enrolled TOU programs in the country[37] is on average 16%, yet these programs do not represent the experience of all national programs, many of which have participation rates of <1%. If a robust marketing effort is made in conjunction with a TOU rate design that is more than double PacifiCorp's current TOU differential, the expected participation rate is assumed to be 10%.

Table 25 shows there is 107 MW of technical potential and 11 MW of market potential in the Rocky Mountain Power territory. In the Pacific Power territory, there is 78 MW of technical potential and 8 MW of market, both representing less than 1% of 2027 territory peak.

Table 25. Time of Use Rates: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	106.7	10.7	0.5%	77.6	7.8	0.4%
Commercial	---	---	---	---	---	---
Industrial	---	---	---	---	---	---
Irrigation	---	---	---	---	---	---
Total	**106.7**	**10.7**	**0.1%**	**77.6**	**7.8**	**0.2%**

Figure 18 shows Utah has the most potential, with 9 MW, followed by Oregon with nearly 6 MW.

Table 26 displays the per-unit costs, using the assumptions of $400,000 in program development (based on 2002 PGE and PacifiCorp TOU rate program development costs[38]), $125 in new participant costs ($100 per meter and $25 of marketing), with new participant costs reoccurring with annual attrition of 5% (based on electrical turnovers[39]) and a 20-year measure life on meters. Due to low per-customer impacts, the cost per kW-year is $166/kW-year for Rocky Mountain Power territory and $173/kW-year for Pacific Power territory, which pass the economic screens. This finding is consistent with the 2005 evaluation of PacifiCorp's TOU

36 Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot, Final Report," March 16, 2005. See also, Piette, Mary Ann and David S. Watson "Participation through Automation: Fully Automated Critical Peak Pricing in Commercial Buildings," 2006, Lawrence Berkeley National Laboratory. Linkugel, Eric Proceedings of the 2006 ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, CA, August 2006.

37 FERC, 2006 and R. Gunn, "North American Demand Response Survey Results" (Association of Energy Services Professionals, Phoenix, AZ, February 2006).

38 Levelized per unit costs are driven primarily by hardware costs. Removal of upfront development reduces the results by $4/kW-year.

39 This is likely a conservative estimate - PacifiCorp 2004 pilot TOU program experienced up to 25% annual attrition.

program,[40] which was not found to be cost-effective. The high achievable scenario assumes a 16% program participation rate, based on an average of the top ten programs nationally. The per-unit levelized costs fall slightly because there is no incentive payment to increase, and the fixed (program-development) costs are spread over a higher quantity of achievable potential.

Figure 18. Time of Use Rates: Market Potential by State (MW in 2027)

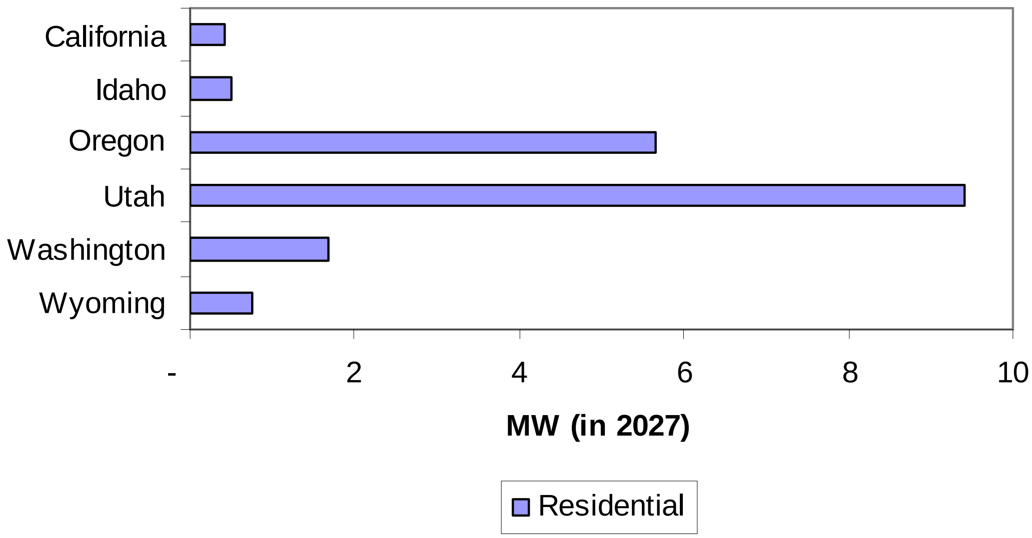

Table 26. Time of Use Rates: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	11	$166	---	---	---
High Achievable	17	$165	---	---	---
Pacific Power					
Expected Achievable	8	$173	---	---	---
High Achievable	12	$172	---	---	---

Critical Peak Pricing

Under a CPP program, customers receive a discount on their normal 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

40 Haeri, Hossein and Lauren Gage. "Analysis of the Load Impacts and Economic Benefits of the TOU Rate Option". Quantec, LLC. 2005

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 advance notice along with event criteria, such as a threshold for forecasted weather temperatures, to help customers plan their operations. One of the attractive features of the CPP program is the absence of a mandatory curtailment requirement.

The benefit of a CPP rate over a standard TOU rate is an extreme price signal can be sent to customers for a limited number of events. Utilities have found that demand reductions during these events are typically greater than during TOU peak periods for several reasons: 1) customers under CPP rates are often equipped with automated controls triggered by a signal from the utility; 2) the higher CPP rate serves as an incentive for customers to shift load away from the CPP event period: and 3) the relative rarity of CPP events may encourage short-term behavioral changes, resulting in reduced consumption during the events.

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

Currently, there are no CPP programs being offered by Northwest utilities. Peak pricing is, however, being offered through experimental pilots or full-scale programs by several organizations in the United States,[41] 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 the Western states as it has been in the East.

Residential and Small Commercial CPP. The most common national CPP programs are offered to the residential customer class. This analysis assumes that, as with DLC programs, small commercial customers (<30 kW of demand) can easily participate in a CPP program offered to residential customers. Recently, significant literature has shown the value of a technology-enabled CPP program, which essentially provides customers with smart thermostats which can be programmed to change temperature settings depending on the pricing period (e.g., critical

41 See Wolak, Frank, "Residential Customer Response to Real-Time Pricing: The Anaheim Critical-Peak Pricing" September 2006. See FERC, Assessment of Demand Response and Advanced Metering, August 2006. See Energy & Environmental Economics, A Survey of Time-of-Use (TOU) Pricing and Demand-Response (DR) Programs, July 2006. See Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot, Final Report", March 16, 2005. See also, Piette, Mary Ann and David S. Watson "Participation through Automation: Fully Automated Critical Peak Pricing in Commercial Buildings," 2006, Lawrence Berkeley National Laboratory. Linkugel, Eric Proceedings of the 2006 ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, CA, August 2006. See staff CPUC testimony at http://www.sdge.com/regulatory/tariff/A_05_03_015_%20Gaines_redline.pdf.

peak period, on-peak, or off-peak).[42] This combination of pricing and technology has shown to be an effective combination to improve per-customer load impacts. Technically, national studies have shown that 13%-40%[43] of peak demand can be reduced for participating customers; this study assumes a 27% result for the California pricing pilot.[44] In terms of program participation, this analysis assumes a base case of 5% and a high achievable participation rate of 10%. Gulf Power's CPP program currently has 2.5% of customers and a goal of reaching 10% penetration. Event participation is estimated to be 95%, based on opt-outs being typically less than 5% now that utilities require customers to use the Internet or the call center to opt out of a CPP event.

Table 27 shows that technically, 640 MW and 460 MW are available for the Rocky Mountain Power and Pacific Power territories, respectively. These figures are reduced by the program and event participation rates discussed above, resulting in 30 MW (Rocky Mountain Power) and 22 MW (Pacific Power).

Table 27. CPP Residential/Small Commercial: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	584.5	27.8	1.4%	420.6	20.0	1.0%
Commercial	54.6	2.6	0.1%	39.6	1.9	0.1%
Industrial	---	---	---	---	---	---
Irrigation	---	---	---	---	---	---
Total	**639.1**	**30.4**	**0.4%**	**460.1**	**21.9**	**0.5%**

Utah, with the largest share of residential customers, has the most overall market potential, followed by Oregon, then Washington.

42 Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, Severin Borenstein, Michael Jaske, and Arthur Rosenfeld, October 2002, FERC. DOE

43 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 email 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 (IEA), 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.

44 See Charles River Associates, 2005.

Figure 19. CPP Residential/Small Commercial: Market Potential by State (MW in 2027)

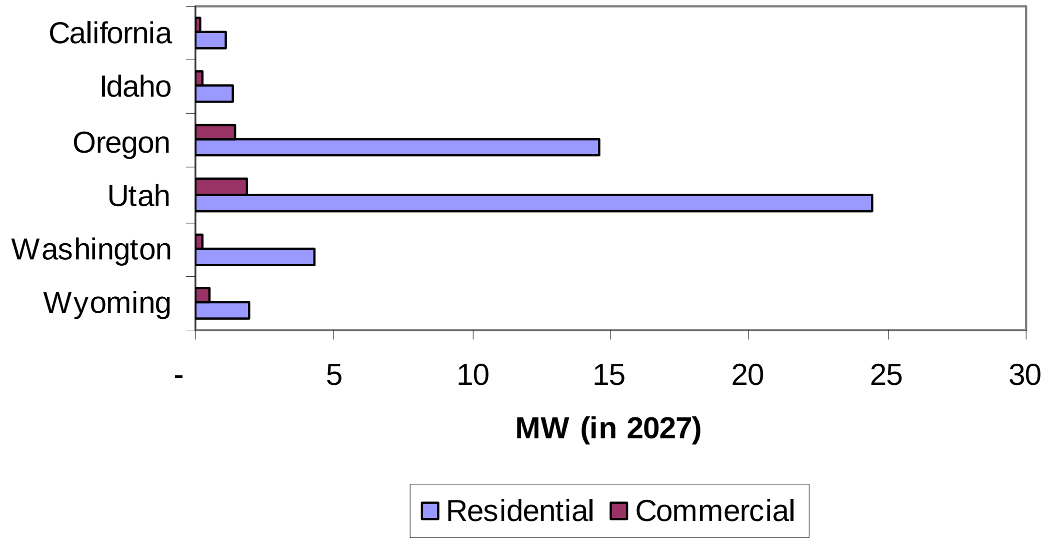

Table 28 displays the base and achievable potential results in MW and their respective costs. The levelized costs of the expected achievable scenario are expected to be $88 in the Rocky Mountain Power territory and $91 in the Pacific Power territory. The costs include $350 in new participant expenditures ($300 for a smart thermostat, meter, and installation; $50 in marketing), and $600,000 in program development costs, which are increased from TOU because both a rate structure and a technology program must be deployed. A 20-year life is assumed for the technologies, as is a 5% an annual attrition rate (requiring reinvestment of new participant costs).

The high achievable results show an increase in potential to 61 MW (Rocky Mountain Power territory) and 44 MW (Pacific Power territory), with no change in cost due to the lack of incentives for this pricing program. In the Rocky Mountain Power territory, both the base and high achievable scenarios pass the base and high economic screen. However, under both scenarios, the pricing program fails the screens in the Pacific Power territory.

Table 28. CPP Residential/Small Commercial: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	30	$88	---	Pass	Pass
High Achievable	61	$88	---	Pass	Pass
Pacific Power					
Expected Achievable	22	$91	---	---	---
High Achievable	44	$90	---	---	---

Commercial and Industrial CPP. There have been very few C&I CPP programs for medium-to-large customers, and the pilots tested in California have typically linked the CPP rate with "automated demand response" technologies that provide most of the impact. This implies the CPP rate itself and the price incentive it creates may not be the driver of load reductions.

In FERC's 2006 survey of utilities offering demand response programs, roughly 25 entities reported offering at least one CPP tariff. However, many of the tariffs were pilot programs only, and almost all of the 11,000 participants were residential customers. The top five utilities (by number of participants enrolled) accounted for 96% of the total number of participants reported to be on CPP rates. Gulf Power had the largest (about 8,000 participants), which were entirely residential. Cass Country Electric Cooperative came in next at nearly 3,000 residential-only participants. The other three in the "top five" were the three major California investor-owned utilities. Of those, only SCE included commercial customers in its pilot, and it had 270 commercial participants. The lack of commercial CPP programs is supported by a 2006 survey of pricing and DR programs commissioned by the U.S. Environmental Protection Agency, which found only four large-customer CPP programs, all of them in California.[45]

Yet in the survey of PacifiCorp customers asked about CPP rates, a significant number showed interest. Therefore, this analysis estimates potential and costs for a C&I CPP program, requiring a total load of greater than 30 kW. Technically feasible potential is based on engineering audit assumptions, which are consistent with CPP studies showing an average of 8% savings.[46] Event participation of 56% is based on the 2006 California C&I Pilot,[47] and accounts for the higher rate of opt-outs expected for commercial customers. As stated earlier, the survey of PacifiCorp customers revealed that, given multiple program options (with the option of participating in no program), 24% of respondents stated they would choose the CPP option (over DBB, curtailment, RTP, and TOU rates). Upon further analysis, however, the research team is concerned this response was biased by the description: "A voluntary pricing program that offers lower overall prices year-round, but charges higher prices for electricity used during designated 'critical peak periods.'"[48] Therefore, a 50% reduction is made, resulting in 12% of customers participating.

Table 29 shows there is 665 MW of technical potential in the Rocky Mountain Power territory, with 61 MW market potential (representing nearly 1% of 2027 territory peak). The Pacific Power territory has 164 MW of technical potential and 9 MW of market potential. The majority of market potential is in the industrial sector, dominated by Utah and Wyoming loads.[49]

45 See "Participation through Automation: Fully Automated Critical Peak Pricing in Commercial Buildings," Mary Ann Piette, David S. Watson, Naoya Motegi, Sila Kiliccote, Lawrence Berkeleyational Laboratory, Eric Linkugel, Pacific Gas and Electric Company, Proceedings of the 2006 ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, CA, August 13-18, 2006. See also, Charles River Associates, Impact Evaluation of the California Statewide Pricing Pilot, Final Report, March 16, 2005.

46 LBNL Fully Automated CPP study, 2006.

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

48 At issue is that respondents may think that their annual bill will be significantly lower by participating, although CPP programs are typically designed to be revenue neutral for the utility.

49 Petroleum manufacturing is assumed to have zero achievable potential, per survey results

Table 29. CPP C&I: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	---	---	---	---	---	---
Commercial	320.9	18.0	0.6%	139.3	5.9	0.2%
Industrial	344.3	43.1	1.9%	24.9	3.4	1.6%
Irrigation	---	---	---	---	---	---
Total	**665.2**	**61.2**	**0.8%**	**164.2**	**9.3**	**0.2%**

Figure 20. CPP-C&I: Market Potential by State (MW in 2027)

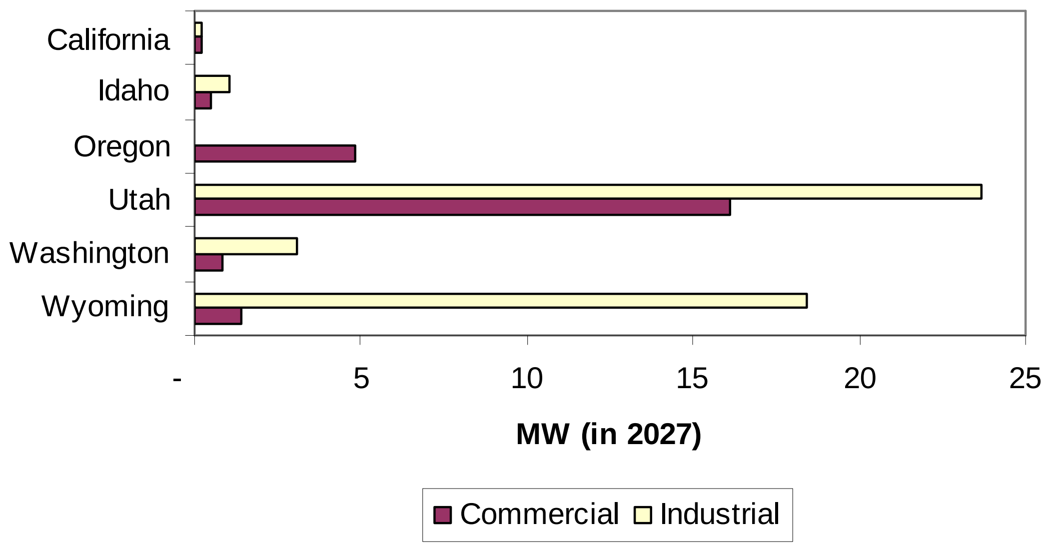

Table 30 displays the MW of market potential and levelized costs for the base and high scenarios. The expected achievable scenario passes all economic screens, at a cost of $12 in the Rocky Mountain Power, increasing to $33 in the Pacific Power territory due to smaller average loads. The costs included in these estimates are $1,900 in new participant costs ($1,400 hardware and $500 marketing), with $400,000 in program development costs. A 20-year life is assumed for the technologies, and a 5% annual attrition rate is assumed (requiring reinvestment of new participant costs).

The high achievable scenario assumes, using the survey results, all of those who felt “very positive” about the program and one-half of those who felt “somewhat positive” would participate. These results are also scaled by 50%, resulting in 89 MW of achievable potential in the Rocky Mountain Power territory and 14 MW in the Pacific Power territory. The costs are essentially unchanged because there is no incentive in this program; therefore, all economic screens are passed.

Table 30. CPP C&I: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	61	$12	Pass	Pass	Pass
High Achievable	89	$12	Pass	Pass	Pass
Pacific Power					
Expected Achievable	9	$33	Pass	Pass	Pass
High Achievable	14	$33	Pass	Pass	Pass

Real-Time Pricing

Commercial and Industrial RTP

Under RTP programs, electricity prices vary each hour according to the expected marginal cost of supply and are typically established one day ahead of the time the prices are in effect. Where CPP utilizes pre-set pricing, RTP utilizes electricity wholesale prices, which change throughout the day. Programs vary from day-ahead to hour-ahead notification. Notification occurs via the Internet or technology-enabled devices (Internet- or radio-based devices).

At least 24 utilities offer RTP programs for commercial customers, although 13 are pilot programs. In states where the wholesale market is run by an Independent System Operator (e.g., MISO, PJM, ISO-NE, NYISO), prices typically reflect the hourly spot market price, either on a day-ahead or closer to a true real-time basis. For vertically integrated utilities such as Georgia Power, which has an RTP rate program, prices are set by the marginal cost of generation.

The most commonly cited reason for introducing RTP is to build customer satisfaction and loyalty by providing an opportunity for customers to realize bill savings. A two-part rate, where a Customer Baseline Load (CBL) is established and compared to actual loads, is used by Niagara Mohawk and Georgica Power, and was common in early program designs. Only the difference in actual versus expected usage is subject to real-time prices. Many newer programs have unbundled the electricity commodity from transmission and distribution services, and electricity component is priced according to hourly energy prices. Additionally, Georgia Power offers Price Protection Products that enable RTP customers to manage their exposure to volatile prices.

One important thing to note in C&I RTP programs is, while a few programs have been very successful, it can be difficult to attract participants. In the survey conducted by Lawrence Berkeley National Laboratory 50 of 42 voluntary C&I RTP programs found just three programs had more than 100 customers enrolled in 2003, which accounted for the majority of all non-residential RTP participants identified in the survey. For example, half of the programs in the study had fewer than ten customers enrolled, and one-third had no participants.

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[50] Barbose, Galen et al., A Survey of Utility Experience with Real Time Pricing, LBNL, December 2004. See also Neenan Associates, "Customer Adaptation to RTP as Standard Offer Electric Service: A Case Study of Niagara Mohawk's Large Customer RTP Tariff," LBNL 2004.

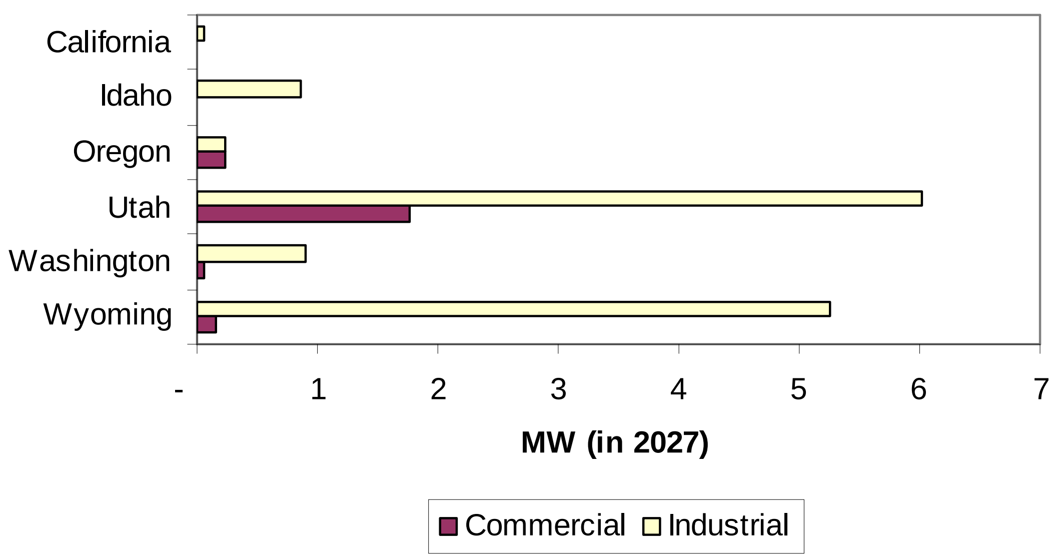
The program modeled in this analysis requires a minimum threshold of 250 kW, which is consistent with other programs nationally. Again, the technically feasible potential is based on engineering audit assumptions. Program participation is based on the survey of PacifiCorp customers, 2% of which were interested in an RTP program, which is consistent with the findings above. Comments regarding RTP were focused on the lack of predictability of energy costs, often mentioned by schools. Consistent with other studies, this finding underscores the primary barrier of RTP: customers do not want to assume the market risk of energy prices.

Table 31 shows there is 440 MW of technical potential for the Rocky Mountain Power territory, with 14 MW of market potential. The Pacific Power territory has nearly 80 MW of technical and 1.5 MW of market potential. The majority of market potential is in the industrial sector, dominated by Utah and Wyoming loads, as shown in Figure 21.

Table 31. Real-Time Pricing: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	---	---	---	---	---	---
Commercial	129.8	1.9	0.1%	48.1	0.3	0.0%
Industrial	309.7	12.1	0.5%	30.1	1.2	0.6%
Irrigation	---	---	---	---	---	---
Total	**439.5**	**14.1**	**0.2%**	**78.2**	**1.5**	**0.0%**

Figure 21. Real-Time Pricing: Market Potential by State (MW in 2027)



RTP is the lowest-cost resource due to the high expected impacts and relatively low costs for the required technologies (Table 32). The expected achievable scenario costs $6/kW-year for Rocky Mountain Power and $8/kW-year in for Pacific Power. The high achievable scenario costs less because there are no incentives in this program option. The cost components include $1,900 for each new participant ($1,400 hardware and $500 marketing) and $400,000 in program development costs. A 20-year life is assumed for the technologies and a 5% annual attrition rate (requiring reinvestment of new participant costs) is assumed

Using the survey results, the high achievable scenario assumes all of those who felt "very positive" about the program and one-half of those who felt "somewhat positive" would participate, representing 7% of surveyed customers and resulting in 49 MW of potential in the Rocky Mountain Power territory and 5 MW in the Pacific Power territory.

Table 32. Real-Time Pricing: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	14	$6	Pass	Pass	Pass
High Achievable	49	$3	Pass	Pass	Pass
Pacific Power					
Expected Achievable	1	$8	Pass	Pass	Pass
High Achievable	5	$5	Pass	Pass	Pass

Residential Real-Time Pricing

At this point, residential RTP is not widespread, but interest is reported to be increasing.[51] In Illinois in 2006, after a four-year pilot program run by the Community Energy Cooperative in Chicago with ComEd customers, the General Assembly unanimously passed legislation requiring large investor-owned utilities to offer residential RTP to all customers. New programs offered by ComEd and Ameren are launching in Spring 2007. In this study, however, the program history was judged to be inadequate to provide a reliable basis for effectively modeling this program option.

51 Anthony Star presentation, "Why Residential Real-Time Pricing is the Real Deal!" presented at Innovations in Retail Pricing, Association of Energy Services Professionals, May 18, 2006.

3. Energy-Efficiency Resources (Class 2 DSM)

Scope of Analysis

The main focus in assessing of energy efficiency (Class 2 DSM) resources was to produce reasonable estimates of savings available in PacifiCorp's service territory (Rocky Mountain Power and Pacific Power, excluding Oregon) over a 20-year planning horizon (2008 to 2027). Separate assessments of technical, economic, and achievable potential for residential, commercial, industrial, and irrigation sectors were made for California, Idaho, Utah, Washington, and Wyoming.[52] Within each state's sector-level assessment, the study further distinguished among customer segments or facility types and their respective applicable end uses. Six residential segments (existing and new construction for single-family, multifamily, and manufactured homes), 24 commercial segments (12 building types within the existing and new construction), 28 industrial segments (14 facility types, also within existing and new construction vintages), and two irrigation segments (existing and new sites) were analyzed.

The study includes a comprehensive set of energy-efficiency measures. For the commercial and residential sectors, these measures fall into two groups. The first group represents measures commonly available, based on well-understood, commercially-available technologies, and screened for state-specific applicability to the customer segments or facility types and end uses. The second group consists of emerging technology measures expected to become commercially available by 2027. For the industrial and irrigation sectors, the measures assessed consist solely of existing technologies or process improvements. The analysis began by assessing the technical potential for 156 *unique* energy-efficiency measures (Table 33).

Table 33. Energy-Efficiency Measure Counts (Base-Case Scenario)

Sector, Potential Type	Measure Counts
Commercial	
Technical	78 unique, 8,338 permutations across segments
Economic	71 unique, 4,800 permutations across segments
Achievable	68 unique, 4,304 permutations across segments
Residential	
Technical	62 unique, 3,666 permutations across segments
Economic	50 unique, 2,000 permutations across segments
Achievable	46 unique, 1,621 permutations across segments
Industrial	
Technical, Economic and Achievable	13 unique process improvements, 472 permutations across segments
Irrigation	
Technical	3 unique measures, 14 permutations across segments
Economic and Achievable	3 unique measures, 11 permutations across segments

52 Energy efficiency in Oregon is delivered by the Energy Trust of Oregon, which completed its own assessment in 2006.

Considering all permutations of these measures across all customer sectors, customer segments, and states, customized data had to be compiled and analyzed for nearly 12,500 measures. Of the 156 unique measures, 137 meet the cost-effectiveness criteria for economic potential, and 130 measures remain in the final analysis of achievable potential after increasing measure costs by 15% to account for program administration.[53] A complete list of energy-efficiency measures analyzed is provided in Volume II, Appendix C.

The remainder of this section is divided into three parts. Resource potential for energy efficiency by state and sector are presented next, followed by a detailed description of the methodology for estimating the technical, economic, and achievable energy-efficiency potential. The section concludes with more detailed results and an assessment of the potential under alternative economic and market acceptance scenarios.

Resource Potential

Table 34 and Table 35 show 2027 baseline sales and potential by sector and state, respectively. As shown, the results of this study indicate 1,130 aMW of technically feasible electric energy-efficiency potential by 2027, the end of the 20-year planning horizon. Approximately 913 aMW of these resources are cost-effective at an average levelized per-unit cost of 4 cents/kWh. Across all sectors and states, 502 aMW (nearly 45% of the technical potential and 55% of the economic potential) are estimated to be achievable. If acquired, the identified achievable potential amount to 7% of forecast load in 2027 and 22% of the projected load growth from 2008 to 2027 in PacifiCorp's system, excluding Oregon. Across the system, the identified achievable potential represents about 25 aMW of saving per year, equating to approximately 0.35% of the system load.[54] Savings as a percentage of system load vary by sector and state as shown in Table 34 and Table 35.

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

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[53] The addition of administrative costs only during the assessment of the achievable potential is generally consistent with other potential assessments, including that of the Northwest Power and Conservation Council.

[54] Actual savings will vary by year, as a portion of the achievable potential comes from new construction, and the timing of acquisition is dictated by the sector specific anticipated growth patterns.

Table 34. Technical, Economic and Achievable Energy-Efficiency Potential (aMW in 2027) by Sector

Sector	2027 Baseline Sales	Technical Potential	Economic Potential	Achievable Potential	Achievable as % of 2027 Baseline Sales	Resource Cost Levelized $/kWh
Residential	2,043	421	350	157	8%	$0.05
Commercial	2,695	511	372	223	8%	$0.04
Industrial	2,242	178	177	114	5%	$0.01
Irrigation	132	20	14	8	6%	$0.03
Total	**7,111**	**1,130**	**913**	**502**	**7%**	**$0.04**

Note: Results may not sum to total due to rounding.

Table 35. Technical, Economic, and Achievable Energy-Efficiency Potential (aMW in 2027) by State

State	Baseline Sales	Technical Potential	Economic Potential	Achievable Potential	Achievable as % of Baseline Sales	Resource Cost Levelized $/kWh
CA	146	27	20	10	7%	$0.04
ID	368	68	57	30	8%	$0.04
UT	4,401	755	601	328	7%	$0.04
WA	667	121	94	51	8%	$0.04
WY	1,529	158	140	82	5%	$0.03
Total	**7,111**	**1,130**	**913**	**502**	**7%**	**$0.04**

Note: Results may not sum to total due to rounding

Table 36 shows the technical, economic, and achievable potential by sector and resource type, which refers to whether the resources are discretionary or represent lost opportunities. Discretionary resources are opportunities existing in current building stock (retrofit opportunities in existing construction), while lost opportunities are those reliant on equipment burnout and new construction. The largest savings share in the industrial and irrigation sectors are comprised of discretionary resources. In addition, the nature of available data makes it difficult to isolate the lost opportunity share of savings. Therefore, all savings in these sectors are classified as discretionary.[55] Overall, discretionary resources represent 75% (379 aMW) of the achievable potential, as shown in Table 36.

[55] In the residential and commercial assessments, lost opportunities are tied to specific forecasts for new construction and decay patterns for specific types of end-use equipment (chillers, water heaters, etc.). In the industrial sector, these two elements do not have sufficient market data to allow the delineation of lost opportunities, though many exist.

Table 36. Technical, Economic, and Achievable Energy-Efficiency Potential (aMW in 2027) by Sector and Resource Type

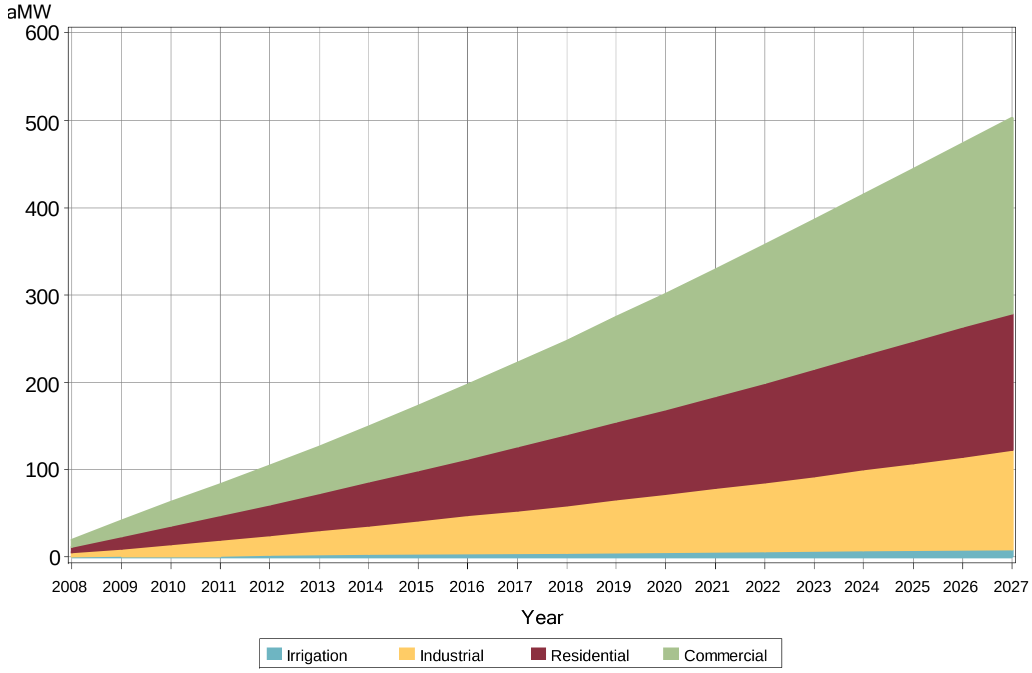
Sector	Technical Potential		Economic Potential		Achievable Potential	
	Discretionary	Lost Opportunity	Discretionary	Lost Opportunity	Discretionary	Lost Opportunity
Residential	269	152	238	112	116	41
Commercial	279	233	211	161	141	82
Industrial	178	- - -	177	- - -	114	- - -
Irrigation	20	- - -	14	- - -	8	- - -
Total	**745**	**384**	**640**	**274**	**379**	**123**

Note: Results may not sum to total due to rounding.

The distinction between discretionary and lost opportunity resources becomes important in the context of timing of resource availability and acquisition planning. Lost opportunity resources are timing-driven: when a piece of equipment fails, there is an opportunity to install a high-efficiency model in its place. If standard equipment is installed, in the absence of early replacement, the high-efficiency equipment could not be installed until the new equipment reaches the end of its normal life cycle. The same is true for new construction, where resource acquisition opportunities become available only when a home or building is built. On the other hand, discretionary resources are not subject to the same timing constraints. For this study, it is assumed both discretionary and lost opportunity resources will be acquired in equal increments over the planning horizon.[56] Figure 22 shows the realization of resources for each sector, assuming equal annual increments.

[56] Deployment of discretionary resources may be accelerated under some circumstances, provided a need exists for energy resources in the short term. An accelerated schedule, however, would likely raise the marketing and delivery expenses above the assumed 15% typical of PacifiCorp's past programs. Since total measure costs directly affect levels of economic (and achievable) potential, lower levels of economic potential should be expected if higher administrative costs are assumed.

Figure 22. Acquisition Schedule for Achievable Savings by Year and Sector



To accurately assess potential available between 2008 and 2027, this study not only evaluates well-established technology but also considers "emerging technologies" (ET) for the residential and commercial sectors that are expected to become commercially viable in the near future. In some cases, these new technologies would supplant existing technologies (e.g., LED interior lighting replacing compact fluorescent lights), while other measures represent new opportunities for energy efficiency (e.g., residential leak-proof duct fittings). The distribution of technical, economic, and achievable potential by emerging and existing technology is shown in Table 37. Emerging technologies account for roughly 5% of the achievable potential in 2027.

Table 37. Technical, Economic and Achievable Energy-Efficiency Potential (aMW in 2027) by Sector and Technology Type

Sector	Technical Potential		Economic Potential		Achievable Potential	
	Existing Technology	Emerging Technology	Existing Technology	Emerging Technology	Existing Technology	Emerging Technology
Residential	383	37	315	35	141	16
Commercial	478	33	349	23	212	11
Industrial	178	- - -	177	- - -	114	- - -
Irrigation	20	- - -	14	- - -	8	- - -
Total	**1,059**	**70**	**855**	**58**	**475**	**27**

Note: Results may not sum to total due to rounding

Resource Potential under Alternative Scenarios

To provide additional perspective on future resource potential and to account for uncertainties regarding future energy cost and market conditions, Class 2 DSM potential was estimated under alternative future scenarios concerning avoided costs and likely customer participation rates in various program offerings. The potential was examined under three economic scenarios (“base-case,” “high,” and “low”) and two achievable scenarios (“expected” and “high”). The economic scenarios were constructed based on the alternative avoided cost assumptions using IRP energy cost decrements by customer class and load shape in each territory.

Achievable scenarios are developed assuming different levels of market acceptance as a function of incentives offered to participants. The expected and high market acceptance rates correspond to utility program incentives designed to cover 50% and 75%, respectively, of the customer’s costs (per data obtained from the survey of PacifiCorp’s customers for the non-residential sectors and the survey of DSM experts for the residential sector).

Sector and state level results for these six scenarios are presented in Table 38 and Table 39, respectively. As shown, changes in avoided costs tend to have a moderate impact on energy-efficiency potential. A change in avoided cost decrement from its low to high value is expected to increase 131 aMW (30%) in resource potential under the expected achievable scenario.

Table 38. Economic and Achievable Scenarios: Achievable Potential by Sector (aMW in 2027)

Sector/Achievable Scenario	2007 Decrement	High Decrement	Low Decrement
Residential			
Expected Achievable	157	169	134
High Achievable	189	203	161
Commercial			
Expected Achievable	223	265	173
High Achievable	240	286	186
Industrial			
Expected Achievable	114	114	114
High Achievable	117	117	117
Irrigation			
Expected Achievable	8	8	12
High Achievable	9	9	13
Total			
Expected Achievable	502	560	429
High Achievable	555	619	472

Table 39. Economic and Achievable Scenarios: Achievable Potential by State (aMW in 2027)

State/Achievable Scenario	Base Decrement	High Decrement	Low Decrement
California			
Expected Achievable	10	13	9
High Achievable	12	14	10
Idaho			
Expected Achievable	30	35	26
High Achievable	34	39	30
Utah			
Expected Achievable	328	366	276
High Achievable	363	405	305
Washington			
Expected Achievable	51	59	43
High Achievable	57	66	48
Wyoming			
Expected Achievable	82	87	75
High Achievable	89	94	80
Total			
Expected Achievable	**502**	**560**	**429**
High Achievable	**555**	**619**	**472**

Alternative assumptions concerning utility program incentives change the achievable potential. Under the base-case economic scenario, increasing incentives by 50% (from 50% to 75% of costs) is forecasted to change resource potential by about 10% (from 502 aMW to 555 aMW). These results suggest participation in energy-efficiency programs appears to be relatively inelastic with respect to incentive levels above the 50% assumed in the expected achievable scenario. Moreover, although higher incentives do not affect total resource costs, they do increase costs the utility bears.

Assessment Methodology

Overview

Determination of energy-efficiency potential is based on a sequential analysis of various energy-efficiency measures in terms of technical feasibility (technical potential), economic viability based on standard cost-effectiveness criteria (economic potential), and expected market acceptance considering normal barriers that may impede implementation of the measure (achievable potential). The assessment is carried out in two main steps:

- ***Baseline forecasts:*** Determine 20-year future energy consumption by segment and end use, which is calibrated to PacifiCorp's system load forecasts in each state. The baseline forecast reflects efficiency characteristics of current codes and standards, which are assumed to be fixed (frozen efficiency) over the forecast horizon.

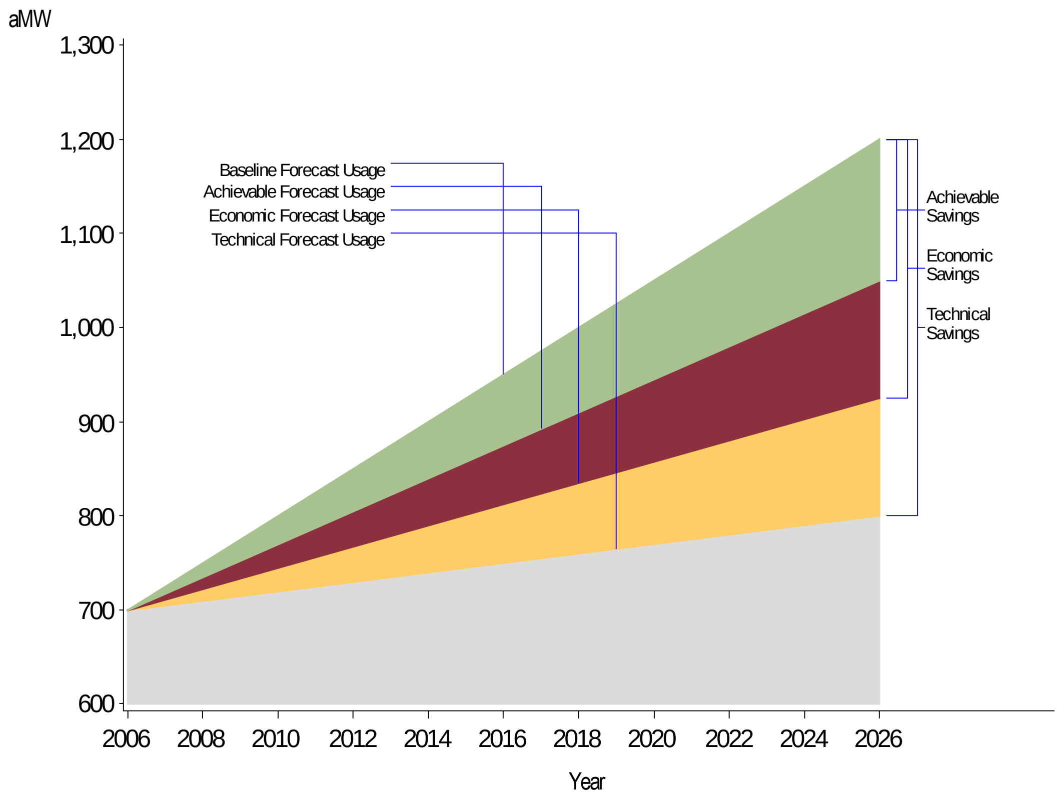
- ***Estimation of alternative forecasts of technical, economic, and achievable potential:*** Estimate technical, economic, and achievable potential based on alternative forecasts reflecting technical impacts of specific energy-efficiency measures, cost-effectiveness of the measures, and market constraints, respectively. The difference between the baseline and each alternative forecast represents the energy-efficiency potential associated with that particular type of potential.

These steps are represented conceptually in Figure 23, which shows a hypothetical baseline forecast along with the three alternative forecasts associated with technical, economic, and achievable potential.[57] These alternative forecasts represent consumption under different sets of assumptions, and the difference between the baseline and each alternative forecasts represents their respective potential savings. For example, the technical potential forecast represents total consumption after incorporation of all measures, consistent with the definition above. The results are intuitive, with total consumption in the technical potential forecast much lower than the baseline, which also indicates the greatest amount of potential. As their respective benefit-cost and market acceptance constraints are added, forecasts for economic and achievable scenarios each come closer to the baseline, and their resulting potential savings decrease.

This approach has two advantages. First, savings estimates are driven by a baseline calibrated to PacifiCorp's sales forecasts and thus consistent with IRP. The sales forecast serves as a reality check and helps control for possible errors. Other approaches may simply generate the total potential by summing the estimated impacts of individual measures, which can result in estimates of total savings that represent an unrealistically high percentage of baseline sales. Second, the approach maintains consistency among all the assumptions underlying the baseline and alternative (technical, economic, and achievable) forecasts. In the alternative forecasts, relevant inputs at the end-use level are changed to reflect the impact of energy-efficiency measures. Because the estimated savings represent the difference between the baseline and alternative forecasts, they can be directly attributed to specific changes made to analysis inputs. A transparent framework results that allows tracing linkages between various assumptions and calculated measure impacts.

57 The baseline and alternative forecasts shown in Figure 23 are purely for example and do not represent the actual data underlying this assessment.

Figure 23. Representation of Alternative Forecast Approach to Estimation of Energy-Efficiency Potential



Data Sources

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

- ***PacifiCorp***. 2006 load forecasts, economic assumptions (discount rates, conservation credits), historical energy-efficiency activities, current customer counts and forecasts, and the 2004 Energy Decisions Survey. A complete list of data elements provided by PacifiCorp is shown in Table 40.
- ***Primary Data Collection***. Two separate surveys were conducted to provide data for this study. The first surveyed more than 200 PacifiCorp customers in the C&I sectors and was used in the assessment of energy-efficiency potential, primarily to develop estimates of market acceptance. The second was a smaller survey of 30 HVAC and lighting contractors, which was used to assess variations in costs for urban and rural populations and to validate measure characterization assumptions.

Table 40. Class 2 DSM PacifiCorp Data Sources

Data Element	Key Variables	Use in This Study
2006 sales and customer counts	Number of customers and total sales by state and customer segment.	Base year customers and sales for calibration in end-use model.
2006 load forecasts by rate class	Sales and customer forecasts by state and customer segment, excluding all DSM activity.	End-use model calibration, new customers as drivers in end-use model development.
Historical program activity/achievements	Program participation and historical program achievements.	Measure saturations, validation of measure characterization (savings, costs).
2004 Residential Energy Decision Survey	Dwelling characteristics, equipment saturations, and fuel shares.	Dwelling type breakouts, square footage per dwelling, applicability factors, incomplete factors, development of building simulation prototypes, forecast calibration.
2004 Commercial Energy Decision Survey	Building characteristics, equipment saturations, and fuel shares.	Building type breakouts, square footage per dwelling, measure applicability factors, development of building simulation prototypes, forecast calibration.

- ***Building Simulations***. Estimates for normal consumption and load profiles for the majority of end uses in the residential and commercial sectors were developed specifically for this study using the eQuest (commercial) and Energy-10 (residential) building simulation models. Separate models were created for each state, customer segment, and construction vintage. Inputs and outputs for these models are presented in detail in Volume II, Appendix F.
- ***Pacific Northwest Sources***. Several Northwest entities provided data critical to this study, including the Northwest Power and Conservation Council (NWPCC), the Regional Technical Forum (RTF), and the Northwest Energy Efficiency Alliance (NEEA). This information included technical information on measure savings, costs, and lives, hourly end-use load shapes (to supplement buildings simulations described above), and commercial building and energy characteristics. Details are provided in Table 41.

Table 41. Class 2 DSM Pacific Northwest Data Sources

Pacific Northwest Data Source	Key Variables	Use in This Study
NWPCC Fifth Power Plan	Measure data, energy-efficiency potential estimates.	Measure savings, costs, and lives; cross-check of potential estimates.
NWPCC Hourly Electric Load Model (HELM)	Hourly load shapes.	Hourly end-use load shapes for residential, commercial, and industrial sectors.
RTF Web site	Measure data.	Measure savings, costs, and lives.

- ***California Energy Commission***. This study used information available through the 2005 Database of Energy Efficiency Resources (DEER) to validate many of the assumptions and data collected on energy-efficiency measure costs and savings.
- ***Equipment Vendors and Trade Allies***. Cost data for various measures were compiled from the most recent information available from regional equipment suppliers. Additional

information concerning the technical feasibility of specific measures was obtained through interviews with installation contractors throughout PacifiCorp's system.

- ***Ancillary Sources***. Other data sources consisted primarily of available information from past energy-efficiency market studies, energy-efficiency potential studies, and evaluations of energy-efficiency programs in the Northwest and elsewhere in the country. The primary information sources on the industrial section were the U.S. Department of Energy, Energy Information Administration Office of Industrial Technologies (including the Industrial Assessment Centers database), and NEEA's Industrial Efficiency Alliance initiative. A 2006 survey of a diversified group of DSM experts was used as a source for estimating achievable potential in the residential existing and new construction segments.

Baseline Forecasts

PacifiCorp's state-level econometric forecasts form the basis for assessing energy-efficiency potential. Prior to estimating potential, state-level load forecasts are disaggregated by customer sector (residential, commercial, and industrial (including irrigation); customer segment (business, dwelling, and facility types); building vintage (existing structures and new construction); geography (rural versus urban); and end uses (all applicable end-uses in each customer sector and segment).

The first step in developing the baseline forecasts is to determine the appropriate customer segments within each state and sector. These designations were based on categories available in some of the key data sources used in this study, primarily PacifiCorp's load forecasts and the 2004 Energy Decisions Survey. Next, appropriate end uses are mapped to relevant customer segments in each state.[58] Table 42 through Table 44 show the full set of customer segments and end uses for each sector analyzed in this study. For a comprehensive list of the state- and sector-specific segments and end uses, see Volume II, Appendix B.

[58] Note all segments are not applicable to all states. For example, the "large office" segment is not relevant in the California service territory as the area is entirely rural. Similarly, not all end uses within a sector are necessarily relevant in every customer segment (e.g., cooking in the warehouse segment of the commercial sector).

Table 42. Residential Sector Dwelling Types and End Uses

Residential Customer Segments	Electric End Uses
Manufactured	Central AC
Multi-Family	Central Heat
Single-Family	Cooking Oven
	Cooking Range
	Dryer
	Evaporative AC
	Freezer
	Heat Pump
	Lighting
	Plug Load[59]
	Refrigerator
	Room AC
	Room Heat
	Water Heat

Table 43. Commercial Sector Customer Segments and End Uses

Commercial Customer Segments	Electric End Uses
Grocery	Cooking
Health	Cooling Chillers
Large Office	Cooling DX
Large Retail	Heat Pump
Lodging	HVAC Aux
Miscellaneous	Lighting
Restaurant	Plug Load[60]
School	Refrigeration
Small Office	Space Heat
Small Retail	Water Heat
Warehouse	
Controlled Atmosphere Warehouse	

59 Plug load in the residential sector includes a variety of home electronics and appliances, including office equipment and entertainment systems. Volume II, Appendix F, provides a thorough review of this end use and the different appliances and equipment associated with it.

60 Plug load in the commercial sector is primarily office equipment, but might also include non-commercial refrigeration, cooking, or other appliances.

Table 44. Industrial Sector and End Uses

Industrial Customer Segments (NAICS)	Electric End Uses
Chemical Mfg	Fans
Electronic Mfg	HVAC
Food Mfg	Lighting
Industrial Machinery	Motors Other
Lumber Wood Products	Other
Miscellaneous Mfg	Process Air Compressor
Paper Mfg	Process Cool
Petroleum Mfg	Process Heat
Primary Metal Mfg	Process Other
Stone Clay Glass Products	Process Refrigeration
Transportation Equipment Mfg	Pumps
Mining	
Irrigation	
Wastewater	
Water	

Once the appropriate customer segments and end uses have been determined for each sector, the integration of current and forecasted customer counts with key market and equipment usage data produced the baseline end-use forecasts. For commercial and residential sectors, the total baseline annual consumption for each end use in each customer segment is calculated as shown below:

$$EUSE_{ij} = \Sigma_e\, ACCTS_i * UPA_i * SAT_{ij} * FSH_{ij} * ESH_{ije} * EUI_{ije}$$

where:

$EUSE_{ij}$ = total energy consumption for end use j in customer segment i

$ACCTS_i$ = the number of accounts/customers in customer segment i

UPA_i = the units per account in customer segment i (UPA_i is generally the average square feet per customer in commercial segments and 1.0 in residential dwellings, which are assessed at the whole-home level[61])

SAT_{ij} = the share of customers in customer segment i with end use j

FSH_{ij} = the share associated with electricity in end use j in customer segment i

ESH_{ije} = the market share of efficiency level e in the equipment for customer segment ij

61 It is important to note the average square footage by home type is an input into the building simulations, so weather and size of homes differences among states are reflected in the results.

EUI_{ije} = end-use intensity, energy consumption per unit (per square foot for commercial) for the equipment configuration *ije*

Total annual consumption in each sector is then determined as the sum of EUSEij across the end uses and customer segments. The key to ensuring accuracy of the baseline forecasts is the calibration of the end-use model estimates of total consumption to actual sales from 2006. This calibration to base year sales includes making appropriate adjustments to data where necessary to conform to known information about customer counts, appliance and equipment saturations, and fuel shares from a variety of sources.

Consistent with other potential studies and commensurate with the industrial end use consumption data that vary widely in quality, the industrial sector's allocation of loads to end uses in various segments (NAICS) was based on data available from the U.S. Department of Energy's Energy Information Administration.[62] For the irrigation sector, the total load in each state is well established and consists almost entirely of pumping, so there was no allocation of load to other end uses or processes.

Summaries of the baseline forecasts for each state and sector are provided in Volume II, Appendix C.

Derivation of End-Use Consumption Estimates

Estimates of end-use energy consumption (EUI_{ije}) are one of the most important components in the development of the baseline forecast. In the residential sector, these estimates are based on the unit energy consumption (UEC), which represents the annual kWh consumption associated with the end use (in some cases, the end use represents the specific type of equipment, such as a central air conditioner or heat pump) at the building level. For the commercial sector, the consumption estimates are treated as end-use intensities (EUIs), which represent the annual kWh consumption per square foot of structure. The accuracy of these estimates is critical, so they account for weather and other factors described below that drive differences among the various states and segments. For the industrial sector, end-use energy consumption represents the total annual facility consumption by end use as allocated by the secondary data described above. In the case of irrigation energy consumption, total use and end use are the same (i.e., pumping and the forecasted sales in each state do not require further allocation).

In the residential and commercial sectors, the majority of end-use consumption estimates are derived from building simulation models (eQuest and Energy-10 for commercial and residential segments, respectively)[63] to account for key regional differences, including weather, state codes, building size, and shell characteristics. For non-weather-sensitive end uses that cannot be modeled within a building simulations framework (e.g., residential refrigerators), the consumption estimates are taken from the Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS) and the Commercial Building Energy

[62] U.S. DOE, Energy Information Administration, Manufacturing Energy Consumption Survey (2002).

[63] For details on eQuest and Energy-10, see http://www.doe2.com and http://www.sbicouncil.org/store/e10.php, respectively

Consumption Survey (CBECS). Most key drivers in developing the simulation models (operating schedules, setback temperatures, and building size) are developed from data from PacifiCorp's Energy Decisions Survey.[64] Summaries of the estimates for end-use consumption for residential (UECs), commercial (EUIs), and industrial (end-use percentages) are provided in Volume II, Appendix F.

Estimating Technical Potential

After the development of the baseline forecasts, the next step is estimation of technical potential. Because technical potential is based on creating an alternative forecast[65] that reflects the installation of all possible measures, the selection of appropriate energy-efficiency resources to include in this study is a central concern. For the residential and commercial sectors, the study began with a broad range of energy-efficiency measures for possible inclusion. These measures are screened to include only measures commonly available, based on well-understood technology, and applicable to PacifiCorp's buildings and end uses. Examples of these measures are found in California's Database of Energy Efficiency Resources (DEER)[66] or assessed by the Northwest Power and Conservation Council's Regional Technical Forum. The industrial sector measures are based on general categories of process improvements.[67]

Table 45, Table 47, and Table 49 outline the types of energy-efficiency measures assessed in the residential, commercial, and industrial sectors, respectively. Table 46 and Table 48 show types of emerging technology measures included in the residential and commercial sectors, respectively. Equipment measures are those replacing end-use equipment (e.g., high-efficiency central air conditioners), while non-equipment measures are those reducing end-use consumption without replacing end-use equipment (e.g., insulation). A complete list of all measures, with descriptions, is provided in Volume II, Appendix C.

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[64] Extensive effort was made to validate and cross-check the results from the Energy Decisions Surveys with data from other sources, including RECS, CBECS, and other available studies.

[65] The alternative forecast actually consists of four separate forecasts to allow delineation between existing and new construction and equipment and non-equipment measures. These distinctions are explained later in this section.

[66] Details on DEER are available at http://eega.cpuc.ca.gov/deer

[67] Industrial improvements are derived from a variety of practices and specific measures defined in the Department of Energy's Industrial Assessment Centers Database, http://www.iac.rutgers.edu/database/.

Table 45. Residential Energy-Efficiency Measures

End Use	Measure Types
Heating and Cooling	*Non-Equipment*: air-to-air heat exchangers; attic fan; cool roof; high-efficiency ceiling fan; ceiling, wall (above and below grade), floor and rim joist insulation; insulated exterior doors; duct sealing and insulation; equipment tune-up; VFD furnace fan motor; windows; Northwest ENERGY STAR-Manufactured and single-family homes (shell measures included only); whole house air sealing.
	Equipment: high-efficiency heat pumps; high-efficiency central AC; ENERGY STAR room AC; evaporative coolers.
Lighting	*Non-Equipment*: CFLs; CFL fixtures; CFL torchieres.
Water Heating	*Non-Equipment*: hot water pipe insulation; faucet aerators; low-flow showerheads; temperature setback; ENERGY STAR dishwashers and clothes washers; drain water heat recovery.
	Equipment: high-efficiency water heaters.
Appliances	*Non-Equipment*: removal of old (inefficient) appliances (refrigerator and freezer); ENERGY STAR DVD systems; ENERGY STAR digital set top receiver; ENERGY STAR HDTV; power strip with occupancy sensor; power supply transformer/converter.
	Equipment: ENERGY STAR freezers and refrigerators.

Table 46. Residential Emerging Technology Measures

End Use	Measure Types
Heating and Cooling	*Non-Equipment*: 'Check Me' and PTCS aerosol-based duct sealing; green roof (eco-roof); leak proof duct fittings.
	Equipment: advanced cold-climate heat pump.
Lighting	*Non-Equipment*: LED interior lighting.
Water Heating	Non-Equipment: Heat Trap.
	Equipment: Heat Pump Water Heater.
Appliances	*Non-Equipment*: 1 Watt standby power.
	Equipment: 1 kWh/day refrigerator.

Table 47. Commercial Energy-Efficiency Measures

End Use	Measure Types
HVAC	*Non-Equipment*: ceiling and floor insulation; duct sealing and insulation; programmable thermostats; windows; equipment tune-up; pipe insulation; automated ventilation control; evaporative cooling; DDC system (installation and optimization); fan and pump motors; terminal HVAC units; constant air to VAV conversion; cooling tower improvements; economizers; exhaust air to ventilation air heat recovery; retro-commissioning; chilled water/condenser water settings-optimization; chilled water piping loop w/ VSD control; cooling tower approach temperature; cooling tower (two speed and variable speed); pipe insulation for chillers; terminal HVAC units-occupancy sensor control; cool roof; natural ventilation; infiltration reduction; New Construction Integrated building design; premium efficiency HVAC motors; VAV box high-efficiency motors. *Equipment*: high-efficiency heat pumps; high-efficiency chillers and DX packages, ground source heat pump.
Lighting	*Non-Equipment*: reduce power density; continuous dimming and stepped dimming controls; occupancy sensors; refrigeration lighting and exit signs; integrated classroom lighting.
Water Heating	*Non-Equipment*: hot water pipe insulation; temperature setback; chemical dishwashing systems; demand controlled circulating systems; low-flow showerheads; low-flow spray heads; low-flow faucet aerators; commercial clothes washers and dryers; chemical dishwashers. *Equipment*: high-efficiency water heaters.
Refrigeration	*Non-Equipment*: high-efficiency compressors; demand control defrost; commissioning; strip curtains; floating condenser heads; case fans; reduced speed or cycling of evaporator fans; anti-sweat controls; high-efficiency ice maker; solid-door refrigerator/freezer; refrigeration system upgrade (controlled atmosphere warehouses only).
Other	*Non-Equipment:* Power burner fryer; convection oven optimized variable volume lab hood; high-efficiency vending machines; power supply transformer/converter; power strip with occupancy sensor.

Table 48. Commercial Emerging Technology Measures

End Use	Measure Types
HVAC	*Non-Equipment*: green roof; leak proof duct fittings.
Lighting	*Non-Equipment*: cold cathode lighting; induction lighting; low-wattage ceramic metal halide lamps; Solid State LED white lighting
Refrigeration	*Non-Equipment*: special glass doors for refrigerated reach-in cases.
Water Heat	*Equipment:* Heat pump water heater.

Table 49. Industrial Energy-Efficiency Measures

Electric Measure Types
Lighting Improvements
HVAC O&M
HVAC Improvements[68]
Pump System Improvements
Air Compressor Improvements
Air Compressor O&M
Process Heating Improvements
Other Motor System Improvements
Motor O&M
Fan System Improvements
Building Improvements
Refrigeration System Improvements
Process Cooling Improvements
Other Process Improvements/O&M

Once various measures are properly characterized in terms of savings and costs, technical potential is calculated by subtracting the alternative forecast from the baseline, which yields savings by all dimensions included in the segmentation design (vintage, segment, etc.). The procedure involves three analytic steps, as follows.

Determine Measure Impacts

The starting point in assessment of technical potential is the estimation of measure-level impacts. It begins by compiling and analyzing data on the following measure characteristics:

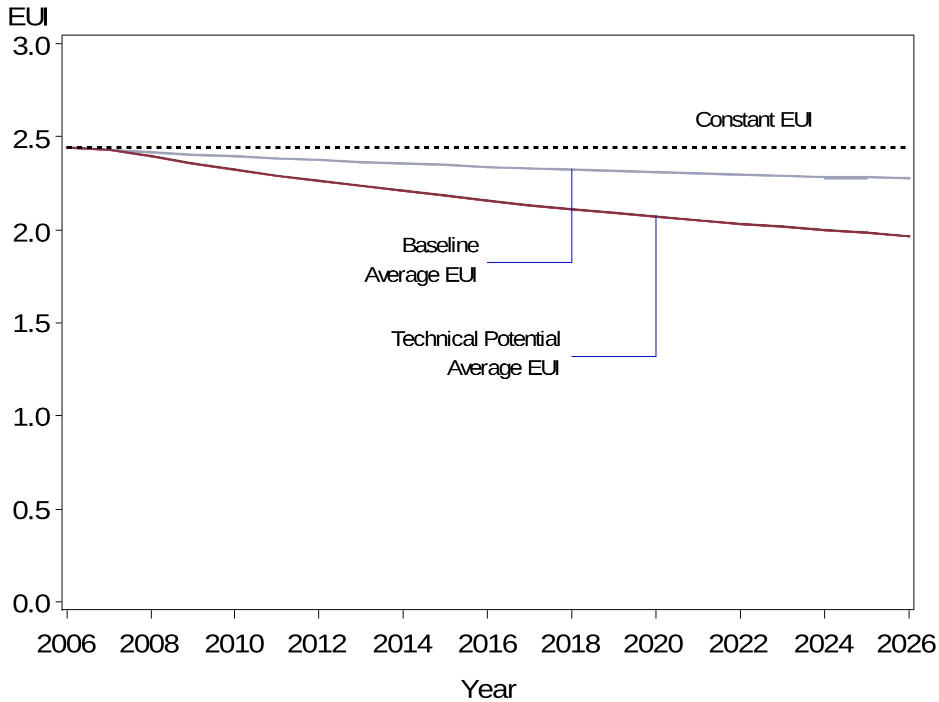
- ***Measure savings***: The energy savings associated with a measure as a percentage of the total end-use consumption. Sources include engineering calculations, energy simulation modeling, secondary data sources (case studies), and the California DEER database.
- ***Measure costs***: The per-unit cost (either full or incremental, depending on the application) associated with installation of the measure. Sources include the DEER database, RS Means, merchant websites (Home Depot, Trane, etc.), and other secondary sources.
- ***Measure life***: The expected lifetime of the measure. Sources include the DEER database, other potential studies, or DSM program evaluations.
- ***Measure applicability***: A general term encompassing a number of factors, including the technical feasibility of installation and the current or naturally occurring saturation of the measure as well as factors to allocate savings associated with competing.

In estimating potential savings of equipment measures, it is assumed the baseline efficiency for the measure would shift from its current level to prevailing codes upon burnout. Thus, it is

[68] More than one-third of the potential in HVAC is associated with clean rooms in chemical and electronics manufacturing.

assumed the average baseline efficiencies for this class of measures would improve over time as existing, sub-code equipment are replaced at the end of their normal, useful lives. An example of this methodology is provided in Figure 24, which shows the average EUI (annual kWh per square foot) associated with chillers in large offices in the baseline forecast, the technical potential scenario, and a constant EUI scenario, in which the effects of natural decay and current codes and standards are eliminated. The difference between the baseline EUI and the technical potential EUI represents the savings.

Figure 24. Example of Equipment Potential: Average EUI for Large Office Chillers in Existing Construction



The demonstration highlights two important aspects of the approach. First, the figure shows how average baseline usage gradually declines as more equipment decays and is replaced by units that comply with current code. In this case, based on an assumed 15-year life for this measure, it is expected baseline efficiency would improve to almost 14% in 2026. That is, by the end of the forecast period, all the existing sub-code equipment would be replaced by code.

Second, by contrasting the average usage in the baseline with the constant efficiency scenario, the figure shows how estimates account for effects of naturally occurring conservation. The technical potential savings are represented by the difference between the technical potential and the baseline, which would not be the case with a constant EUI. This demonstrates how this approach accurately estimates total potential and accurately accounts for naturally occurring potential. It is important to note, however, that the approach does not include any increased efficiency requirements embodied in future changes to codes and standards (that is, the baseline assumes a "frozen efficiency").

The approach for non-equipment (or “retrofit”) measures is more complicated because it requires assessing the collective impacts of a variety of measures with interactive effects. For each segment and end-use combination, the objective of the analysis is to estimate the cumulative effect of the bundle of eligible measures and incorporate those impacts into the end-use model as a percentage adjustment to the baseline end-use consumption. In other words, the objective of the approach is to estimate the percentage reduction in end-use consumption that could be saved in a “typical”[69] structure (multifamily dwelling, small office, etc.) by installing all available measures. The starting point for this approach is characterizing individual measure savings in terms of the percentage of end-use consumption rather than their absolute energy savings. For each individual non-equipment measure, savings are estimated using the following basic relationship:

$$SAVE_{ijm} = EUI_{ije} * PCTSAV_{ijem} * APP_{ijem}$$

where:

$SAVE_{ijm}$ = annual energy savings for measure *m* for end use *j* in customer segment *i*

EUI_{ije} = calibrated annual end-use energy consumption for the equipment *e* for end use *j* and customer segment *i*

$PCTSAV_{ijem}$ = the percentage savings of measure *m* relative to the base usage for the equipment configuration *ije*, taking into account interactions among measures such as lighting and HVAC calibrated to annual end-use energy consumption

APP_{ijem} = measure applicability, a fraction that represents a combination of the technical feasibility, existing measure saturation, end-use interaction, and any adjustments to account for competing measures

As described later in this section, it is appropriate to view a measure’s savings is in terms of what it saves as a percentage of baseline end-use consumption, given its overall applicability. In the case of wall insulation that saved 10% of space heating consumption, if the overall applicability is only 50%, the final percentage of the end use saved would be 5%. This value represents the percentage of baseline consumption the measure saves in an average home.

However, as stated previously, the study deals almost exclusively with cases where multiple measures affect a single end use. To avoid overestimation of total savings, the assessment of cumulative impact accounts for the interaction among the various measures, a treatment called “measure stacking.” The primary means of accounting for stacking effects is to establish a

69 This aspect of the approach requires careful determination of what a “typical” structure represents. For example, the average structure might have only a fraction of a measure installed, so it becomes necessary to think of the average single-family home, for instance, as having only 20% of a high-efficiency window already installed. Many of the attributes of structures – size, measures installed, number of stories – have been based on data collected in the Energy Decisions Survey. Summaries of attributes associated with the prototypes used in the building simulations are presented in Volume II, Appendix F.

rolling, reduced baseline applied iteratively as measures in the stack are assessed. This is shown in the equations below, where measures 1, 2, and 3 are applied to the same end use:

$$SAVE_{ij1} = EUI_{ij\,e} * PCTSAV_{ije1} * APP_{ije1}$$

$$SAVE_{ij2} = (EUI_{ije} - SAVE_{ij1}) * PCTSAV_{ije2} * APP_{ije2}$$

$$SAVE_{ij3} = (EUI_{ije} - SAVE_{ij1} - SAVE_{ij2}) * PCTSAV_{ije3} * APP_{ije3}$$

After iterating through all of the measures in a bundle, the final percentage of end-use consumption reduced is the sum of the individual measures' stacked savings divided by the original baseline consumption.

Finally, the nature of this approach requires clarification in that there are actually two different savings types associated with a measure. The first is called as stand-alone savings (the savings the measure would provide when installed entirely on its own). The second is called stacked savings (savings attributable to a measure when assessed in conjunction with other measures and accounting for the various factors that affect applicability). The former represents savings associated with a single, actual installation; the latter is intended to represent the average savings measure would achieve when installed across all homes. A summary of the factors that affect the overall potential associated with a measure are presented in Table 50.

Estimate Phased-In Technical Potential

Savings from the technical energy-efficiency potential are estimated by incorporating measure impacts (equipment and non-equipment) into the baseline forecast in four steps to develop alternative forecasts. The steps are sequential, with each case building on the previous scenario:

1. Equipment measures in existing construction, in which all equipment is upgraded to the highest level of efficiency after decay.
2. Equipment measures in new construction, in which all new construction is upgraded to the highest level of equipment efficiency.
3. Non-equipment measures in existing construction, in which collective measure energy savings impacts are applied to end-use consumption estimates.
4. Non-equipment in new construction, in which collective measure energy savings are applied to end-use consumption estimates.

The sequence of this approach is necessary to account for the interaction between equipment and non-equipment measures. As equipment is replaced over time with the highest efficiency option, average consumption associated with an end use declines. This results in a reduction in the absolute impact associated with non-equipment measures. Accounting for this interaction results in a more accurate estimate of the potential associated with non-equipment measures.

Table 50. Measure Applicability Factors

Measure Impact	Explanation	Sources
Fuel Saturation	The percentage of customers that use a particular fuel (gas or electric) in PacifiCorp's territory for the specific end use (e.g., water heat, space heat, etc.) by state.	PacifiCorp's energy decision survey – residential and commercial.
End-Use Saturation	The percentage of customers that have the specific end use. (If not all residential customers have a central AC unit, for example, the end-use saturation would be less than 100%.)	PacifiCorp's energy decision survey – residential and commercial.
Measure Share	Used to distribute the percentage of market shares for competing measures (e.g., CFLs and LEDs each have their own measure share of the market share).	Survey of installation contractors. PacifiCorp's residential and commercial surveys, various secondary sources.
Measure Incomplete Factor	Represents the percentage of buildings that do not have the specific measure currently installed.	▪ ENERGY STAR Sales Records (2003, 2004, 2005 and partial 2006). ▪ PacifiCorp's energy decision survey – residential and commercial. ▪ PacifiCorp's program database – residential and commercial.
Technical Feasibility	Accounts for the percentage of buildings that can have the measure physically installed. A couple of factors may affect this percentage, including whether the building already has the baseline measure (e.g., dishwasher) as well as limitations on installation (e.g., size of unit and space available to install the unit).	Survey of installation contractors and trade allies.
Measure Interaction	Only considered for lighting and HVAC.	Energy Simulation Modeling Engineering Judgment.
Year Introduced	Shows the year an ET measure is expected to be commercially available (varies from 5, to 10, to 15 years).	ACEEE 2004 Engineering Judgment.
Initial Share	Shows the initial impact of the measure in a percentage of the market acceptance of the emerging technology measure. All ET measures are assumed to have a 1% share in the year introduced. If the ET measure has a competing measure, that competing measure's share will be reduced to 99% (100% minus the initial share of the ET measure).	ACEEE 2004 Engineering Judgment.
Year of Final Share	Always year 20. The relationship between the initial year introduced and year 20 is assumed to be a linearly increasing function for ET measures.	ACEEE 2004 Engineering Judgment.
Final Share	This factor takes into account increasing market acceptance for the ET measure.	ACEEE 2004 Engineering Judgment.

Notes: ACEEE 2004: Emerging Energy-Savings Technologies and Practices for the Buildings Sector as of 2004 (Report A042).

Economic Potential

The approach applied in estimating economic potential is identical to the technical approach, except the impacts for both equipment and non-equipment measures are based only on measures calculated to be cost-effective using the TRC test criterion.[70] For each measure, the test is structured as the ratio of the net present values of the measure's benefits and costs. Only measures with a benefit-to-cost ratio of equal or greater than 1.0 are cost-effective and retained. That is, for each measure, we have:

$$\frac{TRCBenefits}{TRCCosts} \geq 1$$

where:

$$TRCBenefits = NPV\left(\sum_{year=1}^{measurelife}\left(\sum_{i}^{i=8760}(impact_i \times avoided\ cost_i)\right)\right)$$

and

$$TRCCosts = MeasureCost$$

Resource Benefit Components. Benefits used in the TRC calculation include the value of time- and seasonally-differentiated energy and the conservation credit developed and used by the Northwest Power Act (for Washington, Idaho, and California). To capture the full value of time- and seasonally-differentiated impacts of each measure, 2007 IRP decrement values by service territory, sector, and end use were used. Resource values vary depending on the load shape and system location. For example, resources that deliver a savings approximating a cooling load shape in the Rocky Mountain Power territory have a higher value than a flatter system load shape.

The decrement values include the 2007 IRP planning estimates for costs of externalities. These externalities, as described in the 2007 IRP, include costs associated with pollutant emissions (SO_2, NO_X, CO_2, and mercury). These costs are determined in the 2007 IRP by modeling the prices of emissions allowances under existing or projected cap and trade programs.[71] In effect, this approach produces a unique hourly (8,760) avoided cost benefit for each measure. The measure costs include the total installed cost of the measure and applicable operation and maintenance costs (or savings) associated with ensuring the measure's proper functioning over its expected life. The present value of total measure benefits are calculated by discounting future streams at PacifiCorp's weighted average cost of capital. The basis and assumptions underlying the calculation of resource benefits and costs are summarized below, with the specific assumptions used provided in Table 51.

70 Comprehensive treatments of the total resource cost test and other economic screening practices are provided in the California Standard Practice Manual, available at: http://www.energy.ca.gov/greenbuilding/documents.

71 The emissions modeling used in developing the decrement values was based on general system operations and was not based on the specific modeling of DSM impacts.

- ***Avoided hourly generation (energy) costs*.** Measures were assessed based on 2007 IRP end-use decrement values, which were grossed by 15% to ensure resources on the margin were not screened out during economic screening. These annual decrement values, along with average market prices, are presented for the Rocky Mountain Power and Pacific Power territories in Figure 25 and Figure 26, respectively.[72] Further information on the derivation of these decrement values is provided in Volume II, Appendix C.
- ***Avoided line losses*.** These vary by state and customer sector. Values are from PacifiCorp's 2004 Transmission and Distribution Loss study and are presented in Table 51.
- ***NW regional conservation credit*.** Ten percent adder for additional benefits of energy efficiency (referred to as "conservation credit" in the Northwest Power and Conservation Council's Power Plan) and recognized by Washington and Idaho. The same credit of 10% was also applied to California to better approximate the "societal" test used in that state.
- ***Discount rate***: Weighted average cost of capital (7.1% per year).

Table 51. Economic Assumptions by State

State	Line Loss		Conservation Credit	IRP Decrement Territory
	Residential/ Commercial	Industrial		
WA	11.0%	7.0%	10%	Pacific Power
CA	11.2%	6.9%	10%	Pacific Power
ID	11.4%	7.1%	10%	Rocky Mt Power
UT	9.7%	6.8%	0%	Rocky Mt Power
WY	9.3%	6.9%	0%	Rocky Mt Power

[72] The decrement cost spike in 2018 is due to the switchover from front-office transactions to combined-cycle growth stations in 2019. This switchover reduced the incidence and associated cost of Energy Not Served associated with the preferred portfolio. Energy Not Served is a condition resulting from stochastic production cost simulations in which there are insufficient resources to meet load in a part of the modeled system.

Figure 25. Rocky Mountain Power Territory Annual IRP Decrement and Market Price Values

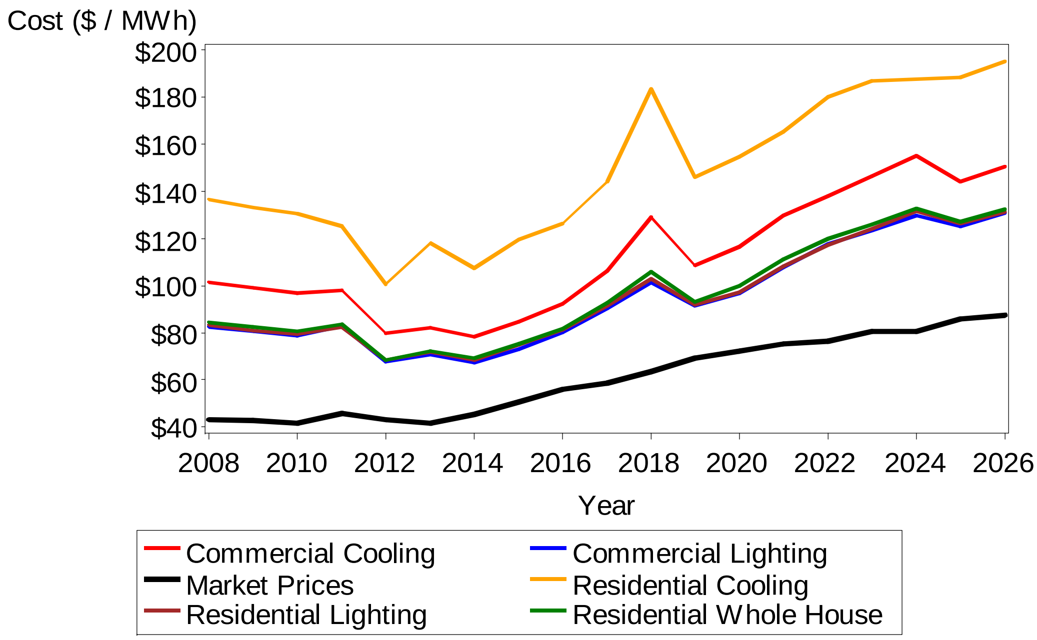
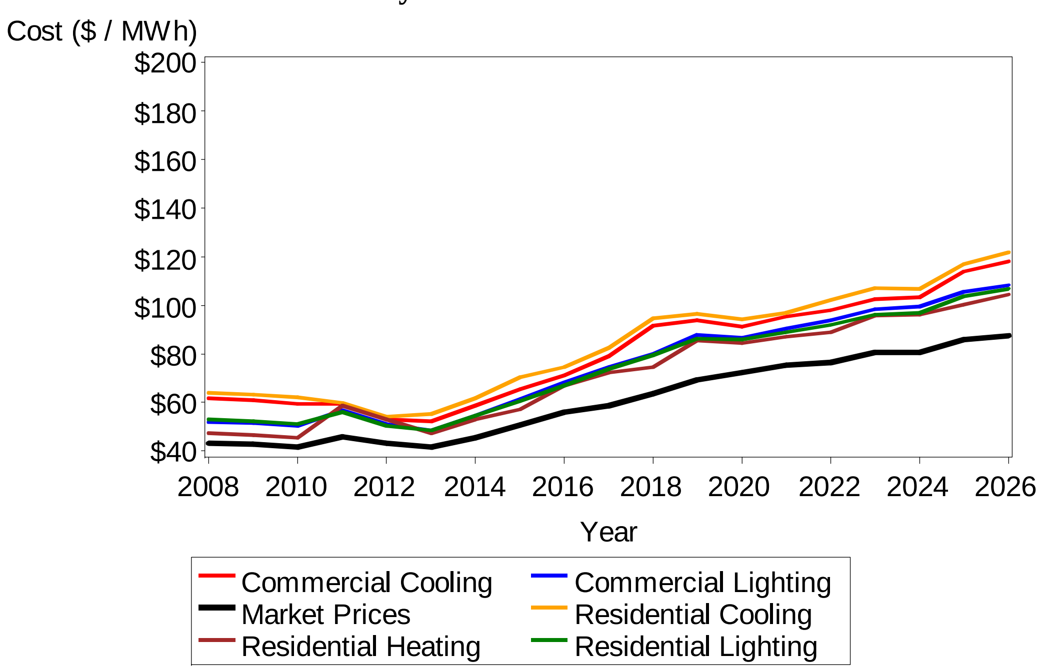


Figure 26. Pacific Power Territory Annual IRP Decrement and Market Price Values



High and low scenarios were built by applying multipliers consistent with the IRP process to the decrement values. On average, the high scenario costs were 48% above the average decrement values over 20 years, while the low scenario values were 30% below the base case. These alternative decrement scenarios were used to produce alternative assessments of both economic and achievable potential, the results of which are presented at the end of this section.

Resource Cost Components. Costs include all expenses associated with implementation of measure installations, including equipment, labor, administration, and any ongoing O&M costs.

Capital measure costs: Variable by measure

- *Installation labor costs*: Variable by measure.
- *Ongoing O&M costs*: Variable by measure. These are generally difficult to quantify, but they were incorporated in situations where they play a significant role in the economic analysis, and existing reliable third-party data were available. This study did not independently estimate any O&M costs. An example of such a measure is scientific irrigation scheduling in the irrigation sector, which has O&M costs each year over the life of the measure that are comparable to capital costs.
- *Discount Rate*: Weighted average cost of capital (7.1% per year) for measures with O&M costs.
- *Administration Costs*: 15% of installed measure costs, escalating at the rate of inflation (1.9%) over the course of the planning period.[73]

Economic Screening Results

There are three important considerations in interpreting the results of economic screening as it relates to assessment of energy-efficiency potential. First, the analysis is based on a TRC perspective and, as such, no assumptions are made as to how measure costs are split between utility and participants in energy-efficiency programs. This consideration has important implications in terms of achievable potential since, in most DSM programs, the utility rarely pays the full incremental cost of the measure.

Second, outcomes of the screening procedure described above depend on assumptions that will likely change over time. Measure costs, for example, are likely to decline over time as the demand for energy-efficient technologies increases. At the same time, the cost of reaching each successive participant can often increase. In addition, the IRP decrement values are likely to change over time, and, as these values change, so do the value of savings resulting from the installation of energy-efficient technologies (i.e., a measure failing the economic screen in earlier years of the planning period may become cost-effective in later years if decrement values increase over the course of the planning horizon).

The third consideration is that the economic analysis is based on assumptions intended to reflect the “average” or “typical” customer. This means that, while a measure might not pass the

[73] Actual administrative costs are based on specific program characteristics. The 15% adder is an assumption based on average historical information and is not a replacement for actual program planning and delivery activities.

economic screen within the context of this study, there could be instances where the measure would be cost-effective. For example, a premium central air conditioner may not be cost-effective in an average single-family home, but, in a larger home with more occupants, this measure could pass the economic screen due to increased savings.

In spite of these caveats, the underlying inputs for this study have undergone thorough review and represent the best information available about specific conditions (regarding both technical measure details and customer attributes) in PacifiCorp's service territory at the time of the study. As with any study of this nature, as more current information becomes available, it can be used to update key drivers, but the current study results are sufficient to inform both the resource planning and program delivery process.

Achievable Potential

Achievable potential is defined as that portion of economic potential expected to be reasonably achievable in the course of the planning horizon. Methods for estimating achievable potential vary across potential assessment efforts. Two dominant approaches appear to be most widely utilized. The first, used in the assessment of energy-efficiency potential in California, is based a hypothesized relationship between incentive levels and market penetration of energy-efficiency programs. The second approach generally relies on a fixed percentage of the economic potential based on past experience of similar programs. For example, in the Northwest, the Northwest Power and Conservation council has historically assumed 85% of the economic potential would be achievable, including savings attributable to changes in codes and standards. Other utilities in the region, such as Puget Sound Energy, Tacoma Power, and Seattle City Light, have used different estimates based on the experience and judgment of program administrators.

The quantity of cost-effective, energy-efficiency potential that is realistically achievable, depends on several factors, including customers' willingness to participate in energy-efficiency programs (which is partially a function of incentive levels), retail energy rates, and a host of market barriers which have historically impeded the adoption of energy-efficiency measures and practices by consumers.[74] These barriers tend to vary depending on customer sector, local energy market conditions, and other, hard-to-quantify factors. However, the central tenet of assessing achievable potential is that it is ultimately a function of the customers' willingness and ability to participate in utility programs, which is best ascertained through direct elicitation from potential participants.

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[74] Consumers' apparent unwillingness to invest in energy efficiency has been attributed to the existence of certain market barriers for energy efficiency. A rich literature exists concerning what has become known as the "market barriers to energy efficiency" debate. Market barriers identified in the energy-efficiency literature fall into five broad classes of market imperfections thought to inhibit investments in energy efficiency: (1) misplaced or split incentives; (2) high front costs and lack of access to financing; (3) lack of information and uncertainty concerning the benefits, costs, and risks of energy-efficiency investments; (4) investment decisions guided by convention and custom: and (5) time and "hassle" factors. For an ample discussion of these barriers, see William H. Golove and Joseph H. Eto, "Market Barriers to Energy Efficiency: A Critical Reappraisal of the Rationale for Public Policies to Promote Energy," Lawrence Berkeley National Laboratory, University of California, Berkeley, California, LBL-38059, March 1996.

The calculation of achievable potential for this study is based on applying a market acceptance factor to the economic potential. Development of this market acceptance factor varies by customer sector. For the C&I sectors, factors were derived directly by surveying 215 of PacifiCorp's C&I customers, with the responses used to determine the likelihood of customer participation in different programs (focusing on the end uses to which the programs would apply) given different levels of incentives (0%, 50%, and 75%). Based on its consistency with typical funding levels, responses to the 50% incentive level were used to develop the base-case achievable scenarios. See Volume II, Appendix A, for a complete description of the methodology and results of these surveys.

For the residential sector, achievable potential is based on two sources. The first source is secondary data from a survey of Northwest utility managers, energy-efficiency consultants, and implementation contractors.[75] The survey asked respondents to estimate achievable potential at different incentive levels. To supplement the survey results, a literature review was conducted to gather estimates of achievable potential from similar studies and other market studies. As in the C&I sectors, the achievable percentages associated with a 50% incentive level are used as the expected achievable scenario.

The levels of achievable potential in each sector and for the commercial sector end use are presented as a percent of the economic potential in Table 52. While the results for the commercial sector varies by the end use associated with the energy-efficiency activities, data for the industrial sector and the complexity of industrial processes indicated the best approach was to use a single average level for all industrial end uses.

Table 52. Assumptions of Achievable Potential as Percent of Economic, by Sector and End Use

Sector/End Use	Existing Construction	New Construction
Residential		
All	50%	38%
Commercial		
Heating	60%	45%
Cooling	59%	44%
Lighting	81%	61%
Water Heat	60%	45%
Other	63%	47%
Industrial and Irrigation		
All	64%	N/A

The survey of experts indicates a lower achievable potential factor in the new construction market mainly due to issues concerning the concept of economically favorable "windows of opportunity" for equipment purchase decisions. The basic idea is that the economic viability of investments in efficient equipment varies with the type and timing of the associated construction activity. The window's size varies depending on the specific equipment in question and the

75 Tacoma Power's 2006 – 2026 Conservation Potential Assessment, Chapter 5 and Appendix A.

timing of the possible purchase and installation. For the utility to influence the project outcome, it must synchronize its efforts with the normal cycle of new construction activity and act within limited windows of opportunity as they become available.

The estimated achievable potential is meant to serve principally as a planning guideline. Acquiring these levels of demand-side resources depends on actual market acceptance of various demand-side technologies and measures, which depend in part on removing barriers, not all of which are completely in the utility's control. Depending on actual experience with various programs in the future, PacifiCorp may consider alternative delivery methods, such as existing market transformation efforts and promotion of codes and standards, to capture portions of these resources. This is particularly relevant in the context of long-term energy-efficiency resource acquisition plans, where incentives might be necessary in the earlier years to motivate acceptance and installations. However, as acceptance increases, so would demand for energy-efficient products and services, which would likely lead to lower costs, obviating the need for incentives and, ultimately, preparing for a transition to codes and standards.

Class 2 DSM Detailed Resource Potential

Residential Sector

Residential customers in PacifiCorp's territory account for about one-quarter of baseline electricity retail sales. The single-family, manufactured, and multifamily dwellings that comprise this sector present a variety of potential savings sources, including equipment efficiency upgrades (e.g., heat pumps, air conditioning), improvements to building shells (e.g., insulation, windows, air sealing), and increases in lighting efficiency.

Based on resources included in this assessment, achievable potential in the residential sector is expected to be 157 aMW over 20 years, corresponding to an 8% reduction (ranging from 7% to 10% by state) of 2027 residential consumption (Table 53). Utah accounts for 64% (101 aMW) of this savings. Overall, savings amount to around 7.9 aMW per year or an annual reduction in baseline residential sector sales of 0.4%.

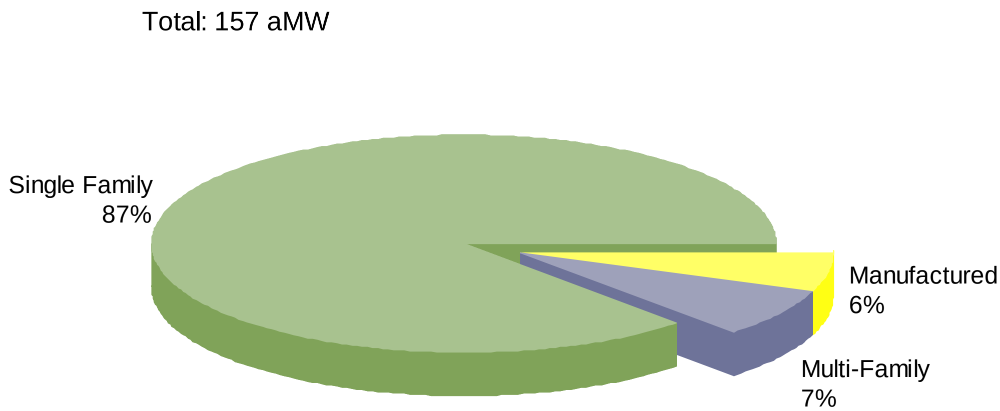
Table 53. Residential Sector Energy-Efficiency Potential by State (aMW in 2027)

State	2027 Baseline Sales	Technical Potential	Economic Potential	Achievable Potential	Achievable As Percent of Baseline Sales	Resource Cost Levelized $/kWh
CA	66	13	10	5	7%	$0.05
ID	147	35	31	14	10%	$0.05
UT	1,382	277	228	101	7%	$0.05
WA	255	58	47	22	9%	$0.05
WY	194	38	34	15	8%	$0.04
Total	**2,043**	**421**	**350**	**157**	**8%**	**$0.05**

Note: Results may not sum to total due to rounding.

As shown in Figure 27, single-family homes represent 87% (137 aMW) of the total achievable residential potential, followed by multifamily (11 aMW) and manufactured homes (9 aMW). The main driver of these results is each home type's proportion of baseline sales, but other factors, such as heating fuel sources, play an important role in determining potential. For example, multifamily homes typically have more electric heating than other home types, which increases their relative share of the potential. On the other hand, the lower use per customer for multifamily units serves to decrease this potential since some measures may not be cost-effective at lower consumption levels. Other factors include varying levels of equipment saturations by state, home type, and weather, as reflected in heating and cooling loads. All specific factors affecting the results are included in the state- and segment-specific data, provided in Volume II, Appendix C.

Figure 27. Residential Sector Achievable Potential by Segment

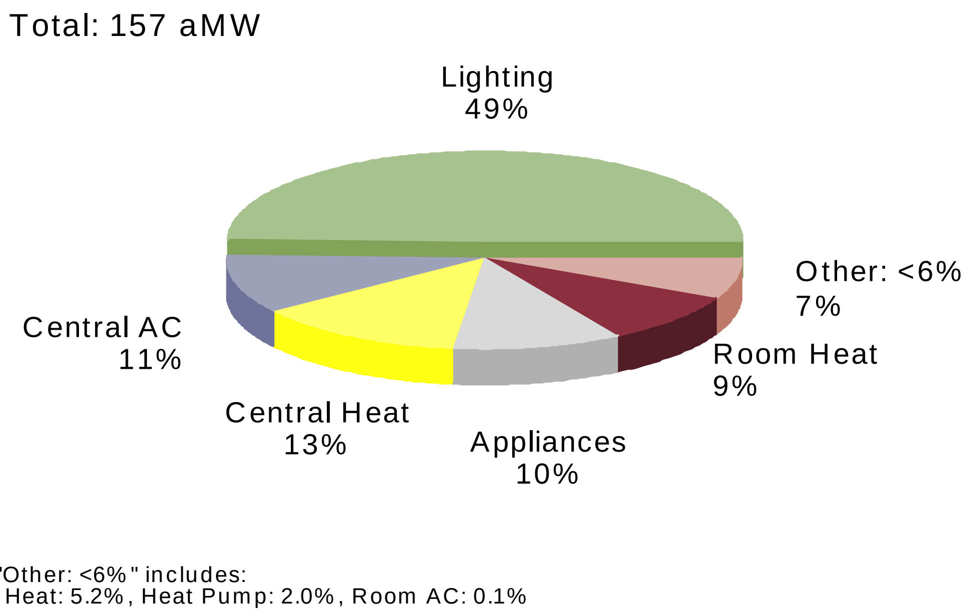


Almost half (49%) of the achievable potential by end use (Figure 28) in the residential sector comes from lighting measures, specifically compact fluorescent lighting. Space heating (central and room) accounts for the next largest slice (22%), followed by air conditioning, freezers (included in appliances and almost exclusively associated with recycling), water heating, and other appliances (see Table 54). These results reflect Utah's large share of the total sales (68%). While the assumptions driving the lighting and appliance savings tend to be consistent throughout the territory, other end uses are affected by customer demographics that vary widely between states, such as the saturation of specific end uses. For example, the vast majority of the central air conditioning component in Figure 28 comes from Utah. The detailed results, which show the savings by individual states and home types – provided in Volume II, Appendix C – reflect the differences in equipment saturations, shares for electricity, and proportions of baseline sales associated with different home types.

Because lighting represents such a large share of residential potential, underlying assumptions and results were compared for consistency with other sources. In addition to other studies conducted by Quantec that show similar shares for lighting, this finding is corroborated by other parties, including studies conducted for the California Measurement Advisory Council, which showed 55% of residential achievable potential was in lighting, and the Vermont Department of

Public Service (indicating 49% of achievable potential).[76] Furthermore, data and assumptions from the Northwest Power and Conservation Council and the NEEA, including the number of fixtures per home, baseline bulb wattage, and typical hours of use, were compared to this effort and were generally found to be consistent.[77] Data regarding existing market penetration of compact fluorescent bulbs, both naturally occurring and due to historical program activity, comes primarily from the Energy Decisions Survey. Finally, it should be noted that several states are considering restricting or eliminating sales of incandescent bulbs in the next five years, and that action would serve to significantly reduce this potential, as described in Section 6.

Figure 28. Residential Sector Achievable Potential by End Use



[76] California Statewide Residential Sector Energy Efficiency Potential Study, Study ID #SW063, April 2003, conducted by Kema/Xenergy and Vermont Electric Energy Efficiency Potential Study - Final Report, January 2007, Conducted by GDS Associates

[77] Total sockets in single-family homes, for example, were estimated at 31 per home for this study, compared to 30 in NEEA's ACE model. Average daily hours of use in this study were assumed to be 2.5 per socket, compared to 2.6 for the NEEA assessment. Average watts for incandescent bulbs were also similar.

Table 54. Residential Sector Energy-Efficiency Potential by End Use (aMW in 2027)

End Use	Baseline Sales	Technical Potential	Economic Potential	Achievable Potential
Central Cooling[78]	158	66	39	17
Central Heat	136	53	45	21
Cooking Oven	48	6	- - -	- - -
Cooking Range	48	- - -	- - -	- - -
Dryer	50	2	2	1
Freezer	53	22	22	11
Heat Pump	28	11	7	3
Lighting	390	171	171	78
Other	16			
Plug Load	800	12	3	1
Refrigerator	97	13	11	4
Room AC	7	1	0	0
Room Heat	102	37	31	14
Water Heat[79]	110	27	20	8
Total	**2,043**	**421**	**350**	**157**

Note: Results may not sum to total due to rounding/

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

Commercial Sector

The commercial sector offers the largest source of opportunities for electric energy-efficiency improvement. This study's results indicate a total of 223 aMW of achievable potential in the commercial sector over 20 years. Similar to the residential sector, this potential is dominated by Utah (72% of achievable potential) and its particular customer demographics.

78 This end use is principally central air conditioning, but it also includes evaporative coolers. Note that more than 40% of the savings (slightly more than 7 aMW) associated with central air conditioning are due to replacement of central systems with evaporative coolers.

79 Savings in water heat include clothes washers and dishwashers (around 25% of the total achievable water heat potential) as the majority of their savings are attributable to reduction in consumption of hot water.

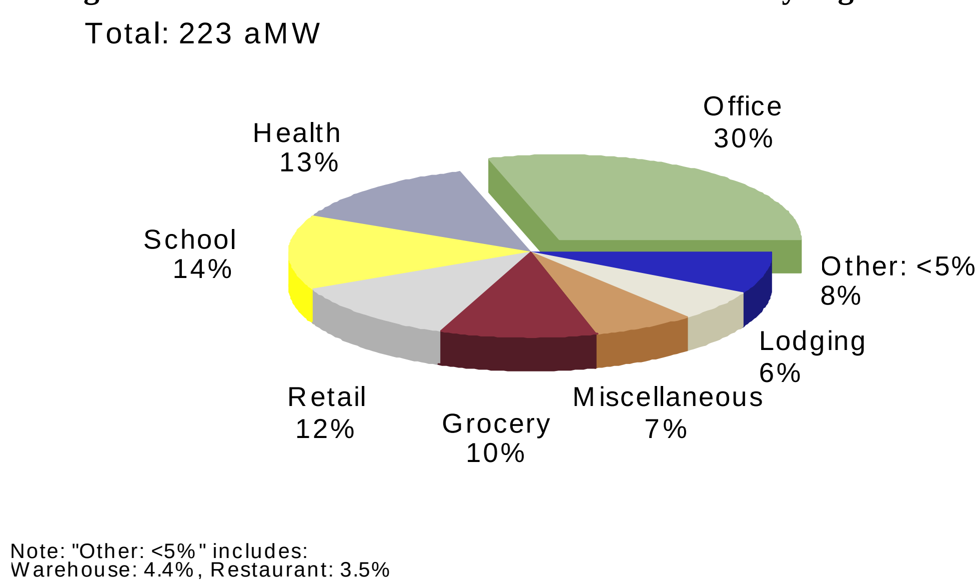
Table 55. Commercial Sector Energy-Efficiency Potential by State (aMW in 2027)

State	Baseline Sales	Technical Potential	Economic Potential	Achievable Potential	Achievable as % of Baseline Sales	Resource Cost Levelized $/kWh
CA	60	12	7	4	7%	$0.03
ID	112	18	14	9	8%	$0.05
UT	1,982	373	270	161	8%	$0.05
WA	239	49	33	20	9%	$0.03
WY	302	60	47	28	9%	$0.04
Total	**2,695**	**511**	**372**	**223**	**8%**	**$0.04**

Note: Results may not sum to total due to rounding

As shown in Figure 29, offices and educational facilities represent the largest shares (30% and 14%, respectively) of savings potential in the commercial sector. Considerable savings opportunities are expected in the commercial sector's health (13%), retail (12%), and grocery (10%) segments. Moderate savings amounts are expected to be available in lodging facilities, warehouses, restaurants, and miscellaneous buildings types such as churches, assembly halls, and fitness centers. As discussed previously, Utah's largely urban customer population, with a substantial proportion of both small and large-office segments, is the main driver behind these results. Detailed information regarding the commercial sector potential achievable within each state is provided in Volume II, Appendix C.

Figure 29. Commercial Sector Achievable Potential by Segment



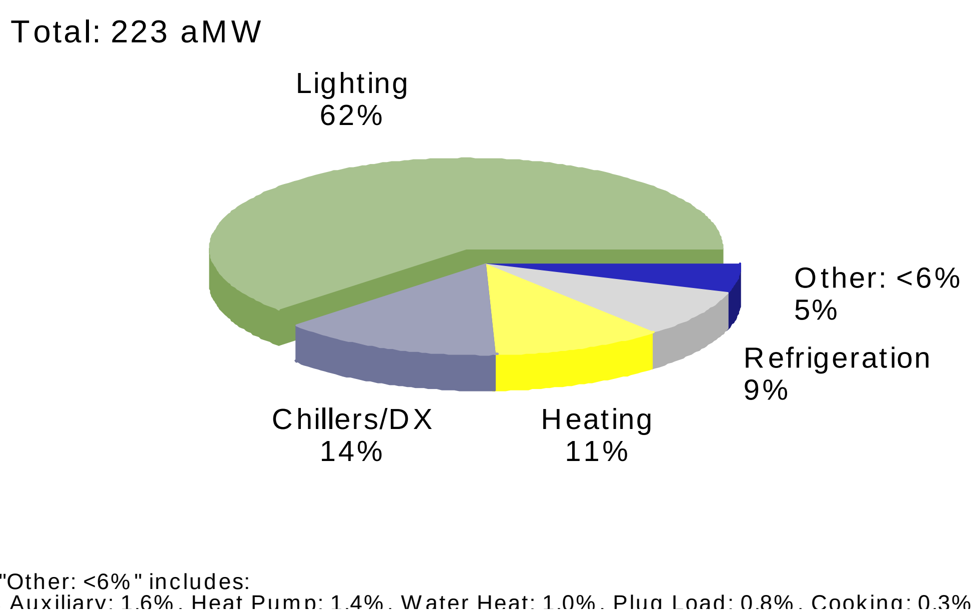
As in the residential sector, lighting efficiency represents by far the largest portion of achievable potential in the commercial sector (62%), followed by cooling (14%), heating (11%), and other non-HVAC end uses (11%), as shown in Table 56 and Figure 30. Several factors contribute to the large achievable lighting potential. First, Utah has a large number of offices that contribute to lighting consumption. Second, lighting tends to be cost-effective, and, in this case, the economic potential represents more than 86% of the technical potential (Table 56). Finally, lighting retrofits are widely accepted in the market, as evidenced by the survey results for PacifiCorp's commercial customers. One caveat to these results is there is an increasing trend in commercial codes towards lower power density; so the most appropriate means of acquisition for this resource might be through codes and standards. Scenarios of this nature are discussed more thoroughly in Section 6.

Table 56. Commercial Sector Energy-Efficiency Potential by End Use (aMW in 2027)

End Use	Baseline Sales	Technical Potential	Economic Potential	Achievable Potential
Cooking	22.7	1.6	1.3	0.7
Cooling Chillers	31.3	17.5	10.7	4.9
Cooling DX	192.0	91.1	54.3	25.8
HVAC Auxiliary	620.2	37.0	9.6	3.5
Heat Pump	28.0	11.1	6.2	3.1
Lighting	1,219.9	236.2	203.3	138.1
Plug Load	177.8	5.0	3.3	1.7
Refrigeration	211.1	37.6	34.7	19.2
Space Heat	155.8	61.9	44.0	23.8
Water Heat	36.0	12.4	4.5	2.2
Total	**2,694.9**	**511.4**	**371.9**	**223.1**

Note: Results may not sum to total due to rounding

Figure 30. Commercial Sector Achievable Potential by End Use



Industrial Sector

Technical, economic, and achievable energy-efficiency potential was estimated for major end uses within 14 major industrial sectors in PacifiCorp's service territory. These customer sectors correspond to the load forecast as close as practically possible. Achievable energy-efficiency potential in the industrial sector is estimated at 114 aMW, representing approximately 5% of the total industrial load in 2027. The chemicals industry represents the largest percentage (26%) of the achievable potential (Table 57).

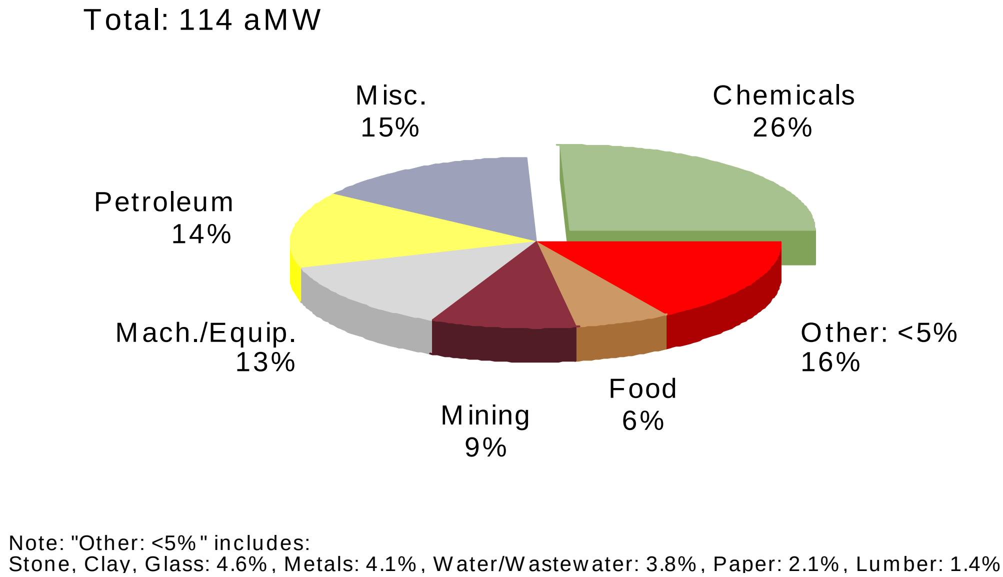
Table 57. Industrial Sector Energy-Efficiency Potential by State (aMW in 2027)

State	Baseline Sales	Technical Potential	Economic Potential	Achievable Potential	Achievable as % of Baseline Sales	Resource Cost Levelized $/kWh
CA	9	1	1	1	7%	$0.02
ID	36	4	4	3	7%	$0.01
UT	1,011	101	101	64	6%	$0.01
WA	154	12	12	8	5%	$0.02
WY	1,031	60	60	38	4%	$0.01
Total	**2,242**	**178**	**177**	**114**	**5%**	**$0.01**

Note: Results may not sum to total due to rounding

In examining these aggregate results for the industrial sector, there should be some caution in associating summary potential information for a particular facility type to individual states. While nearly all residential and commercial customer segments were present in every state, some of facility types in the industrial sector applied to as few as one state. The machinery and equipment manufacturing potential, for example, is exclusive to Utah. The state- and industry-specific results are provided in Volume II, Appendix C.

Figure 31. Industrial Sector Achievable Potential by Segment



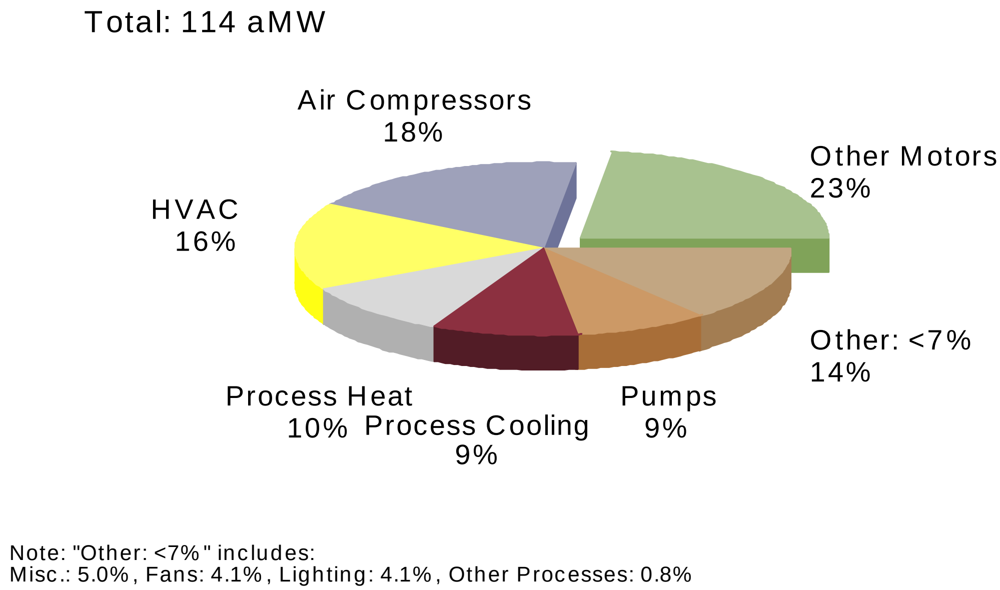
The majority of savings in the industrial sector (54%) are attributable to efficiency gains in motor upgrades, air compression, pumping, air distribution, and other motors, which include motors in mining applications. Because many motors used in mining do not fit into traditional industrial motor categories, they have been classified into "Other Motors;" thus, this slice of the potential is large (24 aMW). The remaining potential is split between HVAC[80] and other building improvements, process improvements, and lighting (Table 58 and Figure 32).

Table 58. Industrial Sector Energy-Efficiency Potential by End Use (aMW in 2027)

End Use	Baseline Sales	Technical Potential	Economic Potential	Achievable Potential
Fans	105	7	7	5
HVAC	162	29	29	19
Indirect Boiler	44	---	---	---
Lighting	122	7	7	5
Motors - Other	878	37	37	24
Other	58	9	9	6
Process				
Air Compressors	153	33	33	21
Cooling	105	17	17	11
Electro-Chemical	102	---	---	---
Heat	142	18	18	11
Other Processes	130	1	1	1
Refrigeration	54	4	4	2
Pumps	187	16	16	10
Total	**2,242**	**178**	**177**	**114**

80 A substantial portion of industrial HVAC savings come from clean room applications.

Figure 32. Industrial Sector Achievable Potential by End Use



Irrigation Sector

Although irrigation potential is small compared to the other industries, it is estimated 6% of 2027 usage could be achievable, with more than half the savings in Idaho. Electricity consumption in the irrigation sector consists primarily of motors used for pumping, with a much smaller portion going to miscellaneous non-pumping end uses. As a result, all irrigation potential consists of measures that improve pumping efficiency, including pump upgrades, motor upgrades, and efficient nozzles. The cumulative aMW savings in 2027 associated with these measures are presented in Table 59.

Table 59. Irrigation Sector Energy-Efficiency Potential by State (aMW in 2027)

State	Baseline Sales	Technical Potential	Economic Potential	Achievable Potential	Achievable as % of Baseline Sales	Resource Cost Levelized $/kWh
CA	10.8	1.7	1.1	0.7	6%	$0.03
ID	72.9	11.3	7.9	4.6	6%	$0.03
UT	26.7	4.1	2.6	1.7	6%	$0.03
WA	19.3	3.0	1.9	1.2	6%	$0.03
WY	2.2	0.3	0.2	0.1	6%	$0.03
Total	131.8	20.4	13.7	8.3	6%	$0.03

Note: Results may not sum to total due to rounding

Irrigation savings originate from mainly reduced pump motor energy use, which may be achieved from reduced pressure, flow,[81] or both. Identified savings may therefore be achieved by alternative measures such as nozzles upgrades. The magnitude of savings is also directly related to pump lift (total dynamic head), which varies across different service territories. This factor is a critical consideration in delivering cost-effective programs in this sector, which are likely more effective in jurisdictions such as Idaho, where deep wells tend to be the more common sources for irrigation water.

[81] This includes scientific irrigation scheduling (SIS), which saves energy by minimizing the amount of irrigation required.

4. Education and Information (Class 4 DSM)

Scope of Analysis

Consumer education and dissemination of information on energy use have been the oldest strategies for promoting energy efficiency, particularly in the residential sector. Although these programs are run by many utilities and public agencies across the country, very few rigorous assessments of their energy savings have been undertaken. Due to the difficulties in measurement and verification of their savings and the lack of reliability relative to other DSM and traditional supply-side resources, this class of resources is generally not included in utility integrated resource planning.

In order to investigate the potential for and effectiveness of program options in this area, research was conducted to collect information on program structures, delivery strategies, costs, and potential impacts of education and information programs in the United States. The results of this research are summarized below. A detailed annotated bibliography of program plans and evaluation reports concerning the referenced programs may be found in Volume II, Appendix D.

Consistent with the definitions used in PacifiCorp's integrated resource planning process, Class 4 DSM resources comprise energy and/or capacity reductions achieved through behavioral changes brought about through information and education programs and campaigns. Among the various Class 4 DSM programs currently offered, there are three basic categories (Table 60).

Table 60. Class 4 DSM Activity Types

Program Type	Intended Impact	Identifiable Participants	Activities
Non-Targeted			
Non-targeted campaigns: Capacity-focused	Capacity focused	No (non-targeted)	Media advertisements, email and fax alerts
Non-targeted - Energy efficiency	Energy efficiency	No (non-targeted)	Bill inserts, media advertisements
Targeted			
Education and Energy Efficiency Programs	Energy efficiency	Yes (Targeted to certain populations such as school based and low income	Short-term classes, training programs

The first group promotes a capacity-focused response by actively encouraging a reduction in energy demand, typically in the short-term. The second group of programs promotes the adoption of on-going energy-efficiency practices. Both program types are advertised and promoted to a wide audience. These two groups are called "non-targeted" as there is no distribution list of recipients, and the promotional messages are disseminated broadly. The final group of programs also encourages the use of more energy efficient practices and equipment, but the message is delivered to a specific audience. For this reason, they are called "targeted" programs.

A further distinction may be made as to the intended impact of a program – to encourage short-term actions during peak demand (capacity-focused) or to encourage energy efficiency through changes in behaviors or the installation of technologies (energy efficiency). A number of programs are designed to accomplish both objectives.

Non-Targeted Campaigns – Capacity-Focused and Energy Efficiency

A non-targeted capacity-focused campaign is designed to promote an immediate response to reduce current electricity demand. In such a program, the need for short-term demand reduction is publicized in the general media and may also be distributed via email or similar means to customers who have agreed to receive such alerts. Although many programs are being offered nationally (see Volume II, Appendix D), very few report on savings and/or costs. Significant program examples include:

- ***Power Forward (June 1-September 15)*** **–** Power Forward is a Utah state-wide program sponsored by the Utah Department of Environmental Quality and Utah's electric utilities. As part of the program, each day is classified on a day-ahead basis as either a "Green," "Yellow," or "Red" alert day, based upon the forecasted temperature, energy demand and expected market prices. "Green" days are considered business as usual, and customers are requested to follow "normal conservation" actions such as setting their appliances to "energy efficiency" modes when possible. On "Yellow" days, customers are requested to curtail their usage and shift non-essential loads to off-peak hours where possible. "Red" days signal a system emergency and customers are directed to immediately shut down all non-essential loads to avoid possible service interruptions. In 2006, 21 "Yellow" days were called in June and July. No "Red" alert days were required. The total annual cost to PacifiCorp/Rocky Mountain Power is $50,000.
- ***Flex Your Power Now!*** **-** Flex Your Power Now! is a California state-wide program that alerts commercial and residential customers of a short-term need to reduce energy consumption. Like Power Forward, alerts are issued on days when the state's peak energy demand is high, in an effort to reduce the chance of a Stage One electrical emergency. This need is determined by the state Independent System Operator. It is estimated that, in 2006, this program produced 150 MW in load reduction (approximately 0.3% of peak[82]) at a total cost of $5,000,000.[83]

A non-targeted energy-efficiency campaign is a general public outreach campaign that may be directed at residential and/or business consumers. These campaigns are designed to promote sustained behavioral and technological change, rather than the short-term actions prescribed in the capacity-focused programs, such as Power Forward and Flex Your Power Now!. Outreach efforts may include media promotions such as billboards, websites, and television/radio ads. Other outreach methods such as bill inserts, website information, and electronic mail to utility customers may also be included in this category. Program examples include:

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[82] On July 25, 2006, California peak demand reached a new record high of 50,538 MW. CAISO Press release 7/25/06.

[83] Wally McGuire, Flex Your Power, email correspondence. February 2007.

- ***Do The Bright Thing.* –** "Do the Bright Thing" is the general name for PacifiCorp's on-going consumer education program, for the both commercial and residential sectors. The campaign is designed to educate consumers about the benefits of adopting energy-efficiency measures and promotes energy-saving ideas.
- ***Flex Your Power* –** A non-targeted conservation campaign called "Flex Your Power" operates in conjunction with the capacity-focused program "Flex Your Power Now!" This non-targeted conservation program includes a general consumer awareness campaign geared toward the promotion of energy-efficiency activities. The program was first launched in 2001. The campaign reported an estimated reduced peak electricity demand of 6,369 MW, of which 2,616 MW were credited to voluntary conservation savings.[84] According to the Energy Services Bulletin, Flex Your Power reduced California's energy consumption at peak by as much as 14% during the summer of 2001.[85]

Targeted Education and Energy Efficiency

This category of programs includes training and class work for adult learners such as professional development courses and workshops, and more broad-based educational programs. It also includes school-based energy-efficiency curriculum provided directly in the classroom. Examples of programs in this category include the following.

- ***The Pacific Power Low-Income Bill Assistance Adult Education Pilot Program, Year Two (2005-'06)* –** This pilot program provided energy education to income-eligible households in the State of Washington. Participant families attended a workshop on energy saving measures and received a range of energy-efficiency measures. Based upon an evaluation conducted in 2006, average initial impact of the educational component of this program was estimated at 337 kWh per household, representing about a 1.5% reduction in annual consumption. These savings proved to diminish over time following the completion of the education program.[86]
- ***The Iowa Energy Wise Program (2004-'05)* –** Iowa Energy Wise is an adult education program targeted to low-income households. Program participants attended classes and received energy-saving fixtures (e.g., compact fluorescent light bulbs). An impact evaluation of this program, conducted by Quantec in 2006, indicated energy savings from behavioral changes of 79 kWh per participant, representing approximately 0.6% of normal annual consumption.[87]
- ***Better Buildings, Better Business Conference, Energy Center of Wisconsin (2006)* –** This one-day technical training conference is attended by professionals in the building

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[84] California Energy Commission, 2001

[85] Energy Services Bulletin, Vol. 23, No. 6, December 2004.

[86] Quantec evaluation, January 2007. Cost is given per household, with 1,436 participating households. Savings based upon educational component of program only, as indicated in participant surveys.

[87] Quantec evaluation, December 2005. 990 participants. Of the total energy savings realized, 18% were attributed to adopted changes in behavior; balance (350 kWh) were attributed to specific installed energy measures. Cost shown for education-related efforts are also estimated to be 18% of the total cost.

trades and provides specific hands-on workshops and training in the building sciences. Staff at the Energy Center of Wisconsin surveyed conference participants to determine which new practices had been adopted and the resulting energy savings. Participants reported saving 61,500 kWh in the year following the conference after adopting one or more of the practices that they had learned in attendance.[88]

- ***Hydro One Real-Time Monitoring Pilot (2004-'06)* –** Hydro One (Ontario) undertook a two-year pilot program to determine if real-time information about the consumption of energy would lead to reduced energy consumption. Participants were provided with Power Cost Monitors that display how much energy is being consumed and the associated cost. Four hundred pilot and control participants took part over a 2.5-year period of time. The study concluded that the aggregate savings in electricity consumption (kWh) was 6.5%.[89] The study further concluded that the participant action to reduce energy consumption remained throughout the program period.
- ***Compressed Air Challenge Training Program* –** Offered by the US Department of Energy (DOE), this training program is designed for industrial plant personnel and compressed air vendors. As of May 2001, approximately 4,000 people had attended either the Fundamental or Advanced compressed air training. Savings per program participant have been estimated at an average of 149 MWh per year, or approximately 7.5% of pre-project system energy.[90] This significant level of savings speaks to the target group of program participants, many of whom were employed at large industrial user companies.
- ***San Diego Green Action Program (2004-'05)* –** A multi-faceted education program that included energy education workshops, energy audit training, and a youth forum. Approximately 1,500 students participated in an energy education class and an energy audit of their school, where they learned how to conduct a home energy audit. Program expenditures were $330,000 in 2004-'05. However, the savings were not estimated because the program is classified as a "non-resource program" and is not designed for resource acquisition.[91]
- ***Ohio Home Weatherization Assistance Program Client Education Pilot Program* –** In-home educational visits provided in addition to the installation of weatherization services. The target population was divided into two groups. Group 1 (296 households) received weatherization and in-home education, while Group 2 (301 households) received the weatherization services alone. Evaluation of this program has estimated a 14% reduction in electricity use and found that 6.7% of the savings could be attributed to the educational component of the program.

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88 Ingo Bensch, et al. "How Much Is that Training Program Worth? Quantifying the Value of Training and Other 'Fuzzy' Education Events." 2006. ACEEE.

89 Dean Mountain, March 2006. The Impact of Real-Time Feedback on Residential Electricity Consumption: The Hydro One Pilot.

90 Lawrence Berkeley National Laboratory and Xenergy. "Evaluation of the Compressed air Challenge Training Program." March 2004.

91 www.sdenergy.org/uploads/PIP_2004_Green%20Action.pdf

Potential and Costs

Information on energy savings impacts and costs was obtained through extensive research reviewing existing program plans, regulatory filings, and evaluation reports pertaining to Class 4 DSM programs. Program planners and implementers at a number of different utilities and agencies were contacted, including the Power Forward Partnership of Utah, Flex Your Power, the Energy Center of Wisconsin, the San Diego Green Action Program, NYSERDA, BC Hydro, and Hydro One (Ontario).

The results of this research indicated that actual impacts of these programs tend to be hard to measure due to education and information services being offered in conjunction with energy-efficient measures and equipment (e.g., light bulbs, shower heads, flow restrictors), which would then be considered a Class 2 DSM resource. Only in a few cases did evaluation reports provide information on the isolated impacts of the education and information components of these programs. Estimates of program savings and costs are often reported on a different basis, which makes comparing results impossible. For example, costs may be reported in terms of total program, per participants, or per unit of energy savings; savings may be reported in absolute terms or relative to total annual consumption.

The available information on the majority of Class 4 DSM programs, discussed above, also indicate a wide range in estimated savings and costs. The evidence on the experiences of these programs generally indicates the presence of a positive, albeit small, effect from these programs in producing modest amounts of savings at a relatively low cost. Several recent variations of these programs, such as the Ontario Hydro One Real-Time Monitoring Program may be an example for changing the direction of these programs campaigns. By supplying consumers with the Power Cost or Home Energy Monitors at a fairly low cost (each monitor is less than $150), the homeowner gains real-time feedback on energy use and cost. Fairly substantial savings (5%-10%), entirely from behavioral modification, have been found by using these monitors in pilot studies. A pilot program in Portland is planned by the Future of Efficiency group to take place within 2007, which could provide better feedback on the usefulness of such an approach in the Northwest.

Based on the data collected for this assessment, it appears reasonable to assume that, if well conceived and effectively delivered, residential programs of this type have the potential to reduce participants' consumption by approximately 1% to 3%, for 5% to 10% of the population that choose to participate.

Table 61 provides a range of potential energy saving impacts resulting from Class 4 DSM programs in the residential sector. Estimated savings are given by utility service territory.

Table 61. Estimated Residential Impacts of Class 4 DSM Programs (aMW)

Territory	Low Impact		High Impact	
	2027 aMW	% Territory Load	2027 aMW	% Territory Load
Rocky Mountain Power	0.8	0.05%	4.7	0.30%
Pacific Power	0.5	0.05%	3.3	0.30%

Potential impacts on the commercial side could range from one tenth of one percent (0.10%) to as much as 2%. See Table 62 for a summary of potential impacts in the commercial sector resulting from Class 4 DSM programs. No projections are given here based on Class 4 DSM programs for industrial use. As the experience of the Power Forward during the summer of 2006 showed, peak capacity reductions may also be realized through these programs. However, these impacts tend to be situation-specific and their actual levels are difficult to predict.

Table 62. Estimated Commercial Impacts of Class 4 DSM Programs (aMW)

Territory	% Estimated Impact				
	0.10%	0.50%	1.00%	1.50%	2.00%
Rocky Mountain Power	2.2	10.8	21.6	32.4	43.3
Pacific Power	1.0	4.9	9.8	14.6	19.5

Despite their overall educational value and their potential to produce modest amounts of short-term energy and capacity savings, the effects of Class 4 DSM initiatives are difficult to predict and unlikely to persist long after the intervention ceases; as such, they are not well-suited for the purpose of integrated resource planning but rather lend themselves when needed as reliability tools.

5. Supplemental Resources

Scope of Analysis

In addition to traditional capacity-focused and energy-efficiency resources, this report includes an analysis of other resources not considered in the standard definitions of PacifiCorp's demand-side resource classes 1, 2, 3, or 4. These resources, which may be loosely defined as "dispersed generation," resources are considered "supplemental" to this study's initial scope and include the following:

Combined Heat and Power (CHP) units generate electricity and utilize waste heat for space or water heating requirements. They can be used in nearly any building that has a fairly coincident thermal and electric load or produces combustible biomass or biogas. CHP units have been traditionally installed in hospitals, schools, and manufacturing facilities, but they can be used across nearly all segments that have an average annual energy load greater than about 30 kW. CHP is broadly divided into sub-categories, based on the fuel used. Non-renewable CHP runs on natural gas, while renewable CHP runs on a biologically derived fuel (biomass or biogas).

On-Site Solar encompasses both electricity generation and energy-efficiency measures that use solar energy. Three solar related resources are analyzed: on-site solar electric generation or building photovoltaics (PV), and two solar efficiency measures, solar water heaters and solar attic fans.

Dispatchable Standby Generation (DSG) are on-site backup generators that are owned by customers but managed by the utility to provide peak load reduction. Typically, the utility contracts with a customer who owns or will be installing a backup generator, agreeing to pay all interconnection costs, as well as annual fuel and other O&M costs. In exchange, the utility is able to activate the generator for up to 400 hours/year (typically) during peak periods The potential from DSG can come from existing or, as is generally the case, new (yet-to-be installed) backup generators.

Assessment Methodology

The overall methodology to calculate the potential is as follows:

1. Separately calculate ***technical potential*** for each of the resource categories, using the following key data inputs:
    - *CHP*: PacifiCorp's C&I customer database for "typical" building energy loads and service territory (Rocky Mountain Power and Pacific Power) demographics
    - *DSG*: calibrated load shapes and customer peak demand loads, similar to Class 1 and Class 3 DSM resources
    - *Building PV*: customer counts and square footage assumptions
    - *Solar Efficiency Measures*: technical feasibility factors, similar to Class 2 DSM resources

2. Calculate costs of various technologies given literature values, available databases, other states' programs, and, for CHP and DSG, a fuel price.
3. Determine market potential for each resource class based on other programmatic successes and, for CHP, survey results. Note that not all of the market potential is economic and, therefore, may not be achievable.
4. Determine achievable potential by only including the portion of market potential that is economic.

Resource Potential

To correctly estimate the quantity of potential in the market, it is essential to know the penetration of technology currently found in marketplace. The currently installed capacity was obtained from existing databases,[92,93,94] net metering data, and the Energy Trust of Oregon (ETO). The currently installed capacity, by state, is given in Table 63. This capacity excludes the large "central-station" CHP generation facilities and the large "non-net metered" PV generation facilities (such as Oregon's 130 kW Pepsi Cola bottling facility). A full list of each CHP site by state is given in Volume II, Appendix E. Insufficient data exist for installed capacity of DSG units and solar-efficiency measures.

Table 63. Supplemental Resources Installed Capacity by State and Resource Category (MW)

	CA	ID	OR	UT	WA	WY	Total
CHP: Non-Renewable	---	---	18	41	---	12	71
CHP: Renewable	---	3	237	11	1	37	289
On-Site Solar: Photovoltaics	0	---	1	0	0	0	1
Total	**0**	**3**	**256**	**52**	**1**	**49**	**361**

Note: Results may not sum to total due to rounding. "0" indicates an installed capacity less than 0.5 MW

Technical Potential

The technical potential from the energy-focused resources (CHP and on-site solar) is incremental to existing capacity[95] and calculated to be 8,128 aMW in 2027; shown by territory and resource in Table 64.

For CHP, the total potential from non-renewable and renewable units is 4,588 aMW, representing 56% of 2027 energy-focused potential. On-site solar provides 3,537 aMW,

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

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

94 http://www.chpcenternw.org/ and http://www.intermountainchp.org/

95 PacifiCorp accounts for existing CHP in their 2007 IRP load and resource for 2007 through 2016.

primarily building PV, while the solar efficiency measures only account for nearly 3 aMW.[96] DSG, as a capacity-focused resource, has a technical potential of 1,566 MW, two-thirds of which comes from new installations. It should be recognized that the technical potential for the supplemental resources are significantly higher than what could be achieved, largely since upfront costs are quite considerable. This is discussed further below.

Table 64. Supplemental Resources Technical Potential by Region and Resource Category (aMW and MW in 2027)

Technical Potential	Rock Mountain Power	Pacific Power	PacifiCorp System
Energy-Focused (aMW)			
CHP: Non-Renewable	2,434	718	3,152
CHP: Renewable	866	570	1,436
On-Site Solar: Photovoltaics	2,342	1,195	3,537
On-Site Solar: Efficiency Measures	1	2	3
Total Energy	***5,643***	***2,485***	***8,128***
Capacity-Focused (MW)			
DSG: Existing	351	172	523
DSG: New	774	268	1,043
Total Capacity	***1,125***	***440***	***1,566***

Note: Results may not sum to total due to rounding

Achievable Potential

The achievable potential represents the economic portion of the market potential. To determine what resources are economic, the levelized cost of the resource is compared to the levelized market price within the two territories. These levelized costs are given in Table 65, with an indication of whether they pass the economic screens. Note that no on-site solar resources are economic and only some of the non-renewable CHP is economically viable.

96 It should be noted that, for the solar efficiency measures, the technical potential accounts for the share of customers with electric end uses. For example, in Utah the large majority of domestic hot water heating is done by natural gas.

Table 65. Levelized Cost for Supplemental Resources and Economic Screen by Territory

Resource	Levelized Cost	Economic Screen	
		Rocky Mountain Power	Pacific Power
Energy-Focused ($/kWh)			
CHP: Non-Renewable	$0.08-0.16	Partial	Partial
CHP: Renewable	$0.03-0.07	Pass	Pass
On-Site Solar: Photovoltaics	$0.76-0.90	- - -	- - -
On-Site Solar: Efficiency Measures	$0.33-7.91	- - -	- - -
Capacity-Focused ($/kW-year)			
DSG: Existing	$0.61	Pass	- - -
DSG: New	$0.52	Pass	Pass

The achievable potential for all supplemental resources is given in Table 66, by region. As compared to the technical potential (Table 64), this potential is significantly less due to economic considerations, low awareness of technologies, and other permitting, siting, and/or interconnection concerns (details provided in results sections below). Note that the on-site solar measures are not economic and thus not achievable, but an indication of their market potential is provided later.

Table 66. Achievable Potential for Supplemental Resources by Territory (aMW and MW in 2027)

Achievable Potential	Rock Mountain Power	Pacific Power	PacifiCorp System
Energy-Focused (aMW)			
CHP: Non-Renewable	43	16	59
CHP: Renewable	48	31	78
On-Site Solar: Photovoltaics	---	---	---
On-Site Solar: Efficiency Measures	---	---	---
Total Energy	***90***	***47***	***137***
Capacity-Focused (MW)			
DSG: Existing	34	---	34
DSG: New	76	26	102
Total Capacity	***110***	***26***	***136***

Note: Results may not sum to total due to rounding

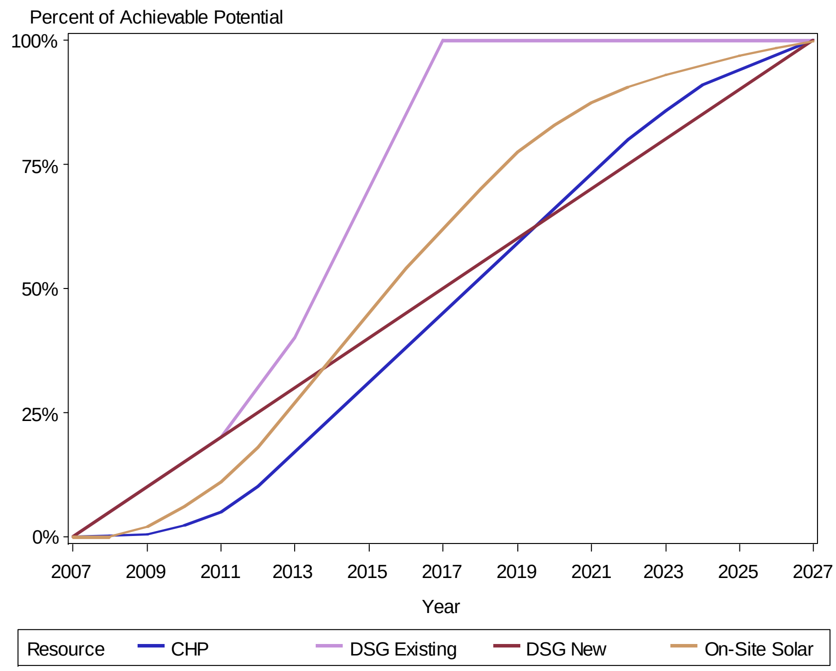
Resource Acquisition Schedule

The assumed resource acquisition rates of all supplemental resource potential are given in Figure 33, with each year’s savings shown as a percentage of the total potential in 2027.

For CHP, this ramp rate has slow growth in the first five years, reflecting the time required for program development, typical sales cycles, and individual capital project timelines with stronger growth in years five through fifteen.[97] For DSG, the acquisition rate is different for new and existing installations. For new installations, the growth of DSG is linear over the 20-year period, reflecting the assumption that new generators are installed at a constant rate over time.[98] The potential adoption rate for existing installations is consistent with the Class 3 DSM resources, where the potential rises at an increasing rate until 2017, when the increases are based solely on load forecast increases.

Finally, for solar resources, particularly PV, existing state programs across the country have had relatively slow growth for the first four years, with an increase in the fifth year, followed by continued and steady growth.[99] Since Oregon, Utah, and Washington either have or are developing PV programs,[100] they influence the market penetration curve, accelerating the overall growth rate. Other states within the PacifiCorp system that do not currently have any programs would likely see a slower growth rate.

Figure 33. Acquisition Schedule for Supplemental Resources by Resource Category



97 This is based on the California Self-Generation Incentive Program having seen a fairly constant number of applicants each year (except for the first year). After year 15, the growth tapers off due to market saturation.

98 However, it may be influenced by the rate of new generator purchases. Based on the October 2006 Diesel and Gas Turbine Worldwide 30th Power Generation Order Survey, from 2004-2006, the number of standby generators ordered has increased approximately 20% each year within North America. (Unfortunately, this survey does not give greater geographical resolution.) This indicates that, at least within the short term, there are increases in market penetration of new standby generators being installed and PacifiCorp could choose to accelerate the adoption to monopolize on this.

99 Data from New Jersey, Connecticut, California, and Oregon was used, and no data exists for more than ten years of program history.

100 In Oregon, the solar programs are through the ETO; in Utah, Rocky Mountain Power has recently begun a pilot PV program and in Washington, the state is mandating the utilities provide a PV incentive.

Resource Potential under Alternative Scenarios

The potential for supplemental resources is analyzed under three economic scenarios (defined in terms of high, base, and low avoided costs) and two achievable scenarios (defined in terms of expected and high-case market penetration). The different economic and achievable scenarios are defined in the context of the capacity-focused and energy-focused resources in Sections 2 and 3 of this report.

Table 67 summarizes the potential for supplemental resources under the six different scenarios for CHP and DSG. On-site solar is not included here, as this resource does not pass the economic screen, even under the high avoided cost scenario. Higher levels of market penetration would require higher incentive levels and marketing effort and thus, it stands to reason, higher administrative costs. However, for the purpose of this analysis, it is assumed that the average per-unit cost of the resources will remain fixed.

Table 67. Economic and Achievable Scenarios: Achievable Potential (aMW and MW in 2027)

		Economic Scenario		
		Base	High	Low
Rocky Mountain Power				
CHP (aMW)	Expected Achievable	90	90	45
	High Achievable	112	112	56
DSG (MW)	Expected Achievable	110	110	110
	High Achievable	165	165	165
Pacific Power				
CHP (aMW)	Expected Achievable	47	48	30
	High Achievable	59	60	38
DSG (MW)	Expected Achievable	26	43	---
	High Achievable	39	65	---

Combined Heat and Power Results

Combined Heat and Power encompasses all technologies that generate both electricity and heat on-site at a customer's facility. Generally, the power generated through these technologies is expected to contribute to the utility's base load resources, rather than peak load requirements. Peak load reduction with an on-site generator, or dispatchable standby generation, is treated separately. CHP has traditionally been installed in hospitals, schools, and manufacturing facilities, but can be used across nearly all facilities that have a fairly coincident electric and thermal load and an average annual energy load greater than about 30 kW. CHP is broadly divided into non-renewable and renewable sub-categories, based on the fuel used.

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

The three primary generator technologies available in the market are 1) reciprocating engines (either spark-ignition or compression-ignition), 2) turbines (gas or steam for larger capacity (>1 MW) or microturbines for smaller capacity (<1 MW)), and 3) fuel cells, primarily those using phosphoric acid (PAFC) or molten carbonate (MCFC) as the electrolyte, although other types of fuel cells are now becoming commercially viable.[101]

CHP is divided into two broad categories, depending on the fuel source. The fuel used for CHP can be from a renewable source (biomass or biogas) or a non-renewable source (natural gas). The same generators described above can be used with either fuel type.

Renewable Generation. In this study, renewable CHP includes all generation using a biomass-based fuel: anaerobic digesters and industrial biomass. Anaerobic digesters create methane gas (biogas fuel) by breaking down liquid or solid biological waste. The captured waste heat of the CHP unit is, in part, used to maintain the high temperature required of the digesters themselves.

Industrial biomass, on the other hand, includes the waste product from industries such as lumber mills or pulp and paper manufacturing, which is combusted in place of natural gas or other fuel. For solid industrial biomass, the heat produced from combustion is often used to run a steam turbine.[102]

Anaerobic digesters are coupled with smaller scale generators, such as reciprocating engines, microturbines, or fuel cells, while industrial biomass is generally large scale, using generators such as steam or gas turbines with a capacity greater than 1 MW.

Biomass fuels from the agricultural sector (e.g., crop waste such as bagasse – from sugar, rice hulls, rice straw) are not considered in this study. Due to high moisture content and varying ability, crop residues are not a viable fuel alternative for most CHP applications.[103] In addition, the prime energy producing crops (sugar cane and rice) are largely not present in PacifiCorp's territory.

Non-Renewable Generation. Non-renewable generation includes all technologies that require burning a fossil fuel, such as natural gas or diesel, in a generator to produce electricity. In this study, only natural gas is considered because it is readily available and environmentally cleaner burning than diesel.

This study only considers on-site CHP generation that is primarily used for the building's energy and heat needs. Large "central-station" CHP generation facilities that operate to sell the majority (or all) of their power to the grid are outside the scope of this work. It should be recognized, however, that those plants can provide a large amount of potential that is already modeled in the

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

102 This is commonly referred to as *cogeneration*.

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

PacifiCorp IRP process; for example, in Oregon, such facilities currently generate over 1,000 MW.

Background Data

The primary data source for installed cost of CHP technologies is the California's Self-Generation Incentive Program (SGIP).[104] This program, funded by the major investor-owned utilities of California, provides varying levels of incentives for individual customers to install various distributed generation technologies, including CHP, with a maximum capacity of 5 MW. This program has been in effect since 2001 and has a publicly-available database of all installations, including generation technology, capacity, fuel, and total cost.

For the CHP assessment, nameplate capacity is based on the weighted average of the units installed through California's SGIP for both non-renewable generation and anaerobic digesters. Typical nameplate capacities for industrial biomass vary widely; a 4,800 kW unit is used as a proxy based on a study for the Energy Trust of Oregon.[105] It should be realized that larger capacity units (20 MW) can be installed. These values are summarized in Table 68. Also shown in the table is the net fuel heat rate, measure life and capacity factors for the different generators. Heat rates are from literature values,[106] but based on a weighted average of CHP units from the SGIP data. The measure life and capacity factors were also obtained from the literature.[106] Note that these values are assumed equivalent across PacifiCorp's territory.

Table 68. CHP Prototypical Generating Units

Technology	Nameplate Capacity (kW)	Fuel Heat Rate (MMBTU/MWh)	Measure Life (years)	Capacity Factor
CHP: Non-Renewable				
Reciprocating Engine	661	5.0	20	0.9
Microturbine	158	7.4	15	0.9
Fuel Cell	696	5.8	10	0.95
Gas Turbine	3,174	6.6	20	0.95
CHP: Renewable				
Anaerobic Digesters	400	N/A	15	0.8
Industrial Biomass	4,800	N/A	20	0.9

Note: no heat rate is given for the renewable generation technologies; since the fuel is produced on-site the heat rate is not relevant.

With these prototypical generating units, the associated costs are determined from the SGIP database or, for industrial biomass, literature values.[105] The installed costs include: planning and feasibility, engineering and design, permitting, generator equipment costs, waste heat recovery

[104] http://www.cpuc.ca.gov/static/energy/electric/051005_sgip.htm

[105] "Sizing and Characterizing the Market for Oregon Biopower Projects," prepared for Energy Trust of Oregon, by CH2MHill, 2005.

[106] "Gas-Fired Distributed Energy Resource Technology Characterization," National Renewable Energy Laboratory, NREL-TP-620-34783, 2003.

costs, construction and installation, interconnection, service contracts. The SGIP database costs were reduced by 17% to remove the included sales tax (7%) as well a 10% reduction based on higher costs typical of the California market.[107]

It should be noted that, for generators used with anaerobic digesters, any of the three CHP technologies could be used; thus, the costs can vary widely. In this analysis, a weighted average cost of the technologies, based on adoption proportions in California, is assumed. These costs are reported in Table 69, which also includes the assumed annual installed cost reduction, based on technology improvements and adoption of streamlined siting and interconnection requirements.[106] These reductions will reduce or negate the effects of inflation (annual increase of 1.9%). Administration costs of 15% of the capital expense are included in total cost and increase with inflation. Fuel costs are calculated from the heat rates and vary by state using the 03/07 Forward Price Curve data for site-specific natural gas prices plus transportation and tariff adders.[108] The fuel cost given in the table is an average across all states and represents 2008 natural gas prices. Specifics on state-by-state fuel costs are given in Volume II, Appendix E. Together, this allows a full life-cycle cost analysis of the resource.

Table 69. Costs for Assessed Technologies (2007$)

Technology	**Installed Cost** ($/kW)	**Installed Cost Reduction** (%/yr)	**Annual O&M Costs** ($/kW)	**Annual Fuel Cost** ($/kW)
Reciprocating Engine (RE)	1,969	1%	79	316
Microturbine (MT)	2,831	3%	71	468
Fuel Cell (FC)	5,697	5%	17	385
Gas Turbine (GT)	1,838	1%	58	438
Anaerobic Digesters	3,219	3%	67	0
Industrial Biomass	1,800	0.5%	39	0

CHP Technical Potential

The technical potential for CHP assumes that all technologies will be adopted in all available customer sites to meet their average annual electric demand, regardless of cost or other market barriers. This applies to all C&I building types, large industrial biomass-producing facilities, and sites that may use anaerobic digesters. These three sectors, however, need to be treated separately. To derive this potential, PacifiCorp's 2006 customer database was used; as such, the technical potential given is ramped up from the first-year load. Details on the resources used are given in Volume II, Appendix E. The technical potential by resource category and state is given in Table 70.

Renewable: Anaerobic Digesters. The best candidates for anaerobic digesters include animal farms (dairy or swine), landfills, and wastewater treatment facilities. For farms, the amount of biogas that can be generated is directly related to the number and type of animals on site. Based

107 RS Means, 2007

108 As provided by David Engberg of PacifiCorp

on typical collection systems, a study by the EPA assumes that one cow will generate 2.5 kWh/day and one pig will generate 0.25 kWh/day.[109] Given size constraints, it is likely that only dairy farms with more than 500 head of cattle or 2,000 head of swine will install a generator. Based on the number and average size of farms across the states (by zip code) within PacifiCorp's territory,[110,111] an overall potential is calculated.

Wastewater treatment facilities are similar to farms; the population served by a particular facility will determine the expected generation output. A study by the Federal Energy Management Program assumes that 10,000 people will generate approximately 1 million gallons of waste per day (1 MGD). Each 1 MGD of waste can produce about 35 kW of energy; as such, generally 3 MGD is the minimum waste flow before an anaerobic digester will be installed.[112] Thus, only population centers with 30,000 people or greater are considered for wastewater generation. Finally, for landfills, the US EPA Landfill Methane Outreach Program (LMOP) encourages the implementation of generators at landfills. As part of this program, a database of participating and candidate landfills, based on waste-in-place and throughput, is available by state (with zip code resolution).[93]

Renewable: Industrial Biomass. The industrial biomass potential is based on customers with an average annual electric load greater than 1 aMW in the four key biomass-producing industries: lumber, food, pulp and paper, and chemical manufacturing. The PacifiCorp customer database is used to determine the overall load associated with these industries. For buildings with a load between 1 aMW and 5 aMW, an average load of 2.5 aMW is assumed; for those with larger than 5 aMW annual load, the actual customer load was taken from the customer database. All industrial biomass facilities within this size range are considered CHP eligible.

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

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

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

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

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

potential in aMW. For buildings with an annual load larger than 5 aMW, the actual customer load is taken from the customer database.

Table 70. CHP Technical Potential by State and Resource Category (aMW in 2027)

Technical Potential	CA	ID	OR	UT	WA	WY	Total
Anaerobic Digesters	9	78	91	126	40	14	358
Industrial Biomass	12	284	335	178	83	185	1,076
Non-Renewable	17	31	521	1593	180	810	3,152
Total	**37**	**394**	**947**	**1,896**	**304**	**1,009**	**4,585**

Note: Results may not sum to total due to rounding

CHP Market and Achievable Potential

Prior to discussing the achievable potential, the first step in the analysis is actually a market potential – an analysis of what the market may accept, not all of which is necessarily economic. The market potential is based on adoption rates within other programs (primarily SGIP in California). This analysis is fairly independent of the technical potential, but gives reasonable results based on adoption rates through other programs. In addition, a survey of PacifiCorp customers provides territory-specific information.

Survey Results

Although the market potential is primarily based on an adoption within the California market, the survey results give some insight into applicability of PacifiCorp territory. Full descriptions of survey results are given in Volume II, Appendix A and shall only be described briefly here. In general, there is low level of knowledge – only 21% of surveyed customers were familiar with CHP systems. However, of those who are familiar, 28% (or 6% of the total sample) believe their company would be interested in installing a CHP unit in the future. This 6% of total surveyed customers represents 7.6% of the total load of surveyed customers. As such, without a rigorous education campaign, PacifiCorp could potentially achieve 7% of technical potential, purely based on current interest levels.

Renewable: Anaerobic digesters. The availability of potential sites for anaerobic digesters (farms, landfills, wastewater treatment facilities) is area specific; therefore, the adoption rate from other states' programs may not be representative for PacifiCorp territories. Instead, the potential was based on a similar adoption percentage of the technical potential (2% in the first ten years of program implementation) as the non-renewable CHP. All anaerobic digesters are installed in the commercial sector and the achievable potential is about 4 aMW in 2027.

Renewable: Industrial Biomass*.* The projected growth in US electricity generation from industrial biomass[113] was used as the basis for growth in generation by biomass within PacifiCorp's industrial sector. The PacifiCorp industrial biomass growth is normalized by the

[113] From Energy Information Administration (EIA) 2007 Annual Energy Outlook.

ratio of the PacifiCorp industrial electrical load to the US industrial load. The state-by-state breakdown is based on the distribution of the technical potential from the four key biomass-producing industries (lumber, food, pulp and paper, and chemical manufacturing) with greater than 1 aMW of annual energy load. As the name indicates, all penetration is in the industrial sector and is about 75 aMW in 2027.

Non-Renewable Generation. The market potential for non-renewable CHP is based upon California's success of implementing CHP installations within SGIP. The results of SGIP were used as an expected generation outcome for PacifiCorp, normalized by the PacifiCorp load compared to the load of the participating SGIP utilities. The SGIP has been in effect for five years and provides incentives that cover approximately 50% of the system cost. With slow initial growth for program implementation and greater expected barriers (e.g., longer payback periods, potentially less statewide support, insufficient interconnection standards, etc.), this generation is targeted for PacifiCorp after ten years of program implementation. The four primary generator technologies (reciprocating engines, microturbines, fuel cells, and gas turbines) were all included in SGIP and treated distinctly in this analysis. It is assumed across all non-renewable CHP that 65% will go toward the commercial sector and 35% will be installed in the industrial sector, with no residential sector penetration, as residential CHP technologies are still nascent. The overall market potential is 71 aMW for non-renewable CHP.

Resource Potential

The results of this analysis indicate a cumulative market potential of 150 aMW from all CHP technologies by 2027 (Table 71). As with all other resources, this potential is scaled up to include state- and sector-specific line-loss adders.[114] The largest potential is from industrial biomass (75 aMW) and non-renewable reciprocating engine (RE) applications (56 aMW). An additional 4.2 aMW is expected to be available through the installation of anaerobic digesters. The state-by-state breakout, based on the state's proportion of the technical potential, is given in Table 72 in order of increasing levelized cost. However, not all of this potential is economically viable.

Table 71. Market Potential for CHP (aMW in 2027)

Sector	Industrial Biomass	Anaerobic Digesters	Non-Renewable				Total
			Recip. Engine	Gas Turbine	Micro-turbine	Fuel Cell	
Industrial	75	0	20	1	2	1	100
Commercial	0	4	36	3	5	3	50
Total	75	4	56	4	7	4	150
% of 2027 System Sales	0.8%	0.04%	0.6%	0.04%	0.07%	0.04%	1.6%
Levelized Cost ($/kWh)	$0.03	$0.07	$0.08	$0.08	$0.11	$0.16	

[114] From PacifiCorp 2004 Transmission & Distribution Loss Study.

Table 72. Market Potential for CHP by State and Technology (aMW in 2027)

State	Industrial Biomass	Anaerobic Digesters	Non-Renewable				Total
			Recip Engine	Gas Turbine	Micro-turbine	Fuel Cell	
CA	1	0	1	0	0	0	2
ID	20	1	5	0	1	0	27
OR	23	1	12	1	1	1	39
UT	12	2	23	2	3	2	43
WA	6	1	4	0	1	0	11
WY	13	0	12	1	2	1	28

Note: Results may not sum to total due to rounding

Levelized costs ($/kWh) are given in Table 71 for each technology, calculated using costs given in Table 69, the levelized fuel price,[115] and a nominal discount rate of 7.1%. As made evident by their levelized costs, not all of these technologies are cost-effective. An avoided cost threshold, based on the levelized cost of the average heavy load hour market price, was used to screen the resources on a state-by-state basis. Only technologies with a levelized cost that is equal to or less than the average levelized avoided levelized are considered achievable. Figure 34 gives the cumulative supply curve for CHP technologies, where the red line represents the economic threshold, based on the average value across all states. Industrial biomass, anaerobic digesters, and reciprocating engines are all cost-effective in all states, and gas turbines are cost-effective in Rocky Mountain Power territory (Idaho, Utah and Wyoming), but not in Pacific Power territory (California, Oregon and Washington), resulting in a total achievable potential of 137 aMW in 2027, or 4.6% of the technical potential.

The percentage of technical potential that is achievable (4.6%) is in line with a secondary assessment of CHP potential in the Northwest.[116] This study estimates the 20-year market penetration to range from 4.4%-7.6% of the technical potential in Washington, Oregon, and Idaho for their base case. Their base case assumes a continuation of current consumer interest levels without any significant technological improvements. This 4.6% is also reasonable as compared to the survey results. As described earlier, approximately 6% of the surveyed customers are potential candidates for CHP installations. The achievable potential, or portion of the market potential that is economic, is given by state in Table 73 along with the cost threshold values.

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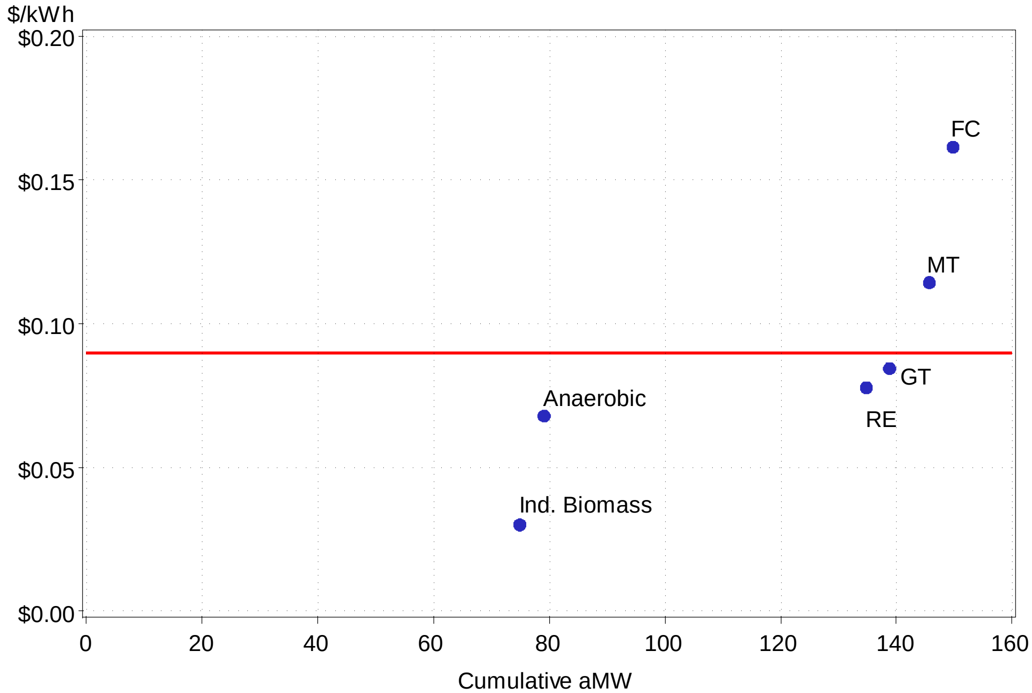
[115] For Table 71, the average fuel price over all states is used, but for the state-by-state analysis, the actual state's fuel price is used.

[116] "CHP Market Potential in the Western United States," Energy and Environmental Analysis, Inc, ORNL Report: B-REP-05-5427-013, 2005.

Figure 34. CHP Cumulative Supply Curve, by Technology (Cumulative aMW in 2027)



RE: Reciprocating Engine, GT: Gas Turbine, MT: Microturbine, FC: Fuel Cell

Table 73. Achievable Potential for CHP by State with Cost Threshold

	CA	ID	OR	UT	WA	WY	PacifiCorp System
Achievable Potential (aMW)	1	26	36	38	10	26	137
Cost Threshold ($/kWh)	$0.084	$0.089	$0.084	$0.089	$0.080	$0.089	$0.086

CHP Alternative Resource Scenarios

Additional economic scenarios account for the uncertainty around the cost threshold and for potential changes to the natural gas prices that affect the non-renewable generation levelized costs. The same percentage change in the annual market price for electricity is used for the gas price (i.e., fixed market heat rate). The updated levelized costs, averaged across all states for both scenarios, are given in Table 74. Note that, for the renewable CHP options (industrial biomass and anaerobic digesters), there is no change in levelized cost across the three economic scenarios because there is no associated fuel price. The cost thresholds, along with the achievable potential by state, are given in Table 75.

Table 74. CHP Average Levelized Costs ($/kWh) for Different Economic Scenarios

Economic Scenario	Industrial Biomass	Anaerobic Digesters	Non-Renewable			
			Recip. Engine	Gas Turbine	Micro-turbine	Fuel Cell
Base Case	$0.03	$0.07	$0.08	$0.08	$0.11	$0.16
High Case	$0.03	$0.07	$0.09	$0.10	$0.14	$0.18
Low Case	$0.03	$0.07	$0.07	$0.07	$0.10	$0.15

Table 75. CHP Alternative Economic Scenarios for Base Achievable Potential by State (aMW in 2027)

	CA	ID	OR	UT	WA	WY	System
Base Economic Scenario							
Achievable Potential (aMW)	1.4	26	36	38	10	26	137
Cost Threshold ($/kWh)	$0.084	$0.089	$0.084	$0.089	$0.080	$0.089	$0.086
Low Economic Scenario							
Achievable Potential (aMW)	0.8	20	23	12	6	13	75
Cost Threshold ($/kWh)	$0.063	$0.066	$0.063	$0.066	$0.059	$0.066	$0.065
High Economic Scenario							
Achievable Potential (aMW)	1.4	26	37	38	10	26	138
Cost Threshold ($/kWh)	$0.120	$0.128	$0.120	$0.128	$0.115	$0.128	$0.123

For the low economic scenario, only industrial biomass is cost-effective across all states. The achievable potential is 75 aMW in the low economic scenario.

In the high economic scenario, gas turbines become cost-effective in Washington and Oregon. However, the contribution of these gas turbines is minimal and does not significantly add to the total achievable potential. The potential increases slightly to 138 aMW.

For CHP, the base achievable potential was derived from the California SGIP that covers approximately 50% of the cost. If this incentive level were increased, a greater potential would be realized. Assuming an elasticity of 0.5, the achievable potential would increase by 25% with an increase of 50% in the incentive level (to 75% incentives), as was shown in Table 67. It should be realized that, within a given economic scenario, the expected achievable potential is a best estimate.

On-Site Solar Results

On-site solar encompasses both energy-efficiency measures that use solar energy as well as solar-electricity generation (building photovoltaics). Two solar efficiency measures are analyzed: solar water heaters and solar attic fans, which are both measures that affect a specific end use. Building photovoltaics (PV), on the other hand, generate electricity for general building consumption. Since on-site solar resources are used to off-set annual energy usage, they are considered, like CHP, an energy-focused resource.

Solar Efficiency Measures

The principle objective in the analysis of solar efficiency potential is to obtain reasonable and reliable estimates of long-run opportunities based on an end-use modeling approach. Solar efficiency resource potential for electricity is analyzed for six residential segments: existing and new construction of single-family, multi-family, and manufactured homes.

Solar Water Heaters. Solar water heaters or solar thermal collectors are typically connected to the domestic hot water system and generate hot water for a home. This technology helps offset the energy required to heat the domestic hot water system. Commonly, these systems are set up so that the solar water heater (one- or two-tank systems) provides primary water heat, which preheats water before it enters the supplemental or conventional water heater. Solar water heaters almost always require some type of supplemental system during cloudy weather and increased demand.

Solar Attic Fan. A solar attic fan is a device to ventilate the attic space for cooling by means of a PV powered fan. The fan typically operates when the sun is shining using a 10 Watt to 20 Watt PV module to power a DC motor. The fan cools the attic space, thereby reducing the energy required to air condition the living space during hot summer days. Depending on the model, the solar fan exhaust air a rate of 800 to 1,200 CFM.[117] For best results, residences should have soffits or gable vents to allow the fan to generate adequate air flow through the attic space.

Building PV

Building PV systems are weather-dependent and rely on the sun to generate electricity. This study focuses on renewable-electricity generation potential from rooftop residential and commercial buildings. Typically, PV generation only offsets a portion of the baseline loads and, in most cases, is considered as a secondary source of a building's energy needs. When excess PV electricity is generated (more than the building's loads), it is fed back into the grid. This depends heavily on the PV system size and generally occurs for residential and commercial customers when the building is not occupied.

In this study, the three primary PV technologies considered are (1) mono-crystalline (single crystalline cell), (2) poly-crystalline (multi-crystalline cell), and (3) amorphous thin-film. These three technologies currently dominate the solar market.[118] Efficiencies of these technologies are improving annually and are taken into account in this study. Large PV generation facilities that operate to sell the majority (or all) of their power to the grid, and emerging PV technologies, are not included in this study.

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[117] Source: ToolBase Services c/o NAHB Research Center – www.toolbase.org

[118] EIA, based on photovoltaic cell and module shipments by type, 2005.

On-Site Solar Background Data

The primary and secondary resources for installed cost of all on-site solar options are from the PacifiCorp's PV pilot program in Utah (the Solar Incentive Program), the California Energy Commission, the Energy Trust of Oregon (ETO), the U.S. Department of Energy, and other on-line sources. For the solar efficiency measures, the ETO estimates an average residential solar water heater system costs $7,000 to install with 2,400 kWh of annual usage. This roughly translates into a 2 kW system, as shown in Table 76. A typical 10 Watt solar attic fan costs around $540 to install.

An analysis of costs for other programs' PV installations results in an average installation cost in 2006 of $9 per Watt,[119] which is assumed in this analysis. Remaining consistent with assumptions from PacifiCorp's PV pilot program in Utah, the operational and maintenance (O&M) costs include inverter replacement every ten years and seasonal module washing.[120] Other technical data have been sourced from multiple primary and secondary resources to determine measure life and state capacity factors. For this analysis, the measure life for a PV system is 25 years.[121] These costs are also shown in Table 76. Consistent with other resources, PacifiCorp's administration cost is assumed to be 15% of the total capital cost. The administrative adder increases with inflation (1.9%), but it is assumed that the capital costs are nominally constant (therefore decreasing in real terms), based on historical trends.

Table 76. On-Site Solar Technology Costs and Measure Lives

Technology	Installed Costs ($/kW)	O&M Costs ($/kW)	Measure Life (years)
Solar Water Heating	$3,500	- - -	15
Solar Attic Fan	$54,000 $540 per unit	- - -	10
Photovoltaic (PV)	$9,000	$100	25

On-Site Solar Technical Potential

The methodologies to calculate potential are different between the solar efficiency measures and solar generation (PV) and, therefore, are treated separately.

Solar Efficiency Measures. The technical potential is based on the Class 2 DSM end-use modeling approach discussed in Section 3, which basically develops a baseline end-use forecast and an alternative forecast with energy efficiency. The difference between the two forecasts determines the technical potential. The alternative end-use forecast includes assumptions of the

119 "Solar Trends: California Energy Commission" by SunPower Consulting LLC provided cost analysis, August 2006.

120 Burton Consulting, LLC: Email correspondence regarding Utah's solar program.

121 Data was averaged from the following sources: NREL, NW Power, and Conservation Council, and typical warranty periods.

technical feasibility of both solar water heaters and the solar attic fans accounting for orientation and shading restrictions, installation constraints, and compatibility factors. The technical feasibility factor for solar water heaters and solar attic fans are 15% and 50%, respectively.

Building PV. Analysis of this technical potential is based on rooftop applications only. This provides a conservative estimate since other applications such as ground or pole mounted PV, awnings, and car ports are not considered. This estimate of the technical potential considers the physical limitations due to roof area, shading, orientation, and expected building growth. Each input will be described in detail below, with details available in Volume II, Appendix E.

Existing Stock and Forecasting. Available square footage of roof area is based on PacifiCorp's existing stock and the Energy Decisions survey. The load forecast is used to estimate the growth in the building stock.

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

- All commercial rooftops are considered flat (0° pitch)
- 30% of all roofs are unavailable (20% due to obstructions and equipment, 10% space lost due shading from the equipment)
- Urban structures have an additional 10% reduction in available space due shading by other surrounding buildings; urban/rural split is designated by zip code
- All building types are equally distributed across all zip codes within a state

These factors together determine a weighted total available roof space for each state.

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

- Single-family and manufactured households have 4/12 (18.5°) pitch roofs
- Multi-family structures have flat roofs (0° pitch)
- 25% of roofs are south facing
- 81% of the roof area is unavailable due to shading
- Rural homes have an additional reduction in shading from the increase of surrounding trees; urban/rural split is designated by zip code
- All building types are equally distributed across all zip codes

These factors together determine a weighted total available roof space for each state.

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

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

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

PV Watts Performance Calculator. The PV Watts performance calculator, developed by National Renewable Energy Laboratory, is used to determine the capacity factor for each state. The amount of solar insolation determines the performance potential for each region. Weather stations were chosen equivalent to those used in the simulation models (see Volume II, Appendix F). The main assumption from PV Watts is the DC to AC de-rate factor of 77%. All commercial and multi-family buildings are fixed with 0.0° array tilt (flat roof), while single-family and manufactured homes are fixed at 18.5° tilt (4/12 pitch). The end result produced capacity factors for each state, which are shown in Table 77.

Table 77. Solar Annual Capacity Factors, by State

	CA	ID	OR	UT	WA	WY
Capacity Factors	0.13	0.13	0.13	0.14	0.12	0.14

The technical potential for on-site solar is 3,537 aMW, primarily from building PV, where the solar-efficiency measures component is 2.6 aMW. Table 78, below, shows the technical potential by state in year 2027, incremental to existing capacity. It should be noted that, for the solar efficiency measures, the technical potential takes into account only electric-related end uses. For example, in the case of solar water heaters, each state has different fuel shares associated with water heating (natural gas or electric). This drives the potential down in some states, such as Utah, where the large majority of domestic hot water heating is done by natural gas. In the case of solar attic fans, the only end use affected is central air conditioning. Utah has the largest residential population and cooling load requirement resulting in the highest technical potential.

Table 78. On-Site Solar Technical Potential by State (aMW in 2027)

Technical Potential	CA	ID	OR	UT	WA	WY	Total
Photovoltaics	43	132	982	1,919	170	291	3,537
Solar Water Heater	0.1	0.1	1.0	0.3	0.2	0.1	1.9
Solar Attic Fans	0.0	0.0	0.2	0.5	0.0	0.0	0.8
Total	**43**	**132**	**983**	**1,920**	**170**	**291**	**3,540**

Note: Results may not sum to total due to rounding

On-Site Solar Market Potential

Solar Efficiency Measures. The market potential for solar water heaters is based upon the success of ETO's solar program. ETO has completed 102 successful installations in PacifiCorp's Oregon territory. According to the Energy Decision survey, 67% of PacifiCorp's Oregon residential customers have electric domestic hot water heaters; therefore, it is assumed that roughly 68 of these solar water heaters installations were by households using electric water heaters. The ratio of current capacity, in MWh, assuming annual production of 2.4 MWh per system, by the technical potential, in MWh, results in a market potential is 9.5% of the technical potential. Results are provided below in Table 79.

The solar attic fan is more difficult to quantify due to the lack of available installation data. Therefore, the same estimation for solar water heaters is used: 9.4% of the technical potential is used to determine the market potential for the solar attic fans.

Building PV. The market potential for PV is based upon solar programs from around the country. The following sources were used to determine the adoption rate of implementing PV installations within their region: New Jersey's Clean Energy Program™, Connecticut Clean Energy Fund, Energy Trust of Oregon, Florida Energy Office's Solar Energy Systems Incentives Program, Massachusetts Technology Collaborative's Small Renewables Initiative, and California Energy Commission's Renewable Energy Program with San Diego Gas & Electric.[122]

The success of a program is, in part, dependent on the current incentives available. Incentives can be provided by one or more of the following: federal tax incentives, state tax incentives, utility buy-downs, production-based incentives, and other rebates. Volume II, Appendix E lists several state programs from around the country offering PV incentives.[123] Incentives have become critical in promoting and creating a successful PV program. Depending on the type and size of incentive, it can affect the adoption rate. In most instances, the total incentive is roughly 50% of the installed cost for the residential market and 75% for the commercial sector. The market potential is based on existing programs implementing these levels of incentives and is calculated from their adoption rates. The resulting market potential is less than 1% (average of 0.09%) of the technical potential.

The resulting market potential percentage may not be appropriate to apply to all states evenly, since each has varying degrees of acceptance and political climate. Across PacifiCorp's territory, each state's adoption rate heavily depends on the existence of current programs, "green" culture, understanding of technology and meteorological considerations, as well as other economic factors. With all of this in consideration, Oregon and Utah have the highest likelihood in successfully succeeding in high adoption rates, while Idaho and Wyoming are less likely to achieve high adoption rates over the next ten years.

122 "Technical Potential for Rooftop Photovoltaic in the San Diego Region," by Scott Anders of the Energy Policy Initiatives Center, University of San Diego School of Law and Tom Bialek of San Diego Gas & Electric, 2005.

123 Database of State Incentives for Renewables and Energy Efficiency (DSIRE) www.dsireusa.org.

For all solar technologies, the market potential is 2.5 aMW with most (2.3 aMW) from building PV. The state-by-state breakout, based on the state's proportion of the technical potential, is shown in Table 79 along with levelized costs. Note that none of this potential is achievable due to the high levelized costs.

Table 79. On-Site Solar Market Potential and Levelized Costs by State (aMW in 2027)

	CA	ID	OR	UT	WA	WY	Total
Photovoltaics							
Potential (aMW)	0.03	0.06	0.67	1.25	0.10	0.14	2.25
Levelized Cost ($/kWh)	$0.85	$0.83	$0.85	$0.79	$0.90	$0.76	
Solar Water Heater							
Potential (aMW)	0.01	0.01	0.10	0.03	0.02	0.01	0.18
Levelized Cost ($/kWh)	$0.37	$0.36	$0.37	$0.35	$0.40	$0.33	
Solar Attic Fans							
Potential (aMW)	0.00	0.00	0.01	0.05	0.00	0.00	0.07
Levelized Cost ($/kWh)	$7.42	$7.28	$7.42	$6.94	$7.92	$6.69	

On-Site Solar Alternative Resource Scenarios

On-Site solar resources are unique in that they are currently not cost-effective based on a total resource cost test, and so the current market potential is purely from customers who are willing to accept long payback times. Thus, there is no expected change in the market potential based purely on a change in avoided cost. However, there may be changes in potential from other factors the affect payback period.

The relationship between the percentage of consumers willing to adopt a technology and payback period can be described by the diffusion of innovation theory developed by Rogers.[124] Diffusion of innovation theory "predicts adoption rate of consumers that purchase a new service or product."[125] Using a categorization model, innovation can be described as five consumer categories of innovators:

- ***Innovators*** **–** Willing to take risk, have resources to pursue new ideas
- ***Early Adopters*** **–** Interested in new ideas, but more cautious and with fewer resources
- ***Early Majority*** **–** Interested, but want to see the idea has worked for others
- ***Late Majority*** **–** Will typically go along with what others are doing
- ***Laggards*** **–** Tend to be the most risk averse and resource constrained

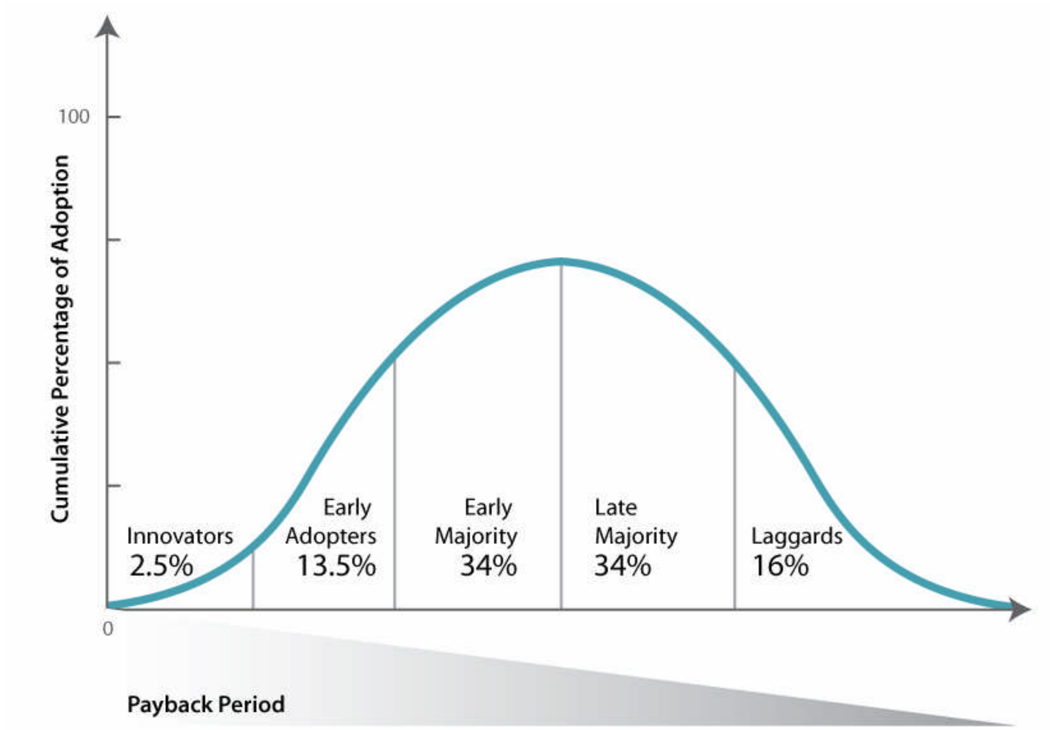
Figure 35 displays the relationships among these groups within a product diffusion curve. Solar technologies remain early on the product diffusion curve. It is plausible to say that the majority

[124] Rogers, Everett M. "New Product Adoption and Diffusion." *Journal of Consumer Research*, March 1973.

[125] *Oregon Photovoltaic Market Characterization* prepared for the Energy Trust of Oregon by Energy Market Innovations, Inc, 2003.

of recent installers of solar technologies may be classified as innovators or perhaps early adopters. When any significant decrease in payback period occurs, the adoption percentage will push forward on this curve and may have an overwhelming effect on the market penetration.

Figure 35. Diffusion Curve for Product Adoption



The relationship between the diffusion curve and payback period is not strictly defined. We assume, however, similar criteria as Kastovich, et al.[126] This results in payback periods of adopters as shown in Table 80.

Table 80. Potential Market Penetration of Adopters by Payback Period

	Innovators	Early Adopters	Early Majority	Late Majority	Laggards
Percent Adoption Range (%)	0% - 2.5%	2.5% - 16%	16% - 50%	50% - 84%	84% - 100%
Payback Period Range (years)	+40 - 10yrs	10 – 7.5 yrs	7.5 – 4 yrs	4 – 2 yrs	2 – 0 yrs

The innovators of this industry are the small scale residential home owners who are willing to take risks regardless of payback periods. Their investment typically is not based on financial rewards, rather social and environmental benefits. At 50% incentive levels for PV, the residential

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126 Kastovich, J.C., R.R. Lawrence, R.R. Hoffman, and C. Pavlak, 1982, *Advanced Electric Heat Pump Market and Business Analysis*, Final Report prepared by Westinghouse Electric Corporation for Oak Ridge National Laboratory, ORNL/Sub/79-24712/1, April.

consumers are still considered innovators with roughly a 30-year payback period. The commercial customers, at 75% incentive level for PV, are also considered to be innovators and are within the range of being early adopters. Commercial building owners currently have roughly a 20-year payback period with this technology and incentive levels. As mentioned before, the commercial sector is generally more sensitive to payback period. It is difficult to quantify the effect of payback period on adoption, but decreasing the payback period to less than ten years can have as much as a two- to three-fold increase in the market potential.

Dispatchable Standby Generation Results

Dispatchable standby generators (DSGs) are on-site generators that customers own and use as backup generation, but that are managed by the utility to use during specified periods to reduce system load. Since backup generators are generally over-sized to meet potential peak demands, the generator could produce excess electricity under normal operating conditions. During a DSG event, the customer receives all of their required power from the generator, and any excess is fed into the grid. Across the country, utilities in San Diego (SDG&E), New York State (NYSERDA) and Hawaii (Hawaiian Electric) have DSG programs. In the Northwest, one of the most successful DSG programs is managed by PGE, and is therefore the basis for this analysis. PGE contracts with customers who own or will be installing a backup generator, agreeing to pay all interconnection costs, as well as annual fuel and other O&M costs. In exchange, the utility is able to activate the generator for up to 400 hours/year (typically) during peak periods and will continue to charge the customer their standard tariffs during these events. Most of the DSGs within PGE's program are diesel-powered reciprocating engines, and it is assumed that, for PacifiCorp, all units will be. The potential from DSG can come from existing or new (yet-to-be-installed) backup generator installations.

DSG Background Data

To aid in determining the required size of backup generator and the overall potential for DSG, Quantec contracted with Energy Insights™ to leverage results from their nation-wide distributed generation surveys. In particular, we obtained the number of businesses with backup generators and the percent of peak load met by each generator. These data were categorized to the building segment for C&I sectors, but not to the state level due to lack of statistical significance; therefore, uniformity across states is assumed. Table 81 and Table 82 give the results from these surveys for the C&I market (building) segments, respectively. From this, an estimate of the potential of a DSG program from existing as compared to new (yet-to-be-installed) backup generators.

Table 81. Existing Backup Generation, Commercial Sector

Customer Segment	Percent Buildings w/ Backup Generation	Average Percent of Peak Load Met
Office	16%	11%
Restaurant	30%	46%
Retail	10%	52%
Grocery	20%	46%
Warehouse	30%	46%
School	40%	33%
Health	69%	39%
Lodging	60%	30%
Miscellaneous	30%	46%

Table 82. Existing Backup Generation, Industrial Sector

Customer Segment	Percent Buildings w/ Backup Generation	Average Percent of Peak Load Met
Mining	17%	28%
Chemical Manufacturing	95%	53%
Petroleum Refining Products	17%	28%
Food Manufacturing	14%	28%
Stone, Clay, Glass Products	26%	28%
Primary Metal Manufacturing	63%	6%
Industrial Machinery	2%	15%
Electrical Equipment Manufacturing	19%	12%
Transportation Equipment Manufacturing	20%	28%
Lumber & Wood Products	21%	28%
Paper Manufacturing	3%	28%
Other Industrial Manufacturing	17%	28%

Since each state has permitting requirements that would limit the installation of backup generators, only equipment that would be exempt from the permitting process is included in this analysis (e.g., Salt Lake City, UT, allows – without permitting – the installation of a diesel-powered backup generator that is less than 750 kW and runs for less than 300 hours/year). Each state's exemptions are given in Table 83. Note that different states stipulate different limits (size, hours, and/or NO_X emission), and those numbers are given in bold text.[127] The other numbers were calculated based on the EPA 2007 Tier II emission standards (applicable to generators greater than 560 kW) that limit the allowable amount of grams NO_X per kW-hr produced. Based on these requirements, only buildings whose demand would require a generator sized less than

[127] This analysis does not take into account volatile organic compounds (VOC) emission concerns.

the permitting limit are included in the potential. This is primarily a consideration for Utah, Wyoming, and Washington, where the size/hour limits are significant.

Table 83. State Emission Standards for Diesel Backup Generators

State	Hour Limit (per year)	Size Limit (kW)	Emission Limit (tons NO_X/yr)
CA		17,719	**250 lb/any hour**
ID	**500**	28,350	**100**
OR	400	13,820	**39**
UT	**300**	**750**	
WA	1,548	**293**	**2**
WY	1,935	**2,930**	**40**

Notes: Emission limits in tons NOx/yr, except CA which is in lb/any hour.
CA limits are for Siskiyou and Modoc counties.
UT limits are for the Salt Lake City region, but used for the entire state.
WA limits either size *or* emissions. Hours limit is based on assuming both.
OR size limit is based on a 400 hour limit

From the PacifiCorp customer database, the peak energy demand by building type was categorized into seven demand bundles (<30 kW, 30 kW-99 kW, 100 kW-199 kW, 200 kW-499 kW, 500 kW-999 kW, 1 MW-4.9 MW and >5 MW, monthly maximum demand). For the >5 MW category, actual peak energy demand by building is used. The percent of load met by the backup generator is then multiplied by the maximum demand of this bundle to obtain an estimate of the expected size of the backup generator unit.

These categorized peak consumption data, along with the permitting size limits, were used to determine the technical potential. If the peak demand is larger than the permitting limit, that amount of load is removed from the overall potential. For example, a large chemical manufacturing plant may have a peak load of 2 MW. With 53% of the load covered by the backup generator unit (Table 82), that would imply the generator has a capacity of 1.1 MW. In Utah, however, this unit would exceed the exemption limit of 750 kW, and so this load is not counted as part of the technical potential. In addition, it is assumed that the minimum size generator that PacifiCorp will consider is 200 kW, based on PGE's program experience. The technical potential by state is given in Table 84.

Table 84. DSG Technical Potential by State (MW in 2027)

Technical Potential	CA	ID	OR	UT	WA	WY	Total
DSG Existing	7	22	146	279	19	50	523
DSG New	9	25	231	623	28	127	1,043
Total	**16**	**47**	**377**	**902**	**47**	**177**	**1,566**

Note: Results may not sum to total due to rounding

The first year and O&M (including fuel) costs will differ for buildings that currently have DSG units and those planning on installing new units, and are given in Table 85. In general, including existing units will be more expensive because of potential retrofitting constraints (interconnection and switching gear may not fit in space) and greater maintenance needs. Because of these differences, the two categories are treated separately. A 15% administrative cost is added to the initial and O&M costs. Details on assumed costs and all other input data are given in Volume II, Appendix E.

Table 85. Costs for DSG

Costs	New DSG	Existing DSG
First-Year ($/kW installed)	$175	$250
O&M ($/kW-year)	$26	$29
Levelized Cost ($/kW-year)	$52	$61

DSG Achievable Potential

The achievable potential was calculated using the same methodology as Class 1 and Class 3 DSM resources. A 10% program participation rate is assumed, based on PGE's adoption rates. The 2027 achievable potential by state, for existing and new DSGs is given in Table 86, with a total of 136 MW for both DSG programs.[128] Using an economic cost threshold of $98/kW in the Rocky Mountain Power territory (UT, WY and ID) and $58/kW in the Pacific Power territory (OR, ID, UT), both existing and new DSG installations are economic in the Rocky Mountain Power territory and only new DSG installations, which have a levelized cost of $52/kW, are economic in the Pacific Power territory. When compared with other capacity-focused resources, there are interaction effects that should be considered. DSG will directly compete with other programs that target large (>250 kW) customers. As such, if these customers decide to use their backup generator within a different program (e.g., curtailable tariffs), then the net achievable potential for DSG will be reduced. Other Class 1 and Class 3 DSM-type programs around the country have found that about half of the customers participating in a curtailable tariff program use their backup generators to reduce their load.[129] Assuming the potential for curtailable tariffs doubles with including customers that have standby generators; this reduces the overall DSG potential by about 43 MW to 93 MW.

[128] Based on correspondence by the Utah Department of Environmental Quality (to Pete Warnken, PacifiCorp, dated 9/18/06), it is likely that the state will not support a DSG program due to concerns with the impact on ozone levels by the utilization of backup generators.

[129] Interview with Rick Counihan of EnerNoc, referring to ISO New England Curtailable Load Program.

Table 86. Achievable Potential and Cost for DSG (MW in 2027)

DSG	CA	ID	OR	UT	WA	WY	Total
Existing Installations							
Commercial	- - -	0	- - -	18	- - -	3	21
Industrial	- - -	2	- - -	9	- - -	2	13
Total	- - -	2	- - -	27	- - -	5	34
New Installations							
Commercial	0	0	22	47	2	4	77
Industrial	1	2	0	13	1	8	25
Total	1	2	23	60	3	12	102

Note: Results may not sum to total due to rounding

Alternative Scenarios

The same average percent change in the base, low and high market price forecasts are assumed for the capacity-focused resources. That is, the decrements increase by 48% in the high economic scenario and decrease by 30% in the low scenario. The achievable potential for the different economic scenarios are given in Table 87.

Table 87. Alternate Economic Scenarios for DSG Base Achievable Potential by Territory (MW in 2027)

	Rocky Mountain Power	Pacific Power	PacifiCorp System
Base Economic Case			
Achievable Potential (MW)	110	26	136
Cost Threshold ($/kW)	$98	$58	
Low Economic Case			
Achievable Potential (MW)	110	---	110
Cost Threshold ($/kW))	$68	$40	
High Economic Case			
Achievable Potential (MW)	110	43	153
Cost Threshold ($/kW)	$145	$85	

For DSG, a higher achievable potential may be possible if PacifiCorp is able to effectively recruit customers for participation. The assumption for the base case is that PacifiCorp will sign on 10% of the load, based on what PGE has captured over the past six years. It is possible, with aggressive campaigning, that PacifiCorp might garner 15% of the load. This increases the overall potential by 150%, as was shown earlier in Table 67.

6. Effects of Structural Changes

Overview

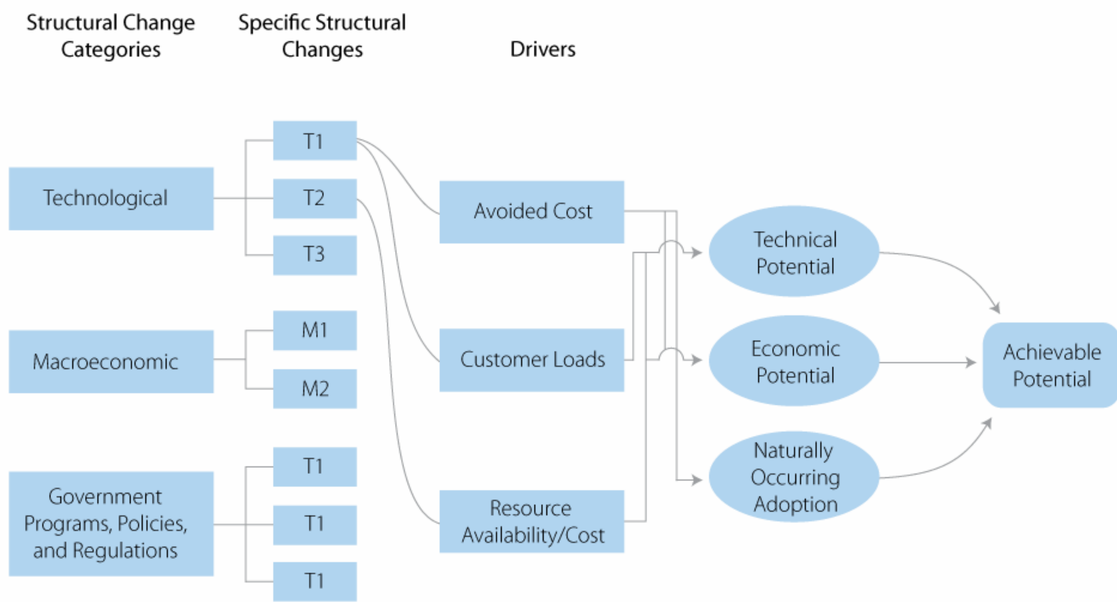
The estimates of various DSM resources analyzed in this study are based on key assumptions, such as avoided costs and market acceptance, which have significant uncertainty over a 20-year period. There are a number of fundamental structural changes that, if they occur, would likely have a profound effect on the magnitude and cost of the identified resources, as well as on the strategies for their acquisition. The structural changes likely to affect the results of this study may be roughly classified into three distinct categories: macro-economic, technological, or public policy. Table 88 shows these categories and illustrative examples of each.

Table 88. Categories of Structural Changes and Examples

Category	Examples
Macroeconomic	▪ New customer end uses ▪ Short-term fuel supply disruptions/price spikes ▪ Increasing consumer environmental concerns
Technological	▪ Breakthrough demand reduction technologies ▪ Breakthrough efficiency technologies ▪ Distributed generation innovations
Public Policy	▪ Increased state or federal tax credits for efficiency or renewables ▪ New or increased public purpose charge ▪ Limits or taxes on carbon emissions ▪ Renewable Portfolio Standard (RPS) ▪ More stringent codes and standards

The effects of these changes might manifest themselves in terms of a set of *drivers*, principally resource costs, overall consumer demand for electricity, resource costs, and/or the utility's avoided costs. Depending on the type of change and specific drivers, these structural changes may affect technical, economic, and/or achievable potential. Figure 36 shows schematically how various structural changes are linked to the potential estimates. The figure illustrates how a set of hypothetical technological structural changes are connected to the three primary drivers, which, in turn, influence the technical and economic potential, naturally occurring adoption, and, ultimately, the estimated achievable potential.

Figure 36. Illustration of Linkages between Structural Changes and Achievable Potential



Macroeconomic Structural Changes

In terms of macroeconomic structural changes, there are several changes that could influence the potential estimates:

Significant growth in new customer end uses is expected to increase the quantity of potential available by expanding the customer load to which efficiency and other improvements would apply. Growth of end uses is most likely to occur in the residential or commercial sectors, primarily in plug loads as new consumer electronics and information processing technologies are introduced and customers adopt them. This study utilizes customer sector, customer segment, and state-level load forecasts from PacifiCorp, which include trends in customer behavior. For example, these forecasts include residential energy consumption changes due to falling electric hot water and space heating loads and increases in demand for air conditioning. Yet, the future trends for new consumer technologies, such as plasma and high-definition televisions, are unclear at this point. An analysis of current home electronics usage is given in Volume II, Appendix F.

Major energy supply shortages and/or price increases. Major shortages in energy supplies (such as natural gas or oil) are likely to be accompanied by significant energy price increases. Higher prices for fuels to generate electricity will have a direct effect on avoided costs, and higher avoided costs increase achievable potential, both by increasing the cost-effectiveness of measures and the likelihood of customer participation in DSM programs. This study includes a "high" economic scenario with cost thresholds that are significantly above the base case (48%). At the same time, both energy shortages and higher prices could decrease customer loads, and therefore potential, through an increase in naturally occurring conservation (or possibly shifts to alternative fuels or renewables). Because these two effects counteract each other, estimation of the final impact of energy shortages would require a substantial analysis incorporating customers' elasticity of demand, which is out of scope of the current study, but may be a future research opportunity.

A significant shift in consumer environmental awareness of energy consumption is likely to increase the amount of potential that is achievable due to increased participation rates, and may also likely reduce potential by increasing the naturally occurring rate of conservation. In the commercial sector, one change that has received recent attention, particularly in the Northwest, is a shift toward green businesses. Various groups at the local and state level have been promoting green business as a major focus of economic development.[130] There may also be a significant growth in customer awareness of environmental impacts affecting behaviors and choices, such as green building, organic food purchases, and renewable power program participation.[131] Our analysis includes the impact on potential of high achievable assumptions, which would account for most of these impacts. A significant study would be required to assess the likely impacts on naturally occurring conservation from a shift to "green" attitudes.

Technological Changes

There are two general types of changes that could influence the estimates of potential: breakthrough technologies and major price or performance improvements of current technologies.

New breakthrough efficiency technologies would have two counteracting impacts. New, more efficient technologies may increase the potential for energy efficiency overall, although some of these may be in the form of substitutes for existing efficient technologies (e.g., LED lighting replacing CFL technology). Second, it would likely drive customer loads lower through increased natural adoption of efficient technologies. In the analysis of achievable potential, emerging technologies have been modeled, with assumptions regarding the timing of market readiness and market saturation. These probably could not be classified as "breakthrough" technologies, but they do encompass the best available knowledge regarding major expected technological shifts. For example, the results of this study indicate that should efficiency levels for the standard refrigerators increase to ENERGY STAR requirements, the total technical potential would be reduced by over 8 aMW. Similarly, technological changes in refrigeration compressors improving efficiency from 40% to 60% would reduce technical potential in the commercial sector by nearly 5 aMW.

Major price or performance improvements of existing customer technologies would also lead to counter-acting impacts on potential. First, improvements would be likely to increase the rate of

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130 The Portland Development Commission is one example. Efforts spearheaded by the mayor of Salt Lake City are another example (http://www.grist.org/news/maindish/2007/02/06/anderson/index.html?source=daily).

131 The recent growth in the market for green buildings has been substantial, particularly in the Northwest. Nationally, a McGraw-Hill Construction/National Association of Home Builders (NAHB) survey indicated that there was a 20% increase in 2005 among those in the home building community who were focusing their attention on green, environmentally responsible building. Expectations for 2006 were for another 30% increase (http://www.greenbiz.com/news/news_third.cfm?NewsID=30948).

naturally occurring adoption, thereby reducing potential. Declines in cost, for those measures not currently cost-effective, would increase the potential by allowing more measures into the economic screen. Our analysis captures gradual price declines by assuming a constant nominal cost (i.e., declining real cost), thereby accounting for overall market price changes, absent data regarding the direction and timing of abrupt changes in individual technologies. For supplemental resources, photovoltaic technologies, micro-turbines and fuel cells are relatively new technologies; there may be a significant shift in prices over the planning horizon. For example, between 1998 and 2005, the cost for photovoltaics declined nearly 20%.[132] Fuel cells have had a dramatic decrease in cost, with a drop of about two orders of magnitude from when they were first introduced for the space program nearly forty years ago through today.[133] For capacity-focused resources, it is likely that the Energy Policy Act of 2005 (EPACT 2005) recommendations for advanced meter reading and time-differentiated prices will decrease implementation costs (including technology and meters), thereby increasing the quantity of potential that is economically viable.

Public Policy and Regulation

In terms of government policies, programs, and regulations, there are several changes that could influence the potential estimates:

Mechanisms that internalize the cost of greenhouse gas impacts, in particular carbon dioxide (CO_2). Any government action that internalizes the costs of greenhouse gas (GHG) emissions[134] is likely to increase the avoided costs and therefore increase the quantity of economically achievable potential. One study looking at the effects of the Kyoto Treaty conditions estimated that emissions limits would lead to electricity price increases between 20% and 86%, reflecting both the increased fuel costs and the incremental capital investments for non-coal generating capacity.[135] As explained in greater detail in Volume II, Appendix G (Treatment of Externalities), PacifiCorp's current IRP process incorporates these factors. Therefore, the IRP decrements that are used to screen resources account for the likely costs of these factors; our high economic screen has an increased price of 48%, which is consistent with the above-referenced study. For supplemental resources such as dispatchable standby generation, stringent emissions requirements would lower the potential by making the permitting requirements more difficult, allowing for only smaller generators to be considered.

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132 http://www.renewableenergyaccess.com/rea/news/infocus/story?id=46191

133 http://www.fossil.energy.gov/programs/powersystems/fuelcells/

134 A range of approaches to reduce GHG emissions has been proposed and implemented. Most, but not all, approaches are directed at CO_2 emissions specifically. The most probable approaches would be imposition of an emissions tax or implementation of a cap-and-trade market with specified and declining emissions limits. One likely effect of government efforts to reduce CO_2 emissions is to shift electricity generation to fuels or resources that produce less CO_2 per kWh or to technologies that capture and keep the CO_2 from entering the atmosphere.

135 This scenario is based on carbon price peaks early in the 2008-2012 period, reaching between $67 and $348 per metric ton ($18 to $95 per metric ton of CO_2) in 2010, and then declines as energy markets adjust and more efficient, new technologies become available and gradually penetrate the market.
See: http://www.eia.doe.gov/oiaf/kyoto/kyotobrf.html.

Implementation of a renewable portfolio standard (RPS). An RPS is a government policy requiring electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date.[136] The probable effect of an RPS is an increase in avoided costs that would make additional resources cost-effective. In addition, some Renewable Portfolio Standards, such as the one recently enacted in Washington, allow for high-efficiency CHP to be counted toward that goal. If other states follow suit, this may greatly increase the interest in CHP. In Oregon, a 25% requirement by 2025, as has recently been adopted by the Oregon legislature.

Significant tightening of building and equipment energy-efficiency standards. Building, appliance, and equipment efficiency codes and standards have been made more stringent at both the state and federal levels over the past few decades. As standards increase, the basic efficiency level of new products and buildings in the market increases. The effect of raising efficiency standards can be interpreted as an increase in naturally occurring market conservation, which results in a decrease in the technical potential. In general, the overall effects of tighter standards on potential are limited by several factors including the fact that significant increases in efficiency standards have already occurred, tighter standards are likely to take considerable time to implement, their impacts are limited by the penetration rates of new buildings and appliances, and compliance is less than perfect.[137] Consequently, it seems unlikely that tighter efficiency standards will have a significant effect on achievable potential in the short term.

Nevertheless, there are some exceptions to these general observations that could lead to significant reductions in the potential for new equipment and buildings as a result of government actions. One significant exception is the growing possibility that code changes or legislation will result in CFL bulbs almost completely replacing incandescent bulbs.[138] This could have a significant impact on the potential estimates since nearly 49% (78 aMW) of energy-efficiency potential in the residential sector is in lighting measures, primarily CFL bulbs. Should states in PacifiCorp's service territories decide to ban incandescent bulbs through legislative action, then a substantial share of the identified potential will be realized without the utility's involvement. Another exception is the adoption of local building efficiency codes and standards in locales where there are currently none. Wyoming is one example, where there is neither a statewide residential nor commercial building energy code.[139] If more stringent codes for either sector were adopted, the new construction potential for that sector could decline substantially. In addition, our basic forecasts do not assume any growth in the stringency of building and appliance standards. Historically, such standards have been tightened over time on a regular basis so if

[136] As of the end of 2006, 20 states plus the District of Columbia had RPS policies in place. Two additional states, Illinois and Vermont, had nonbinding goals for adopting renewables instead. The requirements varied from 2.2% to 20% of the amount of electricity generated, with an average requirement around 15% within an average time horizon of 10 years from now. In the West, California and Nevada both have a 20% RPS requirement and Washington and Montana have a requirement for 15% renewable generation.

[137] A recent study completed in California showed very low compliance rates with the new standards for several types of equipment and building efficiency measures. See *Statewide Codes and Standards Market Adoption and Noncompliance Rates*, prepared by Quantec, LLC, for Southern California Edison, SCE0224.01.

[138] Incandescent screw-in bulbs have already been banned in Australia and similar action is being considered by the European Union and Canada. The idea is also being proposed in California.

[139] The assumed baseline for Wyoming new construction is IECC 2003.

these trends continue the standards would erode some of the estimated potential, with the caveat of potentially low compliance, as described above.

Additional or larger tax credits for energy efficiency or renewables. Finally, tax credits have been increasingly popular as a way to promote efficiency increases. EPACT 2005 established federal tax credits for consumers who purchase and install specific products, such as energy-efficient windows, insulation, doors, roofs, and heating and cooling equipment of up to $500 beginning in January 2006. EPACT 2005 also provides a credit equal to 30% of qualifying expenditures for purchase of qualified photovoltaic systems and for solar water heating equipment. For energy-efficiency improvements, examples of state-led efforts include: California providing personal deductions of loan interest on purchases; Idaho providing a tax deduction for the costs of energy-efficiency retrofits; and Montana offering personal and corporate tax breaks for specific energy-efficiency measures. Both residential and business consumer acceptance of renewables is particularly sensitive to tax credits. In 2003, for example, 95% of all PV installations in Oregon were residential and 5% were in commercial buildings. Over time, as incentives increased for the commercial sector through state and federal tax credits, commercial building owners became more willing to participate and, by the end of 2006, the share of PV installations by businesses had increased to 40% of all installations.

The effect of these financial incentives is to reduce the consumer and business cost of energy-efficiency measures, which is likely to have two different effects. First, financial incentives increase naturally occurring adoption of efficiency options, which, in turn, reduces the achievable potential remaining. On the other hand, it seems likely that these incentives would bring the cost of such investments closer to a purchase point for more consumers and businesses so that a utility program would be more effective at increasing the participation of a larger number of customers, thus increasing the achievable potential. Since these two effects tend to counter each other, the net effect on overall achievable potential is uncertain and probably not outside the range of the scenarios already analyzed.

Conclusions

In general, the uncertainties associated with projecting the direction and scope of the changes described above are significant. Additional, targeted research would be required to develop more definitive estimates of the likely effects from structural changes on the potential in this study. Overall, the assumptions in the scenarios we have analyzed cover the most probable ranges for structural changes.

In the macroeconomic category, major energy supply shortages and/or price increases would likely have the largest effect on the potential. However, we have analyzed a case with 48% average annual price increases, and this is likely to encompass all but the most severe long-term supply shortage/price increase possibilities.

In the technological structural change category, we identified breakthrough technologies and major price/performance improvements as the most likely types of changes. In both cases, these changes are likely to produce counteracting effects on the potential estimates so the net effect is likely to be modest and difficult to predict.

There is a multitude of structural changes possible in the public policy and regulation arena. Mechanisms internalizing the cost of greenhouse gas impacts appear to be increasingly likely and the effects on avoided costs could be significant. The avoided cost ranges we analyzed covered these probable impacts. Similarly, the avoided costs analyzed covered the probable economic impacts of implementing an RPS, though specifics of an RPS could greatly increase interest in CHP projects. Expanded tax credits or other financial incentives for energy efficiency and renewables also could affect the potential estimates. However, the net effects are not definitively known, though it is our professional judgment that our analysis adequately covers the range of likely outcomes.

Significantly tighter building and equipment appliance efficiency standards could definitely reduce the achievable potential by expanding the level of market-driven energy efficiency. This is most likely if specific products are essentially banned (e.g., incandescent light bulbs) or standards quickly go into effect for regions or products without existing standards. These effects can be estimated on a case-by-case basis, but they depend on the extent of public pressure, countervailing industry concerns, and political decisions. The largest impact from codes and standards (phase out the availability of incandescent bulbs) has already been quantified and while additional changes in codes and standards may have an impact, this study can be easily updated with new information as it becomes available.